BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-10 _______

EXHIBIT NO._____(RJL-4)

ROBERT J. LAFFERTY

REPRESENTING AVISTA CORPORATION

Form 8-K

AVISTA CORP - ava

Filed: April 17, 2007 (period: April 16, 2007)

Report of unscheduled material events or corporate changes.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington D.C. 20549

FORM 8-K

CURRENT REPORT

**PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934**

Date of Report (Date of earliest event reported): April 16, 2007

AVISTA CORPORATION
(Exact name of registrant as specified in its charter)

Washington	1-3701	91-0462470
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

1411 East Mission Avenue, Spokane, Washington	99202-2600
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 509-489-0500
Web site: http://www.avistacorp.com

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 1 – Registrant's Business and Operations

Item 1.01 Entry into a Material Definitive Agreement.

On April 16, 2007, Avista Energy, Inc. (Avista Energy), a subsidiary of Avista Capital, Inc. (Avista Capital) and an indirect subsidiary of Avista Corporation (Avista Corp. or the Company), and Avista Energy Canada, Ltd. (Avista Energy Canada), a wholly-owned subsidiary of Avista Energy, entered into a purchase and sale agreement with Coral Energy Holding, L.P. (Coral), a subsidiary of the Shell Group of Companies, as well as certain other subsidiaries of Coral. Pursuant to the agreement, Avista Energy will sell substantially all of its contracts and ongoing operations to Coral and Avista Energy Canada will sell substantially all of its contracts and ongoing operations to Coral Energy Canada Inc., a subsidiary of Coral.

Avista Energy is an electricity and natural gas marketing, trading and resource management business, operating primarily within the Western Electricity Coordinating Council geographical area, which is comprised of eleven Western states and the provinces of British Columbia and Alberta, Canada. Avista Energy Canada provides natural gas services to end-user industrial and commercial customers in British Columbia, Canada. Avista Energy's headquarters are in Spokane, Washington, and it also has natural gas marketing offices in Vancouver, British Columbia, Canada and Great Falls, Montana.

The sale will be completed through the purchase and sale agreement and certain other ancillary agreements, including agreements relating to:

- storage rights at a natural gas storage facility located in Washington, and
- energy conversion, electric transmission and natural gas transportation relating to a power generation facility located in Idaho.

As consideration for the assets acquired, the purchase price to be paid by Coral will be calculated on the closing date as the sum of the following (subject to certain adjustments):

- the net trade book value of contracts acquired,
- the market value of the natural gas inventory, and
- the net book value of the tangible fixed assets acquired.

After closing costs and other adjustments, the transaction is not expected to result in a significant gain or loss for Avista Corp. This expectation could change due to several factors including, but not limited to, changes in the market value of natural gas inventory and certain other contracts and changes in the estimate of transaction costs and other costs associated with closing out Avista Energy's operations. Proceeds from the transaction will include cash consideration for the assets acquired by Coral as described above and liquidation of the net current assets of Avista Energy not sold to Coral (primarily receivables, restricted cash and deposits with counterparties). Over time, Avista Corp. plans to redeploy the majority of the proceeds from the transaction into its regulated utility operations by reducing debt and investing in capital assets.

For reference, the net book value of Avista Energy as shown on its balance sheet as of March 31, 2007 was $202 million.

Assets and liabilities which will be excluded from the sale and retained by Avista Energy include:

- cash,
- energy conversion, electric transmission and natural gas transportation agreements relating to a power generation facility located in Idaho after December 31, 2009,
- storage rights at a natural gas facility located in Washington after April 30, 2011,
- accounts receivable,
- certain software, hardware, licenses and permits,
- accounts payable,
- obligations related to Avista Energy's credit agreement,
- tax obligations,
- goodwill,
- litigation matters, and
- certain employment agreements and employee related obligations.

The closing of the sale is subject to customary conditions, including, but not limited to, release of all liens on the assets being acquired, the receipt of certain federal regulatory approvals (including applicable Federal Energy Regulatory Commission approvals) and the consents of parties to certain contracts to the assignment of those contracts.

At the closing of the transaction, Avista Energy and its affiliates will enter into an Indemnification Agreement with Coral and its affiliates under which Avista Energy and Coral each agree to provide indemnification of the other and the other's affiliates for certain events arising out of and matters described in the purchase and sale agreement and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the dysfunctions of western energy markets in 2000 and 2001 (see Note 25 of the Notes to Consolidated Financial Statements in Avista Corp.'s Annual Report on Form 10-K for the year ended December 31, 2006), existing litigation, environmental matters, employee-related matters, tax liabilities, matters with respect to storage rights at a natural gas storage facility located in Washington, and any potential claims associated with energy conversion, electric transmission and natural gas transportation agreements relating to a power generation facility located in Idaho. Such indemnification is generally limited to an aggregate amount of $30 million and a term of three years (except for agreements with terms longer than three years). This limitation does not apply to certain third party claims.

Avista Energy's obligations under the indemnification agreement will be guaranteed by Avista Capital up to an aggregate amount of $30 million. Avista Capital will be granting Coral a security interest in 50 percent of Avista Capital's common shares of Advantage IQ, Inc. as collateral for its guarantee. The aggregate obligations secured by this security interest will in no event exceed $25 million. This security interest will terminate 18 months after closing except to the extent of claims actually made prior to expiration of the 18-month period.

Avista Energy has made customary representations, warranties and covenants in the purchase and sale agreement. Avista Corp. and its subsidiaries have agreed that for a period of 60 calendar months beginning on the closing of the transaction, neither Avista Corp. nor any of its subsidiaries will form or participate through ownership or any alliance, or internally, develop capabilities to replicate the business activities of Avista Energy within the region of the Western Electric Coordinating Council. This restriction will not limit any resource optimization or associated trading or hedging activities of the character currently being conducted by Avista Utilities, an operating division of Avista Corp., in the ordinary course of its regulated utility business.

Subject to any extension required due to any regulatory inquiry, the closing date is expected to be late in the second quarter or early in the third quarter of 2007.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

AVISTA CORPORATION
(Registrant)

Date: April 17, 2007

/s/ Marian M. Durkin

Marian M. Durkin
Senior Vice President, General Counsel
and Chief Compliance Officer

Form 10-Q

AVISTA CORP - ava

Filed: May 04, 2007 (period: March 31, 2007)

Quarterly report which provides a continuing view of a company's financial position

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington D.C. 20549

FORM 10-Q

(Mark One)
☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2007

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ______ to ______

Commission file number 1-3701

AVISTA CORPORATION
(Exact name of registrant as specified in its charter)

Washington **(State or other jurisdiction of incorporation or organization)**	**91-0462470** **(I.R.S. Employer Identification No.)**
1411 East Mission Avenue, Spokane, Washington **(Address of principal executive offices)**	**99202-2600** **(Zip Code)**

Registrant's telephone number, including area code: 509-489-0500
Web site: http://www.avistacorp.com

None
(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act): Yes ☐ No ☒

As of April 30, 2007, 52,753,998 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

AVISTA CORPORATION

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FORWARD-LOOKING STATEMENTS

Our Quarterly Report on Form 10-Q contains forward-looking statements, which should be read with the cautionary statements and important factors included at "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Forward-Looking Statements" on pages 31-32. Forward-looking statements are all statements except those of historical fact, including, without limitation, those that are identified by the use of words that include "will," "may," "could," "should," "intends," "plans," "seeks," "anticipates," "estimates," "expects," "forecasts," "projects," "predicts," and similar expressions. All forward-looking statements are subject to a variety of risks and uncertainties and other factors. Many of these factors are beyond our control and could have a significant effect on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in our statements.

CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)
Avista Corporation

For the Three Months Ended March 31
Dollars in thousands, except per share amounts

	2007	2006
Operating Revenues:		
Utility revenues	$ 414,266	$ 423,290
Non-utility energy marketing and trading revenues	29,409	61,542
Other non-utility revenues	15,512	14,370
Total operating revenues	459,187	499,202
Operating Expenses:		
Utility operating expenses:		
Resource costs	269,986	271,605
Other operating expenses	49,041	45,727
Depreciation and amortization	21,090	20,980
Taxes other than income taxes	23,995	22,066
Non-utility operating expenses:		
Resource costs	37,727	50,127
Other operating expenses	17,136	16,311
Depreciation and amortization	1,275	1,448
Total operating expenses	420,250	428,264
Income from operations	38,937	70,938
Other Income (Expense):		
Interest expense	(20,373)	(22,145)
Interest expense to affiliated trusts	(1,810)	(1,704)
Capitalized interest	1,116	525
Other income-net	3,711	2,475
Total other income (expense)-net	(17,356)	(20,849)
Income before income taxes	21,581	50,089
Income taxes	7,487	18,517
Net income	$ 14,094	$ 31,572
Weighted-average common shares outstanding (thousands), basic	52,684	48,795
Weighted-average common shares outstanding (thousands), diluted	53,322	49,305
Total earnings per common share, basic	$ 0.27	$ 0.65
Total earnings per common share, diluted	$ 0.26	$ 0.64
Dividends paid per common share	$ 0.145	$ 0.140

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)
Avista Corporation

For the Three Months Ended March 31
Dollars in thousands

	2007	2006
Net income	$ 14,094	$ 31,572
Other Comprehensive Income (Loss):		
Foreign currency translation adjustment	114	(18)
Unrealized gains on interest rate swap agreements - net of taxes of $28 and $2,047	52	3,801
Change in unfunded benefit obligation for pension plan - net of taxes of $127	236	—
Unrealized gains on derivative commodity instruments - net of taxes of $673 and $1,103	1,249	2,049
Reclassification adjustment for realized gains on derivative commodity instruments included in net income - net of taxes of $(39) and $(335)	(73)	(623)
Unrealized investment gains - net of taxes of $2	—	4
Total other comprehensive income	1,578	5,213
Comprehensive income	$ 15,672	$ 36,785

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS
(Unaudited)
Avista Corporation

Dollars in thousands

	March 31, 2007	December 31, 2006
Assets:		
Current Assets:		
Cash and cash equivalents	$ 56,974	$ 28,242
Restricted cash	26,237	29,903
Accounts and notes receivable-less allowances of $43,014 and $42,360	258,932	286,150
Energy commodity derivative assets	—	343,726
Utility energy commodity derivative assets	19,716	10,828
Regulatory asset for utility derivatives	—	62,650
Funds held for customers	91,506	90,134
Deposits with counterparties	85,366	79,477
Materials and supplies, fuel stock and natural gas stored	19,495	42,425
Deferred income taxes	14,769	10,932
Assets held for sale	600,962	3,543
Other current assets	29,068	44,264
Total current assets	1,203,025	1,032,274
Net Utility Property:		
Utility plant in service	2,959,749	2,938,456
Construction work in progress	115,920	103,226
Total	3,075,669	3,041,682
Less: Accumulated depreciation and amortization	842,895	826,645
Total net utility property	2,232,774	2,215,037
Other Property and Investments:		
Investment in exchange power-net	30,421	31,033
Non-utility properties and investments-net	59,955	60,301
Non-current energy commodity derivative assets	—	313,300
Investment in affiliated trusts	13,403	13,403
Other property and investments-net	16,829	15,594
Total other property and investments	120,608	433,631
Deferred Charges:		
Regulatory assets for deferred income tax	104,718	105,935
Regulatory assets for pensions and other postretirement benefits	53,555	54,192
Other regulatory assets	31,578	31,752
Non-current utility energy commodity derivative assets	16,418	25,575
Power and natural gas deferrals	84,110	97,792
Unamortized debt expense	44,895	46,554
Other deferred charges	12,948	13,766
Total deferred charges	348,222	375,566
Total assets	$ 3,904,629	$ 4,056,508

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS (continued)
(Unaudited)
Avista Corporation

Dollars in thousands

	March 31, 2007	December 31, 2006
Liabilities and Stockholders' Equity:		
Current Liabilities:		
Accounts payable	$ 243,910	$ 286,099
Energy commodity derivative liabilities	—	313,499
Customer fund obligations	91,506	90,134
Deposits from counterparties	40,950	41,493
Current portion of long-term debt	14,607	26,605
Current portion of preferred stock-cumulative	26,250	26,250
Short-term borrowings	—	4,000
Interest accrued	25,468	11,595
Utility energy commodity derivative liabilities	14,658	73,478
Liabilities held for sale	574,372	—
Other current liabilities	76,365	72,056
Total current liabilities	1,108,086	945,209
Long-term debt	950,053	949,854
Long-term debt to affiliated trusts	113,403	113,403
Other Non-Current Liabilities and Deferred Credits:		
Non-current energy commodity derivative liabilities	—	309,990
Regulatory liability for utility plant retirement costs	200,665	197,712
Non-current regulatory liability for utility derivatives	11,255	15,400
Pensions and other postretirement benefits	98,239	100,033
Deferred income taxes	430,393	461,006
Other non-current liabilities and deferred credits	65,261	47,055
Total other non-current liabilities and deferred credits	805,813	1,131,196
Total liabilities	2,977,355	3,139,662
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Stockholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 52,736,534 and 52,514,326 shares outstanding	717,938	715,620
Accumulated other comprehensive loss	(16,388)	(17,966)
Retained earnings	225,724	219,192
Total stockholders' equity	927,274	916,846
Total liabilities and stockholders' equity	$ 3,904,629	$ 4,056,508

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
Avista Corporation

For the Three Months Ended March 31
Dollars in thousands

	2007	2006
Operating Activities:		
Net income	$ 14,094	$ 31,572
Non-cash items included in net income:		
Depreciation and amortization	22,365	22,428
Benefit for deferred income taxes	(11,411)	(3,301)
Power and natural gas cost amortizations, net of deferrals	14,884	19,409
Amortization of debt expense	1,704	1,917
Unrealized loss (gain) on energy commodity derivatives	20,933	(6,140)
Other	1,076	(4,768)
Changes in working capital components:		
Accounts and notes receivable	26,564	155,116
Materials and supplies, fuel stock and natural gas stored	15,062	9,447
Deposits with counterparties	(5,889)	15,223
Other current assets	13,824	(4,322)
Accounts payable	(36,877)	(167,980)
Deposits from counterparties	(543)	(3,999)
Other current liabilities	14,496	42,486
Net cash provided by operating activities	90,282	107,088
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(40,556)	(29,743)
Proceeds from sale of utility property claim	—	5,484
Other capital expenditures	(1,339)	(637)
Decrease in restricted cash	3,666	1,873
Changes in other property and investments	(1,196)	(194)
Proceeds from property sales	215	6,840
Net cash used in investing activities	(39,210)	(16,377)
Financing Activities:		
Decrease in short-term borrowings	(4,000)	(40,004)
Redemption and maturity of long-term debt	(12,255)	(421)
Cash dividends paid	(7,645)	(6,803)
Issuance of common stock	1,630	1,792
Long-term debt and short-term borrowing issuance costs	(70)	(102)
Net cash used in financing activities	(22,340)	(45,538)
Net increase in cash and cash equivalents	28,732	45,173
Cash and cash equivalents at beginning of period	28,242	25,917
Cash and cash equivalents at end of period	$ 56,974	$ 71,090
Supplemental Cash Flow Information:		
Cash paid during the period:		
Interest	$ 6,606	$ 13,536
Income taxes	—	194

The Accompanying Notes are an Integral Part of These Statements.

AVISTA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The accompanying consolidated financial statements of Avista Corporation (Avista Corp. or the Company) for the interim periods ended March 31, 2007 and 2006 are unaudited; however, in the opinion of management, the statements reflect all adjustments necessary for a fair statement of the results for the interim periods. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. The Consolidated Statements of Income for the interim periods are not necessarily indicative of the results to be expected for the full year. These consolidated financial statements do not contain the detail or footnote disclosure concerning accounting policies and other matters which would be included in full fiscal year consolidated financial statements; therefore, they should be read in conjunction with the Company's audited consolidated financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2006 (2006 Form 10-K). Please refer to the section "Acronyms and Terms" in the 2006 Form 10-K for definitions of terms such as capacity, energy and therm.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corp. is an energy company engaged in the generation, transmission and distribution of energy as well as other energy-related businesses. Avista Utilities is an operating division of Avista Corp., comprising the regulated utility operations. Avista Utilities generates, transmits and distributes electricity in parts of eastern Washington and northern Idaho. In addition, Avista Utilities has electric generating facilities in western Montana and northern Oregon. Avista Utilities also provides natural gas distribution service in parts of eastern Washington and northern Idaho, as well as parts of northeast and southwest Oregon. Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility business segments, including Avista Energy, Inc. (Avista Energy) and Advantage IQ, Inc. (Advantage IQ). Avista Energy is an electricity and natural gas marketing, trading and resource management business. Advantage IQ is a provider of facility information and cost management services for multi-site customers throughout North America. See Note 14 for business segment information.

The Company's operations are exposed to risks including, but not limited to:

- price and supply of purchased power, fuel and natural gas,
- regulatory recovery of power and natural gas costs and capital investments,
- streamflow and weather conditions,
- effects of changes in legislative and governmental regulations,
- changes in regulatory requirements,
- availability of generation facilities,
- competition,
- technology, and
- availability of funding.

Also, like other utilities, the Company's facilities and operations are exposed to terrorism risks or other malicious acts. In addition, the energy business exposes the Company to the financial, liquidity, credit and price risks associated with wholesale purchases and sales of energy commodities.

Basis of Reporting

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries, including variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. All significant intercompany balances have been eliminated in consolidation. The accompanying financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants.

Use of Estimates

The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Significant estimates include:

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,

- contingent liabilities,
- recoverability of regulatory assets,
- stock-based compensation, and
- unbilled revenues.

Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on the consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein.

Utility Revenues

Utility revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. The determination of the energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, the amount of energy delivered to customers since the date of the last meter reading is estimated and the corresponding unbilled revenue is estimated and recorded. Revenues and resource costs from Avista Utilities' settled energy contracts that are "booked out" (not physically delivered) are reported on a net basis as part of utility revenues.

Non-Utility Energy Marketing and Trading Revenues

Avista Energy follows Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, for the majority of its contracts. Avista Energy reports the net margin on derivative commodity instruments held for trading as non-utility energy marketing and trading revenues. Revenues from contracts that are not derivatives under SFAS No. 133, as well as derivative commodity instruments not held for trading, are reported on a gross basis in non-utility energy marketing and trading revenues. Revenues from Canadian contracts through Avista Energy Canada, Ltd. (Avista Energy Canada), which are not held for trading and are reported on a gross basis in non-utility energy marketing and trading revenues, were $38.6 million for the three months ended March 31, 2007 and $42.8 million for the three months ended March 31, 2006. On April 16, 2007, Avista Energy and Avista Energy Canada entered into a purchase and sale agreement to sell substantially all of their contracts and ongoing operations. See Note 3 for further information.

Other Non-Utility Revenues

Service revenues from Advantage IQ are recognized in the period services are rendered. Setup fees are deferred and recognized over the term of the related customer contracts. Interest earnings on funds held for customers are an integral part of Advantage IQ's product offerings and are recognized in revenues as earned. Revenues in the other business segment are primarily derived from the operations of Advanced Manufacturing and Development and are recognized when the risk of loss transfers to the customer, which generally occurs when products are shipped.

Other Income-Net

Other income-net consisted of the following items for the three months ended March 31 (dollars in thousands):

	2007	2006
Interest income	$ 2,474	$ 1,903
Interest on power and natural gas deferrals	1,203	1,907
Net gain (loss) on investments	444	(433)
Other expense	(1,424)	(1,488)
Other income	1,014	586
Total	$ 3,711	$ 2,475

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss), net of tax, consisted of the following as of March 31, 2007 and December 31, 2006 (dollars in thousands):

	March 31, 2007	December 31, 2006
Foreign currency translation adjustment	$ 1,483	$ 1,369
Unfunded benefit obligation for the pension plan	(15,746)	(15,982)
Unrealized loss on interest rate swap agreements	(3,294)	(3,346)
Unrealized gain (loss) on derivative commodity instruments	1,169	(7)
Total accumulated other comprehensive loss	$ (16,388)	$ (17,966)

Assets Held for Sale

Assets held for sale are recorded at the lower of their carrying amount or fair value less cost to sell. As of March 31, 2007, assets held for sale included $597.5 million of assets from Avista Energy (including energy commodity derivative assets, natural gas inventory, goodwill and certain fixed assets; see Note 3 for further information), as well as $3.5 million of turbines and related equipment at Avista Utilities. As of December 31, 2006, assets held for sale included $3.5 million of turbines and related equipment at Avista Utilities. Liabilities held for sale of $574.4 million as of March 31, 2007 represent energy commodity derivative liabilities at Avista Energy. There were not any liabilities held for sale as of December 31, 2006.

Regulatory Deferred Charges and Credits

The Company prepares its consolidated financial statements in accordance with the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." The Company prepares its financial statements in accordance with SFAS No. 71 because:

- rates for regulated services are established by or subject to approval by an independent third-party regulator,
- the regulated rates are designed to recover the cost of providing the regulated services, and
- in view of demand for the regulated services and the level of competition, it is reasonable to assume that rates can be charged to and collected from customers at levels that will recover costs.

SFAS No. 71 requires the Company to reflect the impact of regulatory decisions in its financial statements. SFAS No. 71 requires that certain costs and/or obligations (such as incurred power and natural gas costs not currently recovered through rates, but expected to be recovered in the future) are reflected as deferred charges or credits on the Consolidated Balance Sheets. These costs and/or obligations are not reflected in the statement of income until the period during which matching revenues are recognized.

If at some point in the future the Company determines that it no longer meets the criteria for continued application of SFAS No. 71 for all or a portion of its regulated operations, the Company could be:

- required to write off its regulatory assets, and
- precluded from the future deferral of costs not recovered through rates at the time such costs are incurred, even if the Company expected to recover such costs in the future.

The Company's primary regulatory assets include:

- power and natural gas deferrals,
- investment in exchange power,
- regulatory asset for deferred income taxes,
- unamortized debt expense,
- demand side management programs,
- conservation programs, and
- unfunded pensions and other postretirement benefits.

Those items without a specific line on the Consolidated Balance Sheets are included in other regulatory assets.

Regulatory liabilities include:

- utility plant retirement costs,
- liabilities created when the Centralia Power Plant was sold,
- liabilities offsetting net utility energy commodity derivative assets (see Note 5 for further information), and
- the gain on the general office building sale/leaseback.

Those items without a specific line on the Consolidated Balance Sheets are included in other current liabilities and other non-current liabilities and deferred credits.

Reclassifications

Certain prior period amounts were reclassified to conform to current statement format. These reclassifications were made for comparative purposes and have not affected previously reported total net income or stockholders' equity.

NOTE 2. NEW ACCOUNTING STANDARDS

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109," (FIN 48) which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires the evaluation of a tax position as a two-step process. First, the Company is required to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If the tax position meets the "more likely than not" recognition threshold, it is then measured and recorded at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. The Company adopted FIN 48 in the first quarter of 2007 (effective January 1, 2007). The adoption of FIN 48 did not have a cumulative effect on the Company's financial condition and results of operations. See Note 8 for further information.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which provides enhanced guidance for using fair value to measure assets and liabilities. This statement also expands disclosures about fair value measurements. This statement applies under other accounting pronouncements that require or permit fair value measurements. However, the statement does not require any new fair value measurements. This statement emphasizes that fair value is a market-based measurement and not an entity-specific measurement. Therefore a fair value measurement should be determined based on the assumptions that market participants would use in pricing an asset or liability. The statement establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data. The Company will be required to adopt SFAS No. 157 in 2008. The Company is evaluating the impact SFAS No. 157 will have on its financial condition and results of operations.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." This statement permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected would be reported in net income. The Company will be required to adopt SFAS No. 159 in 2008. The Company is evaluating the impact SFAS No. 159 will have on its financial condition and results of operations.

NOTE 3. DISPOSITION OF AVISTA ENERGY

On April 16, 2007, Avista Energy and Avista Energy Canada entered into a purchase and sale agreement with Coral Energy Holding, L.P. (Coral Energy), a subsidiary of the Shell Group of Companies, as well as certain other subsidiaries of Coral Energy. Pursuant to the agreement, Avista Energy will sell substantially all of its contracts and ongoing operations to Coral Energy and Avista Energy Canada will sell substantially all of its contracts and ongoing operations to Coral Energy Canada Inc., a subsidiary of Coral Energy.

Avista Corp. explored whether it should continue in this business over the long term or if any strategic alternatives were available. Energy commodity derivative assets, natural gas inventory and certain other assets of Avista Energy are accounted for as held for sale as of March 31, 2007 because the decision to sell these assets was made prior to that date. Until the transaction is completed, Avista Energy's results of operations will continue to be reflected in Avista Corp.'s consolidated financial statements.

The transaction will be completed through the purchase and sale agreement and certain other ancillary agreements. As consideration for the assets acquired (net of liabilities assumed), the purchase price to be paid by Coral Energy will be calculated on the closing date as the sum of the following (subject to certain adjustments):

- the net trade book value of contracts acquired,
- the market value of the natural gas inventory, and
- the net book value of the tangible fixed assets acquired.

After closing costs and other adjustments, the transaction is not expected to result in a significant gain or loss for Avista Corp. This expectation could change due to several factors including, but not limited to, changes in the market value of natural gas inventory and certain other contracts and changes in the estimate of transaction costs and other costs associated with closing out Avista Energy's operations. Proceeds from the transaction will include cash consideration for the net assets acquired by Coral Energy as described above and liquidation of the net current assets of Avista Energy not sold to Coral Energy (primarily receivables, restricted cash and deposits with counterparties). Over time, Avista Corp. plans to redeploy the majority of the proceeds from the transaction into its regulated utility operations by reducing debt and investing in capital assets. For reference, the net book value of Avista Energy as shown on its balance sheet as of March 31, 2007 was $202 million.

Avista Energy's assets held for sale consisted of the following as of March 31, 2007 (dollars in thousands):

Energy commodity derivative assets	$ 588,784
Natural gas inventory	7,868
Goodwill	1,009
Fixed assets	336
Adjustment to estimated fair value less selling costs	(494)
Total assets held for sale of Avista Energy	$ 597,503

Liabilities held for sale of $574.4 million consisted of energy commodity derivative liabilities.

Assets and liabilities which will be excluded from the sale and retained by Avista Energy include:

- cash,
- certain agreements related to a power generation facility located in Idaho after December 31, 2009,
- storage rights at a natural gas facility located in Washington after April 30, 2011,
- accounts receivable,
- certain software, hardware, licenses and permits,
- accounts payable,
- obligations related to Avista Energy's credit agreement,
- tax obligations,
- cash deposits with and from counterparties,
- litigation matters (including matters related to western energy markets), and
- certain employment agreements and employee related obligations.

At the closing of the transaction, Avista Energy and its affiliates will enter into an Indemnification Agreement with Coral Energy and its affiliates under which Avista Energy and Coral Energy each agree to provide indemnification of the other and the other's affiliates for certain events arising out of and matters described in the purchase and sale agreement and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the dysfunctions of western energy markets in 2000 and 2001 (see Note 12), existing litigation, environmental matters, employee-related matters, tax liabilities, matters with respect to storage rights at a natural gas storage facility located in Washington, and any potential claims associated with energy conversion, electric transmission and natural gas transportation agreements relating to a power generation facility located in Idaho. Such indemnification is generally limited to an aggregate amount of $30 million and a term of three years (except for agreements with terms longer than three years). This limitation does not apply to certain third party claims.

Avista Energy's obligations under the indemnification agreement will be guaranteed by Avista Capital up to an aggregate amount of $30 million. Avista Capital will be granting Coral Energy a security interest in 50 percent of Avista Capital's common shares of Advantage IQ as collateral for its guarantee. The aggregate obligations secured by this security interest will in no event exceed $25 million. This security interest will terminate 18 months after closing except to the extent of claims actually made prior to expiration of the 18-month period.

Avista Energy has made customary representations, warranties and covenants in the purchase and sale agreement. Avista Corp. and its subsidiaries have agreed that for a period of 60 calendar months beginning on the closing of the transaction, neither Avista Corp. nor any of its subsidiaries will form or participate through ownership or any alliance, or internally, develop capabilities to replicate the business activities of Avista Energy within the region of the Western Electric Coordinating Council. This restriction has certain exceptions primarily related to any assets or contracts retained by Avista Energy and any current corporate activities outside of Avista Energy, including any resource optimization or associated trading or hedging activities of the character currently being conducted by Avista Utilities, an operating division of Avista Corp., in the ordinary course of its regulated utility business (see Notes 5 and 6).

The closing of the sale is subject to customary conditions including, but not limited to, release of all liens on the assets being acquired, the receipt of certain regulatory approvals (including applicable Federal Energy Regulatory Commission approvals) and the consents of parties to certain contracts to the assignment of those contracts. The closing date is expected to be late in the second quarter or early in the third quarter of 2007.

NOTE 4. ACCOUNTS RECEIVABLE SALE

Avista Receivables Corporation (ARC) is a wholly owned, bankruptcy-remote subsidiary of Avista Corp., formed for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. On March 19, 2007, Avista Corp., ARC and a third-party financial institution amended a Receivables Purchase Agreement. The most significant amendment was to extend the termination date from March 20, 2007 to March 17, 2008. Under the Receivables Purchase Agreement, ARC can sell without recourse, on a revolving basis, up to $85.0 million of those receivables. ARC is obligated to pay fees that approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. On a consolidated basis, the amount of such fees is included in other operating expenses of Avista Corp. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of Avista Corp.'s $320.0 million committed line of credit (see Note 9). As of March 31, 2007, $68.0 million in accounts receivables were sold under this revolving agreement, a decrease from $85.0 million as of December 31, 2006.

NOTE 5. UTILITY ENERGY COMMODITY DERIVATIVE ASSETS AND LIABILITIES

SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It requires the recording of all derivatives as either assets or liabilities on the balance sheet measured at estimated fair value and the recognition of the unrealized gains and losses. In certain defined conditions, a derivative may be specifically designated as a hedge for a particular exposure. The accounting for derivatives depends on the intended use of the derivatives and the resulting designation.

Avista Utilities enters into forward contracts to purchase or sell electricity and natural gas. Under these forward contracts, Avista Utilities commits to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. Certain of these forward contracts are considered derivative instruments. Avista Utilities also records derivative commodity assets and liabilities for over-the-counter and exchange-traded derivative instruments as well as certain long-term contracts. These contracts are entered into as part of Avista Utilities' management of its loads and resources as discussed in Note 6. In conjunction with the issuance of SFAS No. 133, the Washington Utilities and Transportation Commission (WUTC) and the Idaho Public Utilities Commission (IPUC) issued accounting orders authorizing Avista Utilities to offset any derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The orders provide for Avista Utilities to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Consolidated Statements of Income. Realized gains and losses are recognized in the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the Energy Recovery Mechanism in Washington and the Power Cost Adjustment mechanism in Idaho.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as assets or liabilities at estimated fair value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives under SFAS No. 133 are generally accounted for at cost until they are settled or realized, unless there is a decline in the fair value of the contract that is determined to be other than temporary.

Utility energy commodity derivatives consisted of the following as of March 31, 2007 and December 31, 2006 (dollars in thousands):

	March 31, 2007	December 31, 2006
Current utility energy commodity derivative assets	$ 19,716	$ 10,828
Current utility energy commodity derivative liabilities	(14,658)	(73,478)
Net current regulatory liability (asset)	$ 5,058	$ (62,650)
Non-current utility energy commodity derivative assets	$ 16,418	$ 25,575
Non-current utility energy commodity derivative liabilities	(5,163)	(10,175)
Net non-current regulatory liability	$ 11,255	$ 15,400

The net current regulatory liability as of March 31, 2007 is included in other current liabilities on the Consolidated Balance Sheet. Non-current utility energy commodity derivative liabilities are included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets.

NOTE 6. ENERGY COMMODITY TRADING

The Company’s energy-related businesses are exposed to risks relating to, but not limited to:

- changes in certain commodity prices,
- interest rates,
- foreign currency, and
- counterparty performance.

Avista Utilities utilizes derivative instruments, such as forwards, futures, swaps and options in order to manage the various risks relating to these exposures, and Avista Energy engages in the trading of such instruments. Avista Utilities and Avista Energy use a variety of techniques to manage risks for their energy resources and wholesale energy market activities. The Company has risk management policies and procedures to manage these risks, both qualitative and quantitative, for Avista Utilities and Avista Energy. The Company’s Risk Management Committee establishes the Company’s risk management policies and procedures and monitors compliance. The Risk Management Committee is comprised of certain Company officers and other individuals and is overseen by the Audit Committee of the Company’s Board of Directors.

Avista Utilities

Avista Utilities engages in an ongoing process of resource optimization, which involves the economic selection from available resources to serve Avista Utilities’ load obligations and uses its existing resources to capture available economic value. Avista Utilities sells and purchases wholesale electric capacity and energy and fuel as part of the process of acquiring resources to serve its load obligations. These transactions range from terms of one hour up to multiple years. Avista Utilities makes continuing projections of:

- loads at various points in time (ranging from one hour to multiple years) based on, among other things, estimates of factors such as customer usage and weather, as well as historical data and contract terms, and
- resource availability at these points in time based on, among other things, estimates of streamflows, availability of generating units, historic and forward market information and experience.

On the basis of these projections, Avista Utilities makes purchases and sales of energy to match expected resources to expected electric load requirements. Resource optimization involves generating plant dispatch and scheduling available resources and also includes transactions such as:

- purchasing fuel for generation,
- when economic, selling fuel and substituting wholesale purchases for the operation of Avista Utilities’ resources, and
- other wholesale transactions to capture the value of generation and transmission resources.

Avista Utilities’ optimization process includes entering into hedging transactions to manage risks.

As part of its resource optimization process described above, Avista Utilities manages the impact of fluctuations in electric energy prices by measuring and controlling the volume of energy imbalance between projected loads and resources and through the use of derivative commodity instruments for hedging purposes. Load/resource imbalances within a rolling 18-month planning horizon are compared against established volumetric guidelines and management determines the timing and specific actions to manage the imbalances. Management also assesses available resource decisions and actions that are appropriate for longer-term planning periods.

Avista Energy

As disclosed in Note 3, Avista Energy and Avista Energy Canada entered into a purchase and sale agreement to sell substantially all of their contracts and ongoing operations. Until the transaction is completed, Avista Energy’s results of operations will continue to be reflected in Avista Corp’s consolidated financial statements.

Avista Energy has implemented hedge accounting in accordance with SFAS No. 133. Specific natural gas and electric trading derivative contracts have been designated as hedging instruments in cash flow hedging relationships. The hedge strategies represent cash flow hedges of the variable price risk associated with expected purchases of natural gas and sales of electricity. These designated hedging instruments represent hedges of variable price exposures generated from certain contracts, which do not qualify as derivatives under SFAS No. 133. For all derivatives designated as cash flow hedges, Avista Energy documents the:

- relationship between the hedging instrument and the hedged item (forecasted purchases and sales of power and natural gas), and
- risk management objective and strategy for using the hedging instrument.

AVISTA CORPORATION

Avista Energy assesses whether a change in the value of the designated derivative is highly effective in achieving offsetting cash flows attributable to the hedged item, both at the inception of the hedge and on an ongoing basis. Any changes in the fair value of the designated derivative that are effective are recorded in accumulated other comprehensive income or loss, while changes in fair value that are not effective are recognized currently in earnings as operating revenues. Amounts recorded in accumulated other comprehensive income or loss are recognized in earnings during the period that the hedged items are recognized in earnings. The following table presents activity related to Avista Energy's hedge accounting during the three months ended March 31 (dollars in thousands):

	2007	2006
Gain related to hedge ineffectiveness recorded in operating revenues	$ 510	$ —
Gain reclassified from accumulated other comprehensive income (loss) and recognized in earnings (pre-tax)	112	958

The following table presents the net gain (loss), net of tax, related to Avista Energy's cash flow hedges as of March 31, 2007 and December 31, 2006 (dollars in thousands):

	March 31, 2007	December 31, 2006
Accumulated other comprehensive income related to natural gas derivatives	$ 2,929	$ 272
Accumulated other comprehensive loss related to electric derivatives	(1,760)	(279)
Total accumulated other comprehensive income (loss)	$ 1,169	$ (7)

Avista Energy expects to recognize a gain of $0.8 million in earnings during the next 12 months, related to amounts currently in accumulated other comprehensive income. The actual amounts that will be recognized in Avista Energy's earnings during the next 12 months will vary from the expected amounts as a result of changes in market prices. The maximum term of the designated hedging instruments is 12 months.

Contract Amounts and Terms Under Avista Energy's derivative instruments, Avista Energy either (i) as "fixed price payor," is obligated to pay a fixed price or a fixed amount and is entitled to receive the commodity or a fixed amount, (ii) as "fixed price receiver," is entitled to receive a fixed price or a fixed amount and is obligated to deliver the commodity or pay a fixed amount, (iii) as "index price payor," is obligated to pay an indexed price or an indexed amount and is entitled to receive the commodity or a variable amount or (iv) as "index price receiver," is entitled to receive an indexed price or amount and is obligated to deliver the commodity or pay a variable amount. The contract or notional amounts and terms of Avista Energy's derivative commodity instruments outstanding as of March 31, 2007 are set forth below (in thousands of MWhs and mmBTUs):

	Fixed Price Payor	Fixed Price Receiver	Maximum Terms in Years	Index Price Payor	Index Price Receiver	Maximum Terms in Years
Energy commodities (volumes)						
Electric	26,083	27,988	10	7,357	6,584	3
Natural gas	104,542	90,409	5	531,191	549,378	5

The weighted average term of Avista Energy's electric derivative commodity instruments as of March 31, 2007 was approximately 6 months. The weighted average term of Avista Energy's natural gas derivative commodity instruments as of March 31, 2007 was approximately 5 months.

Estimated Fair Value The estimated fair value of Avista Energy's derivative commodity instruments outstanding as of March 31, 2007 (all of which are classified as assets and liabilities held for sale), and the average estimated fair value of those instruments held during the year ended March 31, 2007, are set forth below (dollars in thousands):

	Estimated Fair Value as of March 31, 2007				Average Estimated Fair Value for the three months ended March 31, 2007			
	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities
Electric	$ 212,878	$ 300,721	$ 200,922	$ 295,468	$ 180,516	$ 290,271	$ 162,253	$ 283,309
Natural gas	60,804	14,381	64,640	13,341	108,728	17,207	110,269	20,166
Total	$ 273,682	$ 315,102	$ 265,562	$ 308,809	$ 289,244	$ 307,478	$ 272,522	$ 303,475

The change in the estimated fair value position of Avista Energy's energy commodity portfolio, net of reserves for credit and market risk for the three months ended March 31, 2007 was an unrealized loss of $20.9 million and is included in the Consolidated Statements of Income in non-utility energy marketing and trading revenues. The change in the fair value position for the three months ended March 31, 2006 was an unrealized gain of $6.1 million.

NOTE 7. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering substantially all regular full-time employees at Avista Utilities and Avista Energy. Individual benefits under this plan are based upon the employee's years of service and average compensation as specified in the plan. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company made $15 million in cash contributions to the pension plan in 2006 and expects to contribute $15 million to the pension plan in 2007.

The Company also has a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to executive officers of the Company. The SERP is intended to provide benefits to executive officers whose benefits under the pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans.

The Company provides certain health care and life insurance benefits for substantially all of its retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services.

The Company established a Health Reimbursement Arrangement to provide employees with tax-advantaged funds to pay for allowable medical expenses upon retirement. The amount earned by the employee is fixed on the retirement date based on employees' years of service and the ending salary. The liability and expense of this plan are included as other postretirement benefits.

The Company uses a December 31 measurement date for its pension and postretirement plans. The following table sets forth the components of net periodic benefit costs for the three months ended March 31 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2007	2006	2007	2006
Service cost	$ 2,740	$ 2,495	$ 136	$ 175
Interest cost	4,766	4,231	439	416
Expected return on plan assets	(4,802)	(4,236)	(391)	(342)
Transition obligation recognition	—	—	126	126
Amortization of prior service cost	164	164	—	—
Net loss recognition	769	847	57	86
Net periodic benefit cost	$ 3,637	$ 3,501	$ 367	$ 461

NOTE 8. ACCOUNTING FOR INCOME TAXES

As disclosed in Note 2, the Company adopted FIN 48 during the first quarter of 2007 (effective January 1, 2007), which did not have a cumulative effect on the Company's financial condition and results of operations.

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon, Montana and California. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The Internal Revenue Service (IRS) has examined the Company's 2001, 2002 and 2003 federal income tax returns. Despite those tax years still remaining open, all issues have been resolved with the exception of certain indirect overhead costs. The IRS is currently conducting an examination of the Company's 2004 and 2005 federal income tax returns. This examination could result in a change in the liability for uncertain tax positions. However, an estimate of the range of any such possible change cannot be made at this time. The Company does not believe that any open tax years with respect to state income taxes could result in any adjustments that would be significant to the consolidated financial statements.

In August 2005, the Treasury Department issued regulations and the IRS issued a revenue ruling that affect the tax treatment by Avista Corp. of certain indirect overhead expenses. Avista Corp. had previously made a tax election to currently deduct certain indirect overhead costs, starting with the 2002 tax return, that were capitalized for financial accounting purposes. This election allowed Avista Corp. to take tax deductions resulting in a total reduction of approximately $40 million in current tax liabilities for 2002, 2003 and 2004. These current tax benefits were deferred on the balance sheet in accordance with provisions of SFAS No. 109 and did not affect net income.

Due to the revenue ruling and related regulations, the IRS has disallowed the tax deduction of indirect overhead expenses during their exam of the Company's 2001, 2002 and 2003 federal income tax returns. The Company believes that the tax deductions claimed on tax returns were appropriate based on the applicable statutes and regulations in effect at the time. Avista Corp. appealed the proposed IRS adjustment on April 19, 2006. The Company's appeal has been received, but has not yet been scheduled for review by the IRS Appeals Division. The Company repaid a portion of the previous tax deductions through tax payments in 2005 and 2006. There can be no assurance that the Company's position will prevail. However, it is not expected to have a significant effect on the Company's net income.

The Company estimates that its liability for unrecognized tax benefits is $22.6 million at each of January 1, 2007 and March 31, 2007. With the adoption of FIN 48, this amount was reclassified from deferred income taxes to liability for unrecognized tax benefits. This liability primarily relates to the indirect overhead expenses described above, and the amount of this liability is included as other non-current liabilities and deferred credits on the Consolidated Balance Sheet as of March 31, 2007. The liability for unrecognized tax benefits would not affect the tax rate if recognized in 2007 as any adjustment to this tax item would be offset by an adjustment to current income tax expense. The liability for interest expense for unrecognized tax benefits as of January 1, 2007 was not material due to net operating loss and tax credit carryovers. The change in the liability for interest expense during the three months ended March 31, 2007 was not material. The Company has not accrued any penalties. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operating expense.

NOTE 9. SHORT-TERM BORROWINGS

The Company has a committed line of credit agreement with various banks in the total amount of $320.0 million with an expiration date of April 5, 2011. Under the credit agreement, the Company can request the issuance of up to $320.0 million in letters of credit. The Company did not have any borrowings outstanding as of March 31, 2007 and $4.0 million of borrowings outstanding as of December 31, 2006. Total letters of credit outstanding were $45.3 million as of March 31, 2007 and $77.1 million as of December 31, 2006. The committed line of credit is secured by $320.0 million of non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions, including a covenant requiring the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Utilities for the preceding twelve-month period at the end of any fiscal quarter to be greater than 1.6 to 1. As of March 31, 2007, the Company was in compliance with this covenant with a ratio of 2.45 to 1. The committed line of credit agreement also has a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 70 percent at the end of any fiscal quarter. This ratio limitation will be increased to 75 percent during the period between the completion of the proposed change in the Company's corporate organization (see Note 13) and December 31, 2007. As of March 31, 2007, the Company was in compliance with this covenant with a ratio of 53.1 percent. If the proposed change in organization becomes effective, the committed line of credit agreement will remain at Avista Corp.

Avista Energy and its subsidiary, Avista Energy Canada, as co-borrowers, have a committed credit agreement with a group of banks in the aggregate amount of $145.0 million with an expiration date of July 12, 2007. The Company expects that the Avista Energy credit agreement will be extended if necessary and terminated with the closing of the sale of Avista Energy's contracts and ongoing operations (see Note 3). This committed credit facility provides for the issuance of letters of credit to secure contractual obligations to counterparties and for cash advances. This facility is secured by the assets of Avista Energy and Avista Energy Canada and guaranteed by Avista Capital and by CoPac Management, Inc., a wholly owned subsidiary of Avista Energy Canada. The maximum amount of credit extended by the banks for the issuance of letters of credit is the subscribed amount of the facility less the amount of outstanding cash advances, if any. The maximum amount available for cash advances under the credit agreement is $50.0 million. No cash advances were outstanding as of March 31, 2007 and December 31, 2006. The total aggregate amount of letters of credit outstanding was $20.6 million as of March 31, 2007 and $52.5 million as of December 31, 2006. The cash deposits of Avista Energy at the respective banks collateralized $20.6 million and $24.9 million of these letters of credit as of March 31, 2007 and December 31, 2006, which is reflected as restricted cash on the Consolidated Balance Sheets.

The Avista Energy credit agreement contains covenants and default provisions, including covenants to maintain "minimum net working capital" and "minimum net worth," as well as a covenant limiting the amount of indebtedness that the co-borrowers may incur. The credit agreement also contains covenants and other restrictions related to the co-borrowers' trading limits and positions, including VAR limits, restrictions with respect to changes in risk management policies or volumetric limits, and limits on exposure related to hourly and daily trading of electricity. These covenants, certain counterparty agreements and market liquidity conditions result in Avista Energy maintaining certain levels of cash and therefore effectively limit the amount of cash dividends that are available for distribution to Avista Capital and ultimately to Avista Corp. Avista Energy was in compliance with the covenants of its credit agreement as of March 31, 2007.

NOTE 10. LONG-TERM DEBT

The following details the interest rate and maturity dates of long-term debt outstanding as of March 31, 2007 and December 31, 2006 (dollars in thousands):

Maturity Year	Description	Interest Rate	March 31, 2007	December 31, 2006
2007	Secured Medium-Term Notes	5.99%	$ 13,850	$ 13,850
2008	Secured Medium-Term Notes	6.06%-6.95%	45,000	45,000
2010	Secured Medium-Term Notes	6.67%-8.02%	35,000	35,000
2012	Secured Medium-Term Notes	7.37%	7,000	7,000
2013	First Mortgage Bonds	6.13%	45,000	45,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Pollution Control Bonds	5.00%	66,700	66,700
2034	Pollution Control Bonds	5.13%	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
	Total secured long-term debt		680,550	680,550
2007	Unsecured Medium-Term Notes	7.90%-7.94%	—	12,000
2008	Unsecured Senior Notes	9.75%	272,860	272,860
2023	Pollution Control Bonds	6.00%	4,100	4,100
	Total unsecured long-term debt		276,960	288,960
	Other long-term debt and capital leases		7,458	7,364
	Interest rate swaps		1,051	1,037
	Unamortized debt discount		(1,359)	(1,452)
	Total		964,660	976,459
	Current portion of long-term debt		(14,607)	(26,605)
	Total long-term debt		$ 950,053	$ 949,854

NOTE 11. EARNINGS PER COMMON SHARE

The following table presents the computation of basic and diluted earnings per common share for the three months ended March 31 (in thousands, except per share amounts):

	2007	2006
Numerator:		
Net income	$ 14,094	$ 31,572
Denominator:		
Weighted-average number of common shares outstanding-basic	52,684	48,795
Effect of dilutive securities:		
Contingent stock awards	275	212
Stock options	363	298
Weighted-average number of common shares outstanding-diluted	53,322	49,305
Total earnings per common share, basic	$ 0.27	$ 0.65
Total earnings per common share, diluted	$ 0.26	$ 0.64

Total stock options outstanding that were not included in the calculation of diluted earnings per common share were 26,200 for the three months ended March 31, 2007 and 446,500 for the three months ended March 31, 2006. These stock options were excluded from the calculation because they were antidilutive based on the fact that the exercise price of the stock options was higher than the average market price of Avista Corp. common stock during the respective period.

NOTE 12. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. With respect to these proceedings, the Company intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. With respect to matters that affect Avista Utilities' operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the rate making process. With respect to matters discussed in this Note that affect Avista Energy (particularly the California Refund Proceeding), any potential liabilities or refunds will remain at Avista Corp. and/or its subsidiaries and will not be assumed by Coral Energy and/or its affiliates.

Federal Energy Regulatory Commission Inquiry

On April 19, 2004, the FERC issued an order approving the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) reached by Avista Corp. doing business as Avista Utilities, Avista Energy and the FERC's Trial Staff with respect to an investigation into the activities of Avista Utilities and Avista Energy in western energy markets during 2000 and 2001. In the Agreement in Resolution, the FERC Trial Staff stated that its investigation found: (1) no evidence that any executives or employees of Avista Utilities or Avista Energy knowingly engaged in or facilitated any improper trading strategy; (2) no evidence that Avista Utilities or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; and (3) that Avista Utilities and Avista Energy did not withhold relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001. In April 2005 and June 2005, the California Parties and the City of Tacoma, respectively, filed petitions for review of the FERC's decisions approving the Agreement in Resolution with the United States Court of Appeals for the Ninth Circuit. Based on the FERC's order approving the Agreement in Resolution and the FERC's denial of rehearing requests, the Company does not expect that this proceeding will have any material adverse effect on its financial condition, results of operations or cash flows.

Class Action Securities Litigation

On November 10, 2005, an amended class action complaint was filed in the United States District Court for the Eastern District of Washington against Avista Corp., Thomas M. Matthews, the former Chairman of the Board, President and Chief Executive Officer of Avista Corp., Gary G. Ely, the current Chairman of the Board and Chief Executive Officer of Avista Corp., and Jon E. Eliassen, the former Senior Vice President and Chief Financial Officer of Avista Corp. Several class action complaints were originally filed in September through November 2002 in the same court against the same parties. In February 2003, the court issued an order, which consolidated the complaints and in August 2003, the plaintiffs filed a consolidated amended class action complaint. On June 13, 2005, the Company filed a motion for reconsideration of its earlier motion to dismiss this complaint, based, in part, on a recent United States Supreme Court decision with respect to the pleading requirements surrounding a sufficient showing of loss causation. On October 19, 2005, the Court granted the Company's motion to dismiss this complaint. The order to dismiss was issued without prejudice, which allowed the plaintiffs to amend their complaint. The amended complaint filed on November 10, 2005 alleges damages due to the decrease in the total market value of the Company's common stock during the class period, alleged to be approximately $2.6 billion. These alleged losses stemmed from alleged violations of federal securities laws through alleged misstatements and omissions of material facts with respect to the Company's energy trading practices in western power markets. The plaintiffs assert that alleged misstatements and omissions regarding these matters were made in the Company's filings with the Securities and Exchange Commission and other information made publicly available by the Company, including press releases. The class action complaint asserts claims on behalf of all persons who purchased, converted, exchanged or otherwise acquired the Company's common stock during the period between November 23, 1999 and August 13, 2002. On January 6, 2006, the Company filed a motion to dismiss the November 10, 2005 complaint, asserting deficiencies in the amended complaint, including that the plaintiffs failed to adequately allege loss causation. On June 2, 2006, the U.S. District Court entered an order denying the Company's motion to dismiss the complaint. The U.S. District Court's order denying the Company's motion to dismiss is not a decision on the merits of the lawsuit. On September 16, 2006, the plaintiffs filed a motion for class certification. On February 13, 2007, the plaintiffs' motion for class certification was heard before the court. Also, pending before the court is defendants' motion for summary judgment seeking to dismiss plaintiffs' claims on the ground that they are barred by the applicable statute of limitations.

Because the resolution of this lawsuit remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect that this lawsuit will have a material adverse effect on its financial condition, results of operations or cash flows.

California Refund Proceeding

With respect to Avista Energy, any potential liabilities or refunds regarding this proceeding will remain at Avista Corp. and/or its subsidiaries and will not be assumed by Coral Energy and/or its affiliates.

In July 2001, the FERC ordered an evidentiary hearing to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX) during the period from October 2, 2000 to June 20, 2001 (Refund Period) in the California spot power market. The findings of the FERC administrative law judge were largely adopted in March 2003 by the FERC. The refunds ordered are based on the development of a mitigated market clearing price methodology. If the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, the FERC has held that the seller would be allowed to document these costs and limit its refund liability commensurately. In September 2005, Avista Energy submitted its cost filing claim pursuant to the FERC's August 2005 order and demonstrated an overall revenue shortfall for sales into the California spot markets during the Refund Period after the mitigated market clearing price methodology is applied to its transactions. That filing was accepted in orders issued by the FERC in January 2006 and November 2006. In April 2007, the CalISO filed a status report with the FERC stating that it will take approximately seven weeks to complete the financial adjustment phase calculations for the Refund Period. In January 2007, Avista Energy joined in a settlement filed with the FERC by participants in markets operated by the Automated Power Exchange. The settlement was approved in March 2007.

In 2001, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) defaulted on payment obligations to the CalPX and the CalISO. As a result, the CalPX and the CalISO failed to pay various energy sellers, including Avista Energy. Both PG&E and the CalPX declared bankruptcy in 2001. In March 2002, SCE paid its defaulted obligations to the CalPX. In April 2004, PG&E paid its defaulted obligations into an escrow fund in accordance with its bankruptcy reorganization. Funds held by the CalPX and in the PG&E escrow fund are not subject to release until the FERC issues an order directing such release in the California refund proceeding. As of March 31, 2007, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from defaulting parties.

In addition, in June 2003, the FERC issued an order to review bids above $250 per MW made by participants in the short-term energy markets operated by the CalISO and the CalPX from May 1, 2000 to October 2, 2000. In May 2004, the FERC provided notice that Avista Energy was no longer subject to this investigation. In March and April 2005, the California Parties and PG&E, respectively, petitioned for review of the FERC's decision by the United States Court of Appeals for the Ninth Circuit. In addition, many of the other orders that the FERC has issued in the California refund proceedings are now on appeal before the Ninth Circuit. Some of those issues have been consolidated as a result of a case management conference conducted in September 2004. In October 2004, the Ninth Circuit ordered that briefing proceed in two rounds. The first round is limited to three issues: (1) which parties are subject to the FERC's refund jurisdiction in light of the exemption for government-owned utilities in section 201(f) of the Federal Power Act (FPA); (2) the temporal scope of refunds under section 206 of the FPA; and (3) which categories of transactions are subject to refunds. In September 2005, the Ninth Circuit held that the FERC did not have the authority to order refunds for sales made by municipal utilities in the California Refund Case. In August 2006, the Ninth Circuit upheld October 2, 2000 as the refund effective date for the FPA section 206 Refund Proceeding, but remanded to the FERC its decision not to consider a FPA section 309 remedy for tariff violations prior to October 2, 2000. The Ninth Circuit also granted California's petition for review challenging the FERC's exclusion of the energy exchange transactions as well as the FERC's exclusion of forward market transactions from the California refund proceedings. The Ninth Circuit has extended until June 13, 2007, the time for filing petitions for rehearing. It is unclear at this time what impact, if any, the Court's remand might have on Avista Energy. The second round of issues and their corresponding briefing schedules have not yet been set by the Ninth Circuit Court of Appeals.

Because the resolution of the California refund proceeding remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect that the California refund proceeding will have a material adverse effect on its financial condition, results of operations or cash flows. This is primarily due to the fact that FERC orders have stated that any refunds will be netted against unpaid amounts owed to the respective parties and the Company does not believe that refunds would exceed unpaid amounts owed to the Company.

AVISTA CORPORATION

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. During the hearing, Avista Utilities and Avista Energy vigorously opposed claims that rates for spot market sales were unjust and unreasonable and that the imposition of refunds would be appropriate. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. Seven petitions for review, including one filed by Puget Sound Energy, Inc. (Puget), are now pending before the United States Court of Appeals for the Ninth Circuit. Opening briefs were filed in January 2005. Petitioners other than Puget challenged the merits of the FERC's decision not to order refunds. Puget's brief is directed to the procedural flaws in the underlying docket. Puget argues that because its complaint was withdrawn as a matter of law in July 2001, the FERC erred in relying on it to serve as the basis to initiate the preliminary investigation into whether refunds for individually negotiated bilateral transactions in the Pacific Northwest were appropriate. In February 2005, intervening parties, including Avista Energy and Avista Utilities, filed in support of Puget and also filed in opposition to the other six petitioners. Briefing was completed in May 2005 and oral arguments were heard on January 8, 2007. Because the resolution of the Pacific Northwest refund proceeding remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect that the Pacific Northwest refund proceeding will have a material adverse effect on its financial condition, results of operations or cash flows.

California Attorney General Complaint

In May 2002, the FERC conditionally dismissed a complaint filed in March 2002 by the Attorney General of the State of California (California AG) that alleged violations of the Federal Power Act by the FERC and all sellers (including Avista Corp. and its subsidiaries) of electric power and energy into California. The complaint alleged that the FERC's adoption and implementation of market-based rate authority was flawed and, as a result, individual sellers should refund the difference between the rate charged and a just and reasonable rate. In May 2002, the FERC issued an order dismissing the complaint but directing sellers to re-file certain transaction summaries. It was not clear that Avista Corp. and its subsidiaries were subject to this directive but the Company took the conservative approach and re-filed certain transaction summaries in June and July of 2002. In July 2002, the California AG requested a rehearing on the FERC order, which request was denied in September 2002. Subsequently, the California AG filed a Petition for Review of the FERC's decision with the United States Court of Appeals for the Ninth Circuit. In September 2004, the United States Court of Appeals for the Ninth Circuit upheld the FERC's market-based rate authority, but found the requirement that all sales at market-based rates be contained in quarterly reports filed with the FERC to be integral to a market-based rate tariff. The California AG has interpreted the decision as providing authority to the FERC to order refunds in the California refund proceeding for an expanded refund period. The Court's decision leaves to the FERC the determination as to whether refunds are appropriate. In October 2004, Avista Energy joined with others in seeking rehearing of the Court's decision to remand the case back to the FERC for further proceedings. The Court denied the request without explanation on July 31, 2006. The Ninth Circuit has stayed the mandate in this case until June 13, 2007. On December 28, 2006 certain parties filed a petition for a writ of certiorari at the Supreme Court, which is currently pending. The California AG responded to that petition on February 5, 2007 and filed its own conditional cross-petition for a writ of certiorari. The FERC opposed the petition for a writ of certiorari and the cross-petition in April 2007. Based on information currently known to the Company's management, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

Wah Chang Complaint

In May 2004, Wah Chang, a division of TDY Industries, Inc. (a subsidiary of Allegheny Technologies, Inc.), filed a complaint in the United States District Court for the District of Oregon against numerous companies, including Avista Corp., Avista Energy and Avista Power. This complaint is similar to the Port of Seattle complaint (which was dismissed by the United States District Court and the United States Court of Appeals for the Ninth Circuit as disclosed in the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006) and seeks compensatory and treble damages for alleged violations of the Sherman Act, the Racketeer Influenced and Corrupt Organization Act, as well as violations of Oregon state law. According to the complaint, from September 1997 to September 2002, the plaintiff purchased electricity from PacifiCorp pursuant to a contract that was indexed to the spot wholesale market price of electricity. The plaintiff alleges that the defendants, acting in concert among themselves and/or with Enron Corporation and certain affiliates thereof (collectively, Enron) and others, engaged in a scheme to defraud electricity customers by transmitting false market information in interstate commerce in order to artificially increase the price of electricity provided by them, to receive payment for services not provided by them and to otherwise manipulate the market price of electricity, and by executing wash trades and other forms of market manipulation techniques and sham transactions. The plaintiff also alleges that the defendants, acting in concert among themselves and/or with Enron and others, engaged in numerous practices involving the generation, purchase, sale, exchange, scheduling and/or transmission of electricity with the purpose and effect of causing a shortage (or the appearance of a shortage) in the generation of electricity and congestion (or the appearance of congestion) in the transmission of electricity, with the ultimate purpose and effect of artificially and illegally fixing and raising the price of electricity in California and throughout the Pacific Northwest. As a result of the defendants' alleged conduct, the plaintiff allegedly suffered damages of not less than $30 million through the payment of higher electricity prices. In September 2004, this case was transferred to the United States District Court for the Southern District of California for consolidation with other pending actions. In February 2005, the Court granted the defendants' motion to dismiss the complaint because it determined that it was without jurisdiction to hear the plaintiff's complaint, based on, among other things, the exclusive jurisdiction of the FERC and the filed-rate doctrine. In March 2005, Wah Chang filed an appeal with the United States Court of Appeals for the Ninth Circuit. The appeal of Wah Chang is still pending before the Ninth Circuit and oral arguments were heard on April 10, 2007. Because the resolution of this lawsuit remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect that this lawsuit will have a material adverse effect on its financial condition, results of operations or cash flows.

City of Tacoma Complaint

In June 2004, the City of Tacoma, Department of Public Utilities, Light Division, a Washington municipal corporation (Tacoma Power), filed a complaint in the United States District Court for the Western District of Washington against over fifty companies, including Avista Corp., Avista Energy and Avista Power. According to the complaint, Tacoma Power distributes electricity to customers in Tacoma, and Pierce County, Washington, generates electricity at several facilities in western Washington and purchases power under supply contracts and in the Northwest spot market. Tacoma Power's complaint was similar to the Port of Seattle complaint (which was dismissed by the United States District Court and the United States Court of Appeals for the Ninth Circuit as disclosed in the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006) and seeks compensatory and treble damages from alleged violations of the Sherman Act. Tacoma Power alleged that the defendants, acting in concert, engaged in a pattern of activities that had the purpose and effect of creating the impressions that the demand for power was higher, the supply of power was lower, or both, than was in fact the case. This allegedly resulted in an artificial increase of the prices paid for power sold in California and elsewhere in the western United States during the period from May 2000 through the end of 2001. Due to the alleged unlawful conduct of the defendants, Tacoma Power allegedly paid an amount estimated to be $175.0 million in excess of what it would have paid in the absence of such alleged conduct. In September 2004, this case was transferred to the United States District Court for the Southern District of California for consolidation with other pending actions. In February 2005, the Court granted the defendants' motion to dismiss this complaint for similar reasons to those expressed by the Court in the Wah Chang complaint described above. In March 2005, Tacoma Power filed an appeal with the United States Court of Appeals for the Ninth Circuit. In March 2007, the Ninth Circuit approved a Stipulation of Dismissal of the appeal, thus ending Tacoma Power's complaint.

State of Montana Proceedings

In June 2003, the Attorney General of the State of Montana (Montana AG) filed a complaint in the Montana District Court on behalf of the people of Montana and the Flathead Electric Cooperative, Inc. against numerous companies, including Avista Corp. The complaint alleges that the companies illegally manipulated western electric and natural gas markets in 2000 and 2001. This case was subsequently moved to the United States District Court for the District of Montana; however, it has since been remanded back to the Montana District Court.

The Montana AG also petitioned the Montana Public Service Commission (MPSC) to fine public utilities $1,000 a day for each day it finds they engaged in alleged "deceptive, fraudulent, anticompetitive or abusive practices" and order refunds when consumers were forced to pay more than just and reasonable rates. In February 2004, the MPSC issued an order initiating investigation of the Montana retail electricity market for the purpose of determining whether there is evidence of unlawful manipulation of that market. The Montana AG has requested specific information from Avista Energy and Avista Corp. regarding their transactions within the state of Montana during the period from January 1, 2000 through December 31, 2001.

Because the resolution of these proceedings remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect that these proceedings will have a material adverse effect on its financial condition, results of operations or cash flows.

Montana Public School Trust Fund Lawsuit

In October 2003, a lawsuit was originally filed by two residents of the state of Montana in the United States District Court for the District of Montana against all private owners of hydroelectric dams in Montana, including Avista Corp. The lawsuit alleged that the hydroelectric facilities are located on state-owned riverbeds and the owners of the dams have never paid compensation to the state's public school trust fund. The lawsuit requests lease payments dating back to the construction of the respective dams and also requests damages for trespassing and unjust enrichment. In February 2004, the Company filed its motion to dismiss this lawsuit; PacifiCorp and PPL Montana, the other named defendants, also filed a motion to dismiss, or joined therein. In May 2004, the Montana AG filed a complaint on behalf of the state in the District Court to join in this lawsuit to allegedly protect and preserve state lands/school trust lands from use without compensation. In July 2004, the defendants (including Avista Corp.) filed a motion to dismiss the Montana AG's complaint. In September 2004, the motion to dismiss the Montana AG's complaint was denied, rejecting the defendants' argument, among other things, that the FERC has exclusive jurisdiction over this matter. In September 2005, the U.S. District Court issued an order vacating its prior decision based on lack of jurisdiction.

In November 2004, the defendants (including Avista Corp.) filed a petition for declaratory relief in Montana State Court requesting the resolution of the claim that the plaintiffs raised in federal court, as discussed above, and the Montana AG filed an answer, counterclaim and motion for summary judgment. In June 2005, Avista Corp. moved for leave to amend its complaint to, inter alia, add two causes of action relating to breach of contract and negligent misrepresentation arising out of its Clark Fork Settlement Agreement that was entered into in 1999 with the state of Montana relating to the relicensing of Avista Corp.'s Noxon Rapids Hydroelectric Generating Project. On April 14, 2006, the Montana State Court granted the Montana AG's motion for summary judgment and denied Avista Corp.'s motion to amend its complaint to add its breach of contract and negligent misrepresentation claims. However, the Montana State Court granted Avista Corp.'s motion to amend its complaint to contend that the Clark Fork River is not navigable. The Company contends that if the Clark Fork River was not navigable at the time of statehood in 1889, the state of Montana never acquired ownership of the riverbeds under the equal footing doctrine. The Court determined that the Montana AG's claims for compensation were not preempted by the Federal Power Act because the claims were not, on their face, in conflict with Montana law, nor were they preempted by a federal navigational right for purposes of interstate commerce. The Court also rejected defenses based on estoppel, waiver, and the statute of limitations. The Court did not relieve the Montana AG, however, of its obligation to prove that the state of Montana actually owns the riverbeds or that the land is part of a school trust under the Montana Constitution. In addition, the question of whether there is federal preemption under the Federal Power Act, not on its face, but as actually applied in these circumstances, and the question of compensation, still remain open issues in the case. On May 16, 2006, the state of Montana filed a motion for summary judgment on the question of liability. On October 6, 2006, the Company filed several motions, which addressed, among other things, the question of navigability of the Clark Fork River arguing that since the Clark Fork River was not navigable at the time of statehood, the state of Montana never acquired ownership of the riverbeds under the equal footing doctrine. Oral arguments on the Company's motions were heard in December 2006. The Company expects this matter to proceed in the normal course of litigation and a trial date is currently scheduled for October 2007. Because the resolution of this lawsuit remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, the Company intends to seek recovery, through the rate making process, of any amounts paid.

Colstrip Generating Project Complaints

In May 2003, various parties (all of which are residents or businesses of Colstrip, Montana) filed a consolidated complaint against the owners of the Colstrip Generating Project (Colstrip) in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs allege damages to buildings as a result of rising ground water, as well as damages from contaminated waters leaking from the lakes and ponds of Colstrip. The plaintiffs are seeking punitive damages, an order by the court to remove the lakes and ponds and the forfeiture of all profits earned from the generation of Colstrip. The owners of Colstrip have undertaken certain groundwater investigation and remediation measures to address groundwater contamination. These measures include improvements to the lakes and ponds of Colstrip. The Company intends to continue to work with the other owners of Colstrip in defense of this complaint. Because the resolution of this lawsuit remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect that this lawsuit will have a material adverse effect on its financial condition, results of operations or cash flows.

In March 2007, a group of ranchers filed a consolidated complaint against the owners of Colstrip in Montana District Court. The plaintiffs allege damages to livestock, land and water from contaminated waters leaking from the waste water pond of Colstrip. The plaintiffs are seeking unspecified punitive damages. The Company intends to work with the other owners of Colstrip to defend this complaint. There is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred.

Environmental Protection Agency Administrative Compliance Order

In December 2003, PPL Montana, LLC, as operator of Colstrip, received an Administrative Compliance Order (ACO) from the Environmental Protection Agency (EPA) pursuant to the Clean Air Act (CAA). The ACO alleged that Colstrip Units 3 & 4 have been in violation of the CAA permit at Colstrip since the units came on-line in the 1980s. The permit required the Colstrip project operator to submit for review and approval by the EPA, an analysis and proposal for reducing emissions of nitrogen oxides to address visibility concerns if, and when, EPA promulgates Best Available Retrofit Technology requirements for nitrogen oxide emissions. The EPA asserted that regulations it promulgated in 1980 triggered this requirement. In March 2007, the owners of Colstrip finalized a settlement agreement with the EPA, the Department of Environmental Quality (Montana DEQ) and the Northern Cheyenne Tribe. The settlement agreement resolves the potential liability related to this issue and will result in the installation of additional nitrogen oxide emissions control equipment at Colstrip. The Company’s share of the total costs related to the settlement agreement is not material to the Company’s financial condition or results of operations.

Colstrip Royalty Claim

Western Energy Company (WECO) supplies coal to the owners of Colstrip Units 3 & 4 under a Coal Supply Agreement and a Transportation Agreement. Avista Corp. owns a 15 percent interest in Colstrip Units 3 & 4. The Minerals Management Service (MMS) of the United States Department of the Interior issued an order to WECO to pay additional royalties concerning coal delivered to Colstrip Units 3 & 4 via the conveyor belt (4.46 miles long). The owners of Colstrip Units 3 & 4 take delivery of the coal at the beginning of the conveyor belt. The order asserts that additional royalties are owed MMS as a result of WECO not paying royalties in connection with revenue received by WECO from the owners of Colstrip Units 3 & 4 under the Transportation Agreement during the period October 1, 1991 through December 31, 2001. WECO’s appeal to the MMS was substantially denied in March 2005; WECO has now appealed the order to the Board of Land Appeals of the U.S. Department of the Interior. The entire appeal process could take several years to resolve. The owners of Colstrip Units 3 & 4 are monitoring the appeal process between WECO and MMS. WECO has indicated to the owners of Colstrip Units 3 & 4 that if WECO is unsuccessful in the appeal process, WECO will seek reimbursement of any royalty payments by passing these costs through the Coal Supply Agreement. The owners of Colstrip Units 3 & 4 advised WECO that their position would be that these claims are not allowable costs per the Coal Supply Agreement nor the Transportation Agreement in the event the owners of Colstrip Units 3 & 4 were invoiced for these claims. Presumably, royalty and tax demands for periods of time after the years in dispute and future years will be determined by the outcome of the pending proceedings. Because the resolution of this issue remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company’s liability. Based on information currently known to the Company’s management, the Company does not expect that this issue will have a material adverse effect on its financial condition, results of operations or cash flows. However, the Company would most likely seek recovery, through the rate making process, of any amounts paid.

Spokane River

The Company has entered into a settlement with the state of Washington’s Department of Ecology (DOE) and Kaiser Aluminum & Chemical Corporation (Kaiser) relating to the remediation of a contaminated site on the Spokane River. The Company’s involvement with this contaminated site relates to its previous ownership of a wastewater treatment plant through Avista Development. Under the agreement with the DOE and Kaiser, the Company is performing the selected remedial action under the Cleanup Action Plan. Kaiser, operating under Chapter 11 bankruptcy protection, paid the Company approximately 50 percent of the estimated total costs, which was approved by the Kaiser bankruptcy judge. The funds from Kaiser have been used by the Company to pay a portion of the costs of the remediation. The Company accrued its share of the total estimated costs, which was not material to the Company’s financial condition or results of operations. Under the direction of the Company, work under the Cleanup Action Plan was substantially completed by January 2007. Final work should be completed in the second quarter of 2007. Because of uncertainties with respect to, among other things, unforeseen site conditions, the Company’s estimate of its liability could change in future periods. Based on information currently known to the Company’s management, the Company does not believe that such a change would be material to its financial condition, results of operations or cash flows.

Northeast Combustion Turbine Site

In August 2005, a diesel fuel spill occurred at the Company's Northeast Combustion Turbine generating facility (Northeast CT) located in Spokane, Washington. The Northeast CT site had fuel storage facilities that were leased to Co-op Supply, Inc., an affiliate of Cenex Cooperative (Co-op). The fuel spill occurred when Co-op made a delivery of diesel to a tank that was already nearly full, causing excess fuel to overflow into a containment area. It is estimated that approximately 26,000 gallons of fuel escaped the containment area and leaked into the soil below it. An investigation, supervised by the DOE, determined the fuel was, for the most part, uniformly present in the soil to a depth of 30-35 feet. Groundwater below the site is at a depth of 170 feet. The Company immediately commenced remediation efforts, including the removal of contaminated soil and the related fuel storage facilities. The Company accrued the estimated cleanup costs during 2005, which was not material to the Company's consolidated financial condition or results of operations. During the fourth quarter of 2005, the Company filed a complaint against Co-op and an engineering firm to recover a substantial portion of the cleanup costs. Through mediation the Company recovered a substantial portion of the cleanup costs from Co-op and the engineering firm in the fourth quarter of 2006. The Company's estimate of its liability could change in future periods. Based on information currently known to the Company's management, the Company does not believe that such a change would be material to its financial condition, results of operations or cash flows.

Harbor Oil Inc. Site

Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, EPA Region 10 provided notification to Avista Corp., as a customer of Harbor Oil, that the EPA had determined that hazardous substances were released at the Harbor Oil site in Portland, Oregon and that Avista Corp. may be liable for investigation and cleanup of the site under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as the federal "Superfund" law. Harbor Oil's primary business was the collection and blending of used oil for sale as fuel to ships at sea. The initial indication from the EPA is that the site may be contaminated with PCBs, petroleum hydrocarbons, chlorinated solvents and heavy metals. Thirteen other companies received a similar notice, including current and former owners of the site, the Bonneville Power Administration, Portland General Electric Company, Northwestern Energy and Unocal Oil. Several meetings have been held with the EPA and certain of the Potentially Responsible Parties (PRPs) to ask questions of the EPA regarding the Harbor Oil site, as well as drafting an administrative compliance order related to conducting a remedial investigation and feasibility study for the site. The Company intends to fund a share of a remedial investigation and feasibility study of the site, which is not expected to be material to its financial condition or results of operations. Based on the review of its records related to Harbor Oil, the Company does not believe it is a major contributor to this potential environmental contamination based on the relative volume of waste oil delivered to the Harbor Oil site. However, there is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred. As such, it is not possible to make an estimate of any liability at this time.

Lake Coeur d'Alene

In July 1998, the United States District Court for the District of Idaho issued its finding that the Coeur d'Alene Tribe of Idaho (Tribe) owns, among other things, portions of the bed and banks of Lake Coeur d'Alene (Lake) lying within the current boundaries of the Coeur d'Alene Reservation. This action had been brought by the United States on behalf of the Tribe against the state of Idaho. The Company was not a party to this action. The United States District Court decision was affirmed by the United States Court of Appeals for the Ninth Circuit. The United States Supreme Court affirmed this decision in June 2001. This ownership decision will result in, among other things, the Company being liable to the Tribe for compensation for the use of reservation lands under Section 10(e) of the Federal Power Act.

The Company's Post Falls Hydroelectric Generating Station (Post Falls), a facility constructed in 1906 with annual generation of 10 aMW, utilizes a dam on the Spokane River downstream of the Lake which controls the water level in the Lake for portions of the year (including portions of the lakebed owned by the Tribe). The Company has other hydroelectric facilities on the Spokane River downstream of Post Falls, but these facilities do not affect the water level in the Lake. The Company and the Tribe are engaged in discussions related to past and future compensation (which may include interest) for use of the portions of the bed and banks of the Lake, which are owned by the Tribe. If the parties cannot agree on the amount of compensation, the matter could result in litigation. The Company cannot predict the amount of compensation that it will ultimately pay or the terms of such payment. The Company intends to seek recovery, through the rate making process, of any amounts paid.

Spokane River Relicensing

The Company owns and operates six hydroelectric plants on the Spokane River, and five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls, which have a total present capability of 155.7 MW) are under one FERC license and are referred to as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. The license for the Spokane River Project expires on August 1, 2007; the Company filed a Notice of Intent to Relicense in July 2002. The formal consultation process involving planning and information gathering with stakeholder groups has been underway since that time. The Company filed its new license applications with the FERC in July 2005. The Company has requested the FERC to consider a license for Post Falls, which has a present capability of 18 MW, that is separate from the other four hydroelectric plants because Post Falls presents more complex issues that may take longer to resolve than those dealing with the rest of the Spokane River Project. If granted, new licenses would have a term of 30 to 50 years. In the license applications, the Company proposed a number of measures intended to address the impact of the Spokane River Project and enhance resources associated with the Spokane River.

Since the Company's July 2005 filing of applications to relicense the Spokane River Project, the FERC has continued various stages of processing the applications. In May 2006, the FERC issued a notice calling for terms and conditions regarding the two license applications. In response to that notice, a number of parties (including the Coeur d'Alene Tribe, the state of Idaho, Washington State agencies, and the United States Department of Interior (DOI)) filed either recommended terms and conditions, pursuant to Sections 10(a) and 10(j) of the Federal Power Act (FPA), or mandatory conditions related to the Post Falls application, pursuant to Section 4(e) of the FPA. The Company's initial estimate of the potential cost of the conditions proposed for Post Falls total between $400 million and $500 million over a 50-year period. This assumes all conditions, both mandatory and recommended, as well as the Company's proposed conditions, would be included in a final license issued by the FERC, which the Company believes to be unlikely. For the rest of the Spokane River Project, which is located in Washington, the Company's initial estimate of the cost of meeting the recommended conditions, should they be included in a final license, totals between $175 million and $225 million over a 50-year period. These cost estimates are based on the preliminary conditions and recommendations and will be updated based on the outcome of the FERC proceedings.

The Company requested a trial-type hearing on facts in front of an Administrative Law Judge (ALJ) related to the DOI's mandatory conditions for Post Falls. In January 2007, the ALJ issued his ruling regarding the Company's challenge of the facts. The Company believes that the ALJ's factual findings support, in several key areas, its analysis of the facts at hand. The ALJ's factual findings also support the DOI's analysis in certain areas as well.

The Bureau of Indian Affairs, which is part of the DOI and is charged with protecting project-related resources on the Coeur d'Alene Indian Reservation and has authority to set conditions for the Company's license, is now expected to use the ALJ's findings to formulate final mandatory conditions for the operation of Post Falls. The DOI is expected to issue final mandatory conditions by May 7, 2007.

The broader relicensing process continues under the jurisdiction of the FERC. The FERC issued a draft environmental impact statement (DEIS) in December 2006 that was open for public review and comment through March 6, 2007. The DEIS includes the FERC's initial analysis of the applications, along with analysis of proposed recommended and mandatory terms and conditions. Many parties, including resource agencies and Tribes, commented to the FERC regarding the DEIS, as did Avista Corp. The Company also filed reply comments regarding the comments that the FERC received from other parties. The FERC will prepare a Final Environmental Impact Statement (FEIS) after review and consideration of comments. The Company cannot predict the schedule for the issuance of the FEIS. While the FERC's draft analysis leads the Company to believe the ultimate cost of relicensing may be less than its earlier projections as disclosed above, the Company is unable to base specific new cost estimates on this analysis.

The relicensing process also triggers review under the Endangered Species Act. In the DEIS, the FERC analyzed potential project impacts on listed and threatened endangered species, and has determined that the proposed action and continued operation of the Post Falls and Spokane River projects, is not likely to adversely affect any threatened or endangered species. The Company prepared a draft Biological Assessment in 2005. The FERC has issued a Biological Assessment and formally requested concurrence from the United States Department of Fish and Wildlife Service (USFWS). The USFWS responded by letter, concurring with regards to bald eagles, and requesting additional information regarding bull trout. The Company has filed a supplemental report to address the USFWS information request. If the FERC initiates formal consultation with the USFWS, additional evaluation will be required by the Company.

In addition, the Company must receive Clean Water Act Certifications from the states of Idaho and Washington for the Projects. Applications for such certification were filed last July with each state; the FERC is precluded from issuing a license order until such certification has been issued, or waived, by the states. The Company cannot predict the schedule for these final phases of relicensing.

If the FERC is unable to issue new license orders prior to the August 1, 2007 expiration of the current license, an annual license will be issued, in effect extending the current license and its conditions. The Company has no reason to believe that Spokane River Project operations would be interrupted in any manner relative to the timing of the FERC's actions.

The total annual operating and capitalized costs associated with the relicensing of the Spokane River Project will become better known and estimable as the process continues. The Company intends to seek recovery, through the rate making process, of all such operating and capitalized costs.

Clark Fork Settlement Agreement

Dissolved atmospheric gas levels exceed state of Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement, the Company developed an abatement and mitigation strategy with the other signatories to the agreement and completed the Gas Supersaturation Control Program (GSCP). The Idaho Department of Environmental Quality and the USFWS approved the GSCP in February 2004 and the FERC issued an order approving the GSCP in January 2005.

The GSCP provides for the opening and modification of one and, potentially, both of the two existing diversion tunnels built when Cabinet Gorge was originally constructed. When river flows exceed the capacity of the powerhouse turbines, the excess flows would be diverted to the tunnels rather than released over the spillway. The Company has undertaken physical and computer modeling studies to confirm the feasibility and likely effectiveness of its tunnel solution. The Company has completed its preliminary design development efforts (which include additional computer model studies, some site investigation, and preliminary engineering design) and the cost estimates have been updated. Analysis of the predicted total dissolved gas (TDG) performance indicates that the tunnels are unlikely to meet the performance criteria anticipated in the GSCP. The costs of modifying the first tunnel are now estimated to be $58 million (using 2006 dollars with inflation projected at 5 percent) with the majority of these costs to be incurred in 2008 through 2012, an increase from prior estimates of $38 million and an extension of the schedule. The calculated updated cost estimates to modify the second tunnel are $39 million, an increase from prior estimates of $26 million. The second tunnel would be modified only after evaluation of the performance of the first tunnel and such modifications would commence no later than ten years following the completion of the first tunnel. The increases in costs are mainly due to inflation and large increases in materials costs, such as concrete and steel. Efforts will continue throughout 2007 toward the completion of a final Design Development Report, which will include updated tunnel performance predictions, cost estimates, and schedule. As a result of the predicted TDG performance, the new cost estimates and extension of the schedule, the Company will continue meeting with stakeholders to explore amending the GSCP and possible alternatives to the construction of the tunnels. The Company intends to seek recovery, through the rate making process, of the costs to address the dissolved atmospheric gas levels, including the mitigation payments.

The USFWS has listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company is evaluating the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies will help the Company and other parties determine the best use of funds toward continuing fish passage efforts or other bull trout population enhancement measures.

Air Quality

The Company must be in compliance with requirements under the Clean Air Act and Clean Air Act Amendments for its thermal generating plants. The Company continues to monitor legislative developments at both the state and national level for the potential of further restrictions on sulfur dioxide, nitrogen oxide, carbon dioxide (including cap and trade emission reduction programs), as well as other greenhouse gas and mercury emissions.

In particular, the EPA has finalized mercury emission regulations that will affect coal-fired generation plants, including Colstrip. The new EPA regulations establish an emission trading program to take effect beginning in January 2010, with a second phase to take effect in 2018. In addition, in 2006, the Montana DEQ adopted final rules for the control of mercury emissions from coal-fired plants that are more restrictive than EPA regulations. The new rules set strict mercury emission limits by 2010, and put in place a recurring ten-year review process to ensure facilities are keeping pace with advancing technology in mercury emission control. The rules also provide for temporary alternate emission limits provided certain provisions are met, and they allocate mercury emission credits in a manner that rewards the cleanest facilities. Avista Corp. owns a 15 percent interest in Colstrip Units 3 & 4, located in Montana.

Compliance with these new and proposed requirements and possible additional legislation or regulations will result in increases to capital expenditures and operating expenses for expanded emission controls at the Company's thermal generating facilities. The Company, along with the other owners of Colstrip, are in the process of computing estimates for the amount of these costs and the impact the restrictions will have on the operation of the facilities. The Company will continue to seek recovery, through the rate making process, of the costs to comply with various air quality requirements.

Residential Exchange Program

The Residential Exchange Program provides access to the benefits of low-cost federal hydroelectricity to residential and small-farm customers of the region's investor-owned utilities. The Bonneville Power Administration (BPA) administers the Residential Exchange Program. Avista Corp. has executed an agreement with the BPA in settlement of each party's rights and obligations related to the Residential Exchange Program for the period October 1, 2001 through September 30, 2011. The benefits that Avista Corp. receives under the agreement with the BPA are passed through directly to its residential and small-farm customers via a credit to their monthly electric bills. The current BPA rate period covers the second five years of the ten-year agreement, which began on October 1, 2006 and continues through September 30, 2011. Numerous parties filed Petitions for Review in the Ninth Circuit Court of Appeals challenging the agreements between Avista Corp. and the BPA, as well as the BPA's agreements with other investor-owned utilities. On May 3, 2007, the Ninth Circuit Court of Appeals ruled that the settlement agreements entered into between the BPA and investor-owned utilities (including Avista Corp.) are inconsistent with the Northwest Power Act. The Company and the BPA are evaluating the impact this ruling will have on the Residential Exchange Program. Since these benefits are passed through to Avista Corp.'s customers as adjustments to electric rates, which must be approved by the WUTC and the IPUC, the ruling by the Ninth Circuit Court of Appeals is not expected to have a significant effect on the Company's financial condition or results of operations. However, there is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material adverse impact on its financial condition, results of operations or cash flows. It is possible that a change could occur in the Company's estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant.

NOTE 13. POTENTIAL HOLDING COMPANY FORMATION

At the 2006 Annual Meeting of Shareholders in May 2006, the shareholders of Avista Corp. approved a proposal to proceed with a statutory share exchange, which would change the Company's organization to a holding company structure. The holding company, currently named AVA Formation Corp. (AVA), would become the parent of Avista Corp. After the contemplated dividend to AVA of the capital stock of Avista Capital (Avista Capital Dividend) now held by Avista Corp., AVA would then also be the parent of Avista Capital. The Avista Capital Dividend would effect the structural separation of Avista Corp.'s non-utility businesses from its regulated utility business. Since the company's 9.75 percent Senior Notes due June 1, 2008 contain a restriction that would prohibit the Avista Capital Dividend (but not the holding company structure), the dividend would not be distributed until the Senior Notes are retired.

Avista Corp. received approval from the FERC in April 2006 (conditioned on approval by the state regulatory agencies), the IPUC in June 2006 and the WUTC in February 2007. Avista Corp. has also filed for approval from the utility regulators in Oregon and Montana. The statutory share exchange is subject to the receipt of the remaining regulatory approvals and the satisfaction of other conditions. If the statutory share exchange and the implementation of the holding company structure are approved by regulators on terms acceptable to the Company, it may be completed sometime after mid-2007.

The IPUC accepted a stipulation entered into between Avista Corp. and the IPUC Staff that sets forth a variety of conditions, which would serve to segregate the Company's utility operations from the other businesses conducted by the holding company. The stipulation would require Avista Corp. to maintain certain common equity levels as part of its capital structure. Avista Corp. has committed to increase its actual utility common equity component to 35 percent by the end of 2007 and 38 percent by the end of 2008, which is consistent with provisions of the Company's Washington general rate case implemented on January 1, 2006. The calculation of the utility equity component is essentially the ratio of Avista Corp.'s total common equity to total capitalization excluding, in each case, Avista Corp.'s investment in Avista Capital. In addition, IPUC approval would be required for any dividend from Avista Corp. to the holding company that would reduce utility common equity below 25 percent of total capitalization which, for this purpose, includes long and short-term debt, capitalized lease obligations and preferred and common equity.

The WUTC accepted a similar stipulation entered into between Avista Corp. and the WUTC staff. The stipulation requires Avista Corp. to increase its actual utility common equity component to 40 percent by June 30, 2008. In addition, WUTC approval would be required for any dividend from Avista Corp. to the holding company that would reduce utility common equity below 30 percent of total capitalization.

Pursuant to the Plan of Share Exchange, a statutory share exchange would be effected whereby each outstanding share of Avista Corp. common stock would be exchanged for one share of AVA common stock, no par value, so that holders of Avista Corp. common stock would become holders of AVA common stock and Avista Corp. would become a subsidiary of AVA. The other outstanding securities of Avista Corp. would not be affected by the statutory share exchange, with limited exceptions for stock options and other securities outstanding under equity compensation and employee benefit plans.

AVISTA CORPORATION

NOTE 14. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis currently used by the Company's management to analyze performance and determine the allocation of resources. Avista Utilities' business is managed based on the total regulated utility operation. The Energy Marketing and Resource Management business segment primarily consists of electricity and natural gas marketing, trading and resource management, including optimization of energy assets owned by other entities and derivative commodity instruments such as futures, options, swaps and other contractual arrangements. On April 16, 2007, Avista Energy and Avista Energy Canada entered into a purchase and sale agreement to sell substantially all of their contracts and ongoing operations. Completion of this transaction will effectively end the majority of the operations of the Energy Marketing and Resource Management business segment. See Note 3 for further information. Advantage IQ is a provider of facility information and cost management services for multi-site customers throughout North America. The Other business segment includes other investments and operations of various subsidiaries as well as certain other operations of Avista Capital.

The following table presents information for each of the Company's business segments (dollars in thousands):

	Avista Utilities	Energy Marketing And Resource Management	Advantage IQ	Other	Intersegment Eliminations (1)	Total
For the three months ended March 31, 2007:						
Operating revenues	$ 414,266	$ 29,409	$ 10,999	$ 4,513	$ —	$ 459,187
Resource costs	269,986	37,727	—	—	—	307,713
Gross margin	144,280	(8,318)	—	—	—	135,962
Other operating expenses	49,041	5,085	7,827	4,224	—	66,177
Depreciation and amortization	21,090	178	596	501	—	22,365
Income (loss) from operations	50,154	(13,581)	2,576	(212)	—	38,937
Interest expense (2)	22,021	83	81	144	(146)	22,183
Income taxes	10,997	(4,332)	912	(90)	—	7,487
Net income (loss)	19,927	(7,623)	1,584	206	—	14,094
Capital expenditures	40,555	206	758	375	—	41,894
For the three months ended March 31, 2006:						
Operating revenues	$ 423,290	$ 61,542	$ 9,076	$ 5,294	$ —	$ 499,202
Resource costs	271,605	50,127	—	—	—	321,732
Gross margin	151,685	11,415	—	—	—	163,100
Other operating expenses	45,727	4,753	6,163	5,395	—	62,038
Depreciation and amortization	20,980	342	515	591	—	22,428
Income (loss) from operations	62,912	6,320	2,398	(692)	—	70,938
Interest expense (2)	23,680	46	196	568	(641)	23,849
Income taxes	15,811	2,709	775	(778)	—	18,517
Net income (loss)	26,172	5,046	1,427	(1,073)	—	31,572
Capital expenditures	29,743	271	365	1	—	30,380
Total Assets:						
Total assets as of March 31, 2007	$ 2,821,337	$ 936,987	$ 102,259	$ 44,046	$ —	$ 3,904,629
Total assets as of December 31, 2006	2,895,883	1,017,203	100,431	42,991	—	4,056,508

(1) Intersegment eliminations reported as interest expense represent intercompany interest.

(2) Including interest expense to affiliated trusts.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Avista Corporation
Spokane, Washington

We have reviewed the accompanying consolidated balance sheet of Avista Corporation and subsidiaries (the "Corporation") as of March 31, 2007, and the related consolidated statements of income, comprehensive income, and cash flows for the three-month periods ended March 31, 2007 and 2006. These interim financial statements are the responsibility of the Corporation's management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to such consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Avista Corporation and subsidiaries as of December 31, 2006, and the related consolidated statements of income, comprehensive income, and cash flows for the year then ended (not presented herein); and in our report dated February 26, 2007, we expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph for certain changes in accounting and presentation resulting from the impact of recently adopted accounting standards. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2006, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP

May 3, 2007

AVISTA CORPORATION

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Forward-Looking Statements

From time to time, we make forward-looking statements such as statements regarding projected or future:

- financial performance,
- capital expenditures,
- dividends,
- capital structure,
- other financial items,
- strategic goals and objectives, and
- plans for operations.

These statements have underlying assumptions (many of which are based, in turn, upon further assumptions). Such statements are made both in our reports filed under the Securities Exchange Act of 1934, as amended (including this Quarterly Report on Form 10-Q), and elsewhere. Forward-looking statements are all statements except those of historical fact including, without limitation, those that are identified by the use of words that include "will," "may," "could," "should," "intends," "plans," "seeks," "anticipates," "estimates," "expects," "forecasts," "projects," "predicts," and similar expressions.

All forward-looking statements (including those made in this Quarterly Report on Form 10-Q) are subject to a variety of risks and uncertainties and other factors. Most of these factors are beyond our control and many of them could have a significant effect on our operations, results of operations, financial condition or cash flows. This could cause actual results to differ materially from those anticipated in our statements. Such risks, uncertainties and other factors include, among others:

- the completion of the sale of Avista Energy's contracts and ongoing operations as contemplated;
- weather conditions, including the effect of precipitation and temperatures on the availability of hydroelectric resources and the effect of temperatures on customer demand;
- changes in wholesale energy prices that can affect, among other things, cash needed to purchase electricity, natural gas for our retail customers and natural gas fuel for electric generation, and the value of surplus energy sold, as well as the market value of derivative assets and liabilities and unrealized gains and losses;
- volatility and illiquidity in wholesale energy markets, including the availability and prices of purchased energy and demand for energy sales;
- the effect of state and federal regulatory decisions affecting our ability to recover costs and/or earn a reasonable return including, but not limited to, the disallowance of costs that we have deferred;
- the outcome of pending regulatory and legal proceedings arising out of the "western energy crisis" of 2000 and 2001, and including possible retroactive price caps and resulting refunds;
- the outcome of legal proceedings and other contingencies concerning us or affecting directly or indirectly our operations;
- the potential effects of any legislation or administrative rulemaking passed into law, including the possible adoption of national, regional, or state restrictions on greenhouse gas emissions and global warming;
- changes in, and compliance with, environmental and endangered species laws, regulations, decisions and policies, including present and potential environmental remediation costs;
- the potential impact of changes to electric transmission ownership, operation and governance, such as the formation of one or more regional transmission organizations or similar entities;
- wholesale and retail competition including, but not limited to, electric retail wheeling and transmission costs;
- the ability to relicense and maintain licenses for our hydroelectric generating facilities at cost-effective levels with reasonable terms and conditions;
- unplanned outages at any of our generating facilities or the inability of facilities to operate as intended;
- unanticipated delays or changes in construction costs, as well as our ability to obtain required operating permits for present or prospective facilities;
- natural disasters that can disrupt energy production or delivery, as well as the availability and costs of materials and supplies and support services;
- blackouts or disruptions of interconnected transmission systems;
- the potential for future terrorist attacks or other malicious acts, particularly with respect to our utility assets;
- changes in the long-term climate of the Pacific Northwest, which can affect, among other things, customer demand patterns and the volume and timing of streamflows to our hydroelectric resources;
- changes in future economic conditions in our service territory and the United States in general, including inflation or deflation and monetary policy;

- changes in industrial, commercial and residential growth and demographic patterns in our service territory;
- the loss of significant customers and/or suppliers;
- failure to deliver on the part of any parties from which we purchase and/or sell capacity or energy;
- changes in the creditworthiness of our customers and energy trading counterparties;
- our ability to obtain financing through the issuance of debt and/or equity securities, which can be affected by various factors including our credit ratings, interest rates and other capital market conditions;
- the effect of any change in our credit ratings;
- changes in actuarial assumptions, the interest rate environment and the actual return on plan assets for our pension plan, which can affect future funding obligations, costs and pension plan liabilities;
- increasing health care costs and the resulting effect on health insurance premiums paid for our employees and retirees;
- increasing costs of insurance, changes in coverage terms and our ability to obtain insurance;
- employee issues, including changes in collective bargaining unit agreements, strikes, work stoppages or the loss of key executives, as well as our ability to recruit and retain employees;
- the potential effects of negative publicity regarding business practices, whether true or not, which could result in, among other things, costly litigation and a decline in our common stock price;
- changes in technologies, possibly making some of the current technology quickly obsolete;
- changes in tax rates and/or policies; and
- changes in our strategic business plans and/or our subsidiaries, which may be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses.

Our expectations, beliefs and projections are expressed in good faith. We believe they have a reasonable basis including, without limitation, an examination of historical operating trends, data contained in our records and other data available from third parties. However, there can be no assurance that our expectations, beliefs or projections will be achieved or accomplished. Furthermore, any forward-looking statement speaks only as of the date on which such statement is made. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for us to predict all of such factors, nor can we assess the effect of each such factor on our business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

The following discussion and analysis is provided for the consolidated financial condition and results of operations of Avista Corp. and its subsidiaries. This discussion focuses on significant factors concerning our financial condition and results of operations and should be read along with the consolidated financial statements.

Potential Holding Company Formation

In May 2006, our shareholders approved a proposal to proceed with a statutory share exchange, which would change our organization to a holding company structure. If the implementation of the holding company structure is approved by regulators on terms acceptable to us, it may be completed sometime after mid-2007. See further information at "Note 13 of the Notes to Consolidated Financial Statements."

Business Segments

We have four business segments as follows:

- **Avista Utilities** – generation, transmission and distribution of electric energy and distribution of natural gas to retail customers, as well as wholesale purchases and sales of energy commodities. Avista Utilities is an operating division of Avista Corp. comprising our regulated utility operations.
- **Energy Marketing and Resource Management** – electricity and natural gas marketing, trading and resource management. The activities of this business segment are conducted primarily by Avista Energy, Inc., an indirect subsidiary of Avista Corp. In April 2007, Avista Energy and Avista Energy Canada entered into a purchase and sale agreement to sell substantially all of their contracts and ongoing operations. Completion of this transaction will effectively end the majority of the operations of this business segment.
- **Advantage IQ** – facility information and cost management services for multi-site customers. The activities of this business segment are conducted by Advantage IQ, Inc., an indirect subsidiary of Avista Corp.
- **Other** – includes sheet metal fabrication, venture fund investments and real estate investments. The activities of this business segment are conducted by various indirect subsidiaries of Avista Corp., including Advanced Manufacturing and Development (AM&D), doing business as METALfx.

Avista Energy, Advantage IQ and the various companies in the Other business segment are subsidiaries of Avista Capital, which is a direct, wholly owned subsidiary of Avista Corp. Our total common stockholders' equity was $927.3 million as of March 31, 2007, of which $242.9 million represented our investment in Avista Capital.

The following table presents net income (loss) for each of our business segments for the three months ended March 31 (dollars in thousands):

	2007	2006
Avista Utilities	$ 19,927	$ 26,172
Energy Marketing and Resource Management	(7,623)	5,046
Advantage IQ	1,584	1,427
Other	206	(1,073)
Net income	$ 14,094	$ 31,572

Executive Level Summary

Overall

Our operating results and cash flows are derived primarily from:

- regulated utility operations (Avista Utilities),
- energy trading, marketing and resource management activities (Avista Energy in the Energy Marketing and Resource Management segment), and
- Advantage IQ.

We intend to continue to focus on improving earnings and operating cash flows, controlling costs and reducing debt while working to restore an investment grade credit rating.

On April 16, 2007, Avista Energy and Avista Energy Canada entered into a purchase and sale agreement to sell substantially all of their contracts and ongoing operations to Coral Energy Holding, L.P. (Coral Energy), as well as certain other subsidiaries of Coral Energy. After closing costs and other adjustments, we do not expect the transaction to result in a significant gain or loss. Proceeds from the transaction will include cash consideration for the net assets acquired by Coral Energy and liquidation of the net current assets of Avista Energy not sold to Coral Energy (primarily receivables, restricted cash and deposits with counterparties). Over time, we plan to redeploy the majority of the estimated $175 million of proceeds from the transaction into our regulated utility operations by reducing debt and investing in capital assets. Until the transaction is completed, Avista Energy's results of operations will continue to be reflected in our consolidated financial statements.

Our net income was $14.1 million for the three months ended March 31, 2007 compared to $31.6 million for the three months ended March 31, 2006. This decrease was primarily due to a net loss in the Energy Marketing and Resource Management segment (Avista Energy) and lower earnings at Avista Utilities.

Avista Utilities

Avista Utilities is our most significant business segment. Our utility operating and financial performance is dependent upon, among other things:

- weather conditions,
- the price of natural gas in the wholesale market, including the effect on the price of fuel for generation,
- the price of electricity in the wholesale market, including the effects of weather conditions, natural gas prices and other factors affecting supply and demand, and
- regulatory decisions, allowing our utility to recover costs, including purchased power and fuel costs, on a timely basis, and to earn a fair return on investment.

Weather has a significant effect on our utility operations. Weather can impact customer demand and operating revenues and we normally have our highest retail (electric and natural gas) energy sales during the winter heating season in the first and fourth quarters of the year. We also have high electricity demand for air conditioning during the summer (third quarter). In general, warmer weather in the heating season and cooler weather in the cooling season will reduce operating revenues. In addition, a reduction in precipitation (particularly winter snowpack) can negatively impact electric resource costs by decreasing hydroelectric generation capability and increasing the costs for fuel to run thermal generation. This also increases the need for cash to purchase electric resources in the wholesale market. Regional precipitation and snowpack conditions typically have a significant effect on the wholesale price of electricity. In addition, high demand for electricity will generally increase the cost of fuel for electric generation and wholesale electric market prices.

Our hydroelectric generation was 104 percent of normal in 2006. For 2007, we are forecasting hydroelectric generation to be normal. This 2007 forecast will be revised based on precipitation, temperatures and other variables during the year.

We are subject to electric and natural gas commodity price risk. In general, price risk is the risk of fluctuation in the market price of the commodity needed, held or traded. Changes in energy commodity prices have a significant effect on our liquidity, as well as the market value of derivative assets and liabilities and unrealized gains and losses. Our utility operation has regulatory mechanisms in place that provide for the deferral and recovery of the majority of power and natural gas supply costs. However, if prices increase above the level currently recovered in retail rates during periods when we must purchase energy, power and natural gas deferral balances will increase. This would negatively affect operating cash flows and liquidity until such costs, with interest, are recovered from customers.

Our utility net income was $19.9 million for the three months ended March 31, 2007, a decrease from $26.2 million for the three months ended March 31, 2006 primarily due to a decrease in gross margin (operating revenues less resource costs). The decrease was also due to an increase in other operating expenses and taxes other than income taxes, partially offset by a decrease in interest expense. The decrease in gross margin was primarily due to an increase in electric resource costs as compared to the amount included in base retail rates. We recognized an expense of $3.2 million under the Washington Energy Recovery Mechanism (ERM) for the three months ended March 31, 2007 compared to a benefit of $5.2 million under the ERM for the three months ended March 31, 2006.

We plan to continue to invest in generation, transmission and distribution systems with a focus on providing reliable service to our customers. Utility capital expenditures were $40.6 million for the three months ended March 31, 2007. We are expecting utility capital expenditures to be $180 million for 2007. Significant projects include the continued enhancement of our transmission system and upgrades to our generation facilities.

We are not expecting to receive any general rate increases in 2007 and we expect to absorb expenses under the ERM in 2007 as compared to a benefit in 2006. Based primarily on these factors, utility net income may decrease for 2007 as compared to 2006. We filed a general rate case in Washington in April 2007 requesting rate increases averaging 15.9 percent for electric and 2.3 percent for natural gas. Any rate adjustments, if approved by the WUTC, would most likely become effective in 2008.

Energy Marketing and Resource Management (Avista Energy)

Given the significant changes in the energy marketplace over the past few years, we explored whether we should continue in this business over the long term or if any strategic alternatives were available that would allow Avista Energy to grow and reach its earnings potential. As such, we reached a decision to sell the majority of this business.

The activities of Avista Energy include:

- trading electricity and natural gas,
- the optimization of generation assets owned by other entities,
- long-term electric supply contracts,
- natural gas storage, and
- electric transmission and natural gas transportation arrangements.

Avista Energy Canada, Ltd. (Avista Energy Canada) is a wholly owned subsidiary of Avista Energy that provides natural gas services to end-user industrial and commercial customers in British Columbia, Canada.

Our earnings and cash flows from this business segment are by nature subject to significant variability because they are derived primarily from the day-to-day trading of electricity and natural gas and optimization of assets owned by other entities, rather than predictable long-term revenue streams. Also, these activities are for the most part subject to mark-to-market accounting. However, this is different from the required accounting for natural gas storage and certain other assets and contracts. As such, our earnings from Avista Energy are subject to variability caused by the differences between the estimated market value and the required accounting for these assets and contracts.

Primarily through Avista Energy, we are involved in a number of legal and regulatory proceedings and complaints with respect to power markets in the western United States that remain unresolved. However, we believe that we have adequate reserves established for refunds that may be ordered. Any potential refunds or obligations arising from western power market issues (or any other contingent matters) will not be assumed by Coral Energy.

The Energy Marketing and Resource Management segment had a net loss of $7.6 million for the three months ended March 31, 2007 compared to net income of $5.0 million for the three months ended March 31, 2006. These lower results from Avista Energy were primarily due to underperformance on the power side of the business and losses on a power purchase agreement related to a natural gas-fired combined cycle combustion turbine plant in northern Idaho

(Lancaster Plant). The difference between the estimated market value and the required accounting for certain contracts and physical assets under management increased the net loss by $3.5 million from this segment for the three months ended March 31, 2007 and increased net income by $2.6 million for the three months ended March 31, 2006.

Advantage IQ

Our subsidiary, Advantage IQ, had net income of $1.6 million for the three months ended March 31, 2007, an increase from $1.4 million for the three months ended March 31, 2006, primarily due to increased operating revenues. This was a result of customer growth and an increase in interest earnings on funds held for customers.

We are implementing certain strategic investments at Advantage IQ aimed at creating long-term savings that will increase operating and capitalized costs in the short term through up-front expenditures. This could limit earnings growth from this segment in 2007 while enhancing the long-term profit potential of Advantage IQ.

Other Business Segment

Over time as opportunities arise, we plan to dispose of assets and phase out operations in the Other business segment. However, we may invest incremental funds in these businesses to protect existing investments. Net income in our Other business segment was $0.2 million for the three months ended March 31, 2007, compared to a net loss of $1.1 million for the three months ended March 31, 2006. This improvement in results was primarily due to net gains on certain long-term venture fund investments in 2007 as compared to net losses in 2006. We are not expecting a significant change in results from this business segment for 2007 as compared to 2006.

Liquidity and Capital Resources

We have a committed line of credit in the total amount of $320.0 million with an expiration date of April 2011. No borrowings were outstanding under the committed line of credit at March 31, 2007.

In March 2007, we amended our accounts receivable sales facility to extend the termination date to March 2008. Under this facility, we can sell without recourse, on a revolving basis, up to $85.0 million of accounts receivable.

Avista Energy has a $145.0 million committed line of credit that expires in July 2007 and expects to extend this credit agreement if necessary and terminate the facility with the closing of the sale of contracts and ongoing operations to Coral Energy.

In December 2006, we entered into a sales agency agreement with a sales agent to issue up to 2 million shares of our common stock from time to time. Due to the expected proceeds from the sale and liquidation of Avista Energy’s assets, we are not currently planning to issue any shares under this agreement.

For 2007, we expect net cash flows from operating activities, proceeds from the sale and liquidation of Avista Energy’s assets and our $320.0 million committed line of credit to provide adequate resources to fund:

- capital expenditures,
- maturing long-term debt and preferred stock,
- dividends, and
- other contractual commitments.

Succession Planning

We have management succession plans that work towards ensuring that executive officer and key management positions can be appropriately filled as vacancies occur. We also have workforce development plans for key technical and craft areas.

On February 9, 2007, Gary G. Ely, Chairman of the Board and Chief Executive Officer of Avista Corp., announced to the Company’s board of directors that he will retire from the Company and the board, effective December 31, 2007. Following Mr. Ely’s announcement, the Company’s board of directors appointed Scott L. Morris, President and Chief Operating Officer of Avista Corp., to serve as a director on the board. The Company’s board of directors also elected Mr. Morris to the positions of Chairman of the Board and Chief Executive Officer of Avista Corp., effective January 1, 2008.

On April 23, 2007, the Company announced that Ronald R. Peterson, Vice President of Avista Corp. and Vice President of Energy Resources and Optimization of Avista Utilities will retire from the Company on August 1, 2007. Dennis Vermillion, President and Chief Operating Officer of Avista Energy, has been named Vice President of Energy Resources and Optimization of Avista Utilities effective upon the closing of the sale of the contracts and ongoing operations of Avista Energy to Coral Energy. This is expected to occur late in the second quarter or early in the third quarter of 2007.

Avista Utilities – Regulatory Matters

General Rate Cases

In recent years, we have generally not earned our authorized rates of return in our regulated utility operations. We regularly review the need for electric and natural gas rate changes in each state in which we provide service. We will continue to file for rate adjustments to:

- provide for recovery of operating costs and capital investments, and
- more closely align earned returns with those allowed by regulators.

With regards to the timing and plans for future filings, the assessment of our need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include in-service dates of major infrastructure investments and the timing of changes in major revenue and expense items.

We filed a general rate case in Washington in April 2007. In the general rate case, we have requested to increase electric rates for our Washington customers by an average of 15.9 percent, which is intended to increase annual revenues by $51.1 million. We have also requested to increase natural gas rates by an average of 2.3 percent, which is intended to increase annual revenues by $4.5 million. Our request is based on a proposed rate of return of 9.39 percent with a common equity ratio of 47.8 percent and an 11.3 percent return on equity. The WUTC generally has up to 11 months to review the general rate case filing.

The following is a summary of our authorized rates of return in each jurisdiction:

Jurisdiction and service	Implementation Date	Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
Washington electric and natural gas	January 2006	9.11%	10.40%	40%
Idaho electric and natural gas	September 2004	9.25%	10.40%	43%
Oregon natural gas	October 2003	8.88%	10.25%	48%

As part of the general rate case settlement agreement that was modified and approved by the WUTC Order in December 2005, we agreed to increase the utility equity component to 35 percent by the end of 2007 and 38 percent by the end of 2008. If we do not meet those targets, it could result in a reduction to base rates of 2 percent for each target. The calculation of the utility equity component is essentially the ratio of our total consolidated common equity to total capitalization excluding, in each case, our investment in Avista Capital. The utility equity component was 39.5 percent as of March 31, 2007. We should be able to meet these equity targets through expected earnings and proceeds from the Avista Energy transaction.

Oregon Senate Bill 408

The Public Utility Commission of Oregon (OPUC) issued final rules related to Oregon Senate Bill 408 (OSB 408). OSB 408 was enacted into law in 2005. These rules direct the utility to establish an automatic adjustment clause to account for the difference between income taxes collected in rates and taxes paid to units of government, net of adjustments, when that difference exceeds $100,000. The automatic adjustment clause may result in either rate increases or rate decreases and applies only to taxes paid and collected on or after January 1, 2006.

The final rules provide for an "apportionment method" that uses a three-factor formula consisting of property, payroll and sales for regulated operations of the utility in Oregon as the numerator, and these same factors for the consolidated company as the denominator, to determine the amount of consolidated taxes paid that are properly attributed to Oregon operations. Under the new rules, we will determine the least of:

- the properly attributed amount of taxes paid using the apportionment method,
- the amount of taxes determined on a stand-alone basis for Oregon operations, and
- total consolidated taxes paid.

We will then compare this amount to taxes collected in rates to determine if a refund or surcharge is required.

As required by OPUC orders, we (along with other utilities in Oregon) filed a private letter ruling request with the Internal Revenue Service in December 2006. The private letter ruling request seeks guidance on whether OSB 408 and the related OPUC orders violate normalization rules for accounting for income taxes. Certain parties (including Avista Corp.) are seeking legislative changes related to OSB 408. Based on an analysis of operating results for prior years and current rules, we recorded a liability for potential refunds to our customers of $1.3 million for 2006 and $0.3 million for the first quarter of 2007.

Natural Gas Decoupling

In February 2007, the WUTC approved the implementation of a natural gas decoupling mechanism. Decoupling separates the direct link between natural gas sales volume and the recovery of the fixed cost of providing service to our customers. Because our rate structure provides for recovery of the majority of fixed costs on a per-therm (sales volume) basis, energy efficiency and conservation objectives have been directly at odds with the recovery of fixed costs, which do not vary with the volume of natural gas sold. Our decoupling mechanism should allow us to recover lost margin resulting from lower usage by Washington customers due to conservation and price elasticity. However, it will not provide rate adjustments related to abnormal weather. The decoupling mechanism is a three-year “pilot” that began in January 2007. A rate adjustment in any one year would be limited to no more than 2 percent. The filing of the first decoupling rate adjustment will be in the fall of 2007.

Accounting Order for Debt Repurchase Costs

The WUTC staff raised questions and requested information regarding our method of amortization of costs related to debt repurchased between 2002 and 2006. After discussions with the WUTC staff, we agree that the costs associated with debt repurchases beginning in 2002 should have been accounted for in accordance with FERC General Instruction 17 (FERC 17). In February 2007, we filed a request with the WUTC for an accounting order approving our current accounting treatment for debt repurchase costs. In April 2007, the WUTC indicated that this issue will be addressed in a general rate case filing and we have included this request within our general rate case filing. In the April general rate case filing, we agreed that costs associated with any new repurchases of debt would be accounted for in accordance with FERC General Instruction 17 (FERC 17), and in the event we desire to account for the cost of new debt repurchases differently than prescribed in FERC 17, we would request an accounting order from the WUTC prior to the repurchase. Under FERC 17, debt repurchase costs are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs can be amortized over the life of the new debt. We have amortized debt repurchase costs over the average remaining maturity of outstanding debt and these costs are currently recovered through retail rates as a component of interest expense. In our request for an accounting order, we are not proposing to change the amortization method for debt repurchase costs incurred prior to December 31, 2006.

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used to track certain differences between actual power supply costs and the amount included in base retail rates for our Washington customers. This difference in power supply costs primarily results from changes in:

- short-term wholesale market prices,
- the level of hydroelectric generation, and
- the level of thermal generation (including changes in fuel prices).

The initial amount of power supply costs in excess or below the level in retail rates, which we either incur the cost of, or receive the benefit from, is referred to as the deadband. The annual deadband amount is currently $4.0 million. We will incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. We will share annual power supply cost variances between $4.0 million and $10.0 million with customers. As such, 50 percent of the annual power supply cost variance in this range is deferred for future surcharge or rebate to customers and we will incur the cost of, or receive the benefit from, the remaining 50 percent. Once the annual power supply cost variance from the amount included in base rates exceeds $10.0 million, 90 percent of the cost variance is deferred for future surcharge or rebate. We will incur the cost of, or receive the benefit from, the remaining 10 percent of the annual variance beyond $10.0 million without affecting current or future customer rates. The following is a summary of the ERM:

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
+/- $0—$4 million	0%	100%
+/- between $4 million—$10 million	50%	50%
+/- excess over $10 million	90%	10%

Under the ERM, we make an annual filing on or before April 1st of each year to provide the opportunity for the WUTC and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. The ERM provides for a 90-day review period for the filing; however, the period may be extended by agreement of the parties or by WUTC order.

We have a PCA mechanism in Idaho that allows us to modify electric rates periodically with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. The PCA rate surcharge is currently 2.5 percent.

The following table shows activity in deferred power costs for Washington and Idaho during the three months ended March 31, 2007 (dollars in thousands):

	Washington	Idaho	Total
Deferred power costs as of December 31, 2006	$ 70,159	$ 9,357	$ 79,516
Activity from January 1 – March 31, 2007:			
Power costs deferred	—	3,797	3,797
Interest and other net additions	831	182	1,013
Recovery of deferred power costs through retail rates	(9,140)	(1,319)	(10,459)
Deferred power costs as of March 31, 2007	$ 61,850	$ 12,017	$ 73,867

Purchased Gas Adjustments

Effective November 1, 2006, natural gas rates:

- increased 1.3 percent in Washington,
- decreased 3.4 percent in Idaho, and
- increased 6.9 percent in Oregon.

These natural gas rate increases and decreases are designed to pass through changes in purchased natural gas costs to our customers with no change in gross margin or net income. The increase in Oregon was approved subject to refund pending further review of our natural gas purchasing and hedging strategies. We have entered into a settlement agreement with the OPUC staff and the Northwest Industrial Gas Users related to this review, which is subject to approval by the OPUC. Total deferred natural gas costs were $10.2 million as of March 31, 2007, a decrease from $18.3 million as of December 31, 2006 primarily due to recovery from customers during the first quarter of 2007.

Legal and Regulatory Proceedings in Western Power Markets

We are involved in a number of legal and regulatory proceedings and complaints with respect to power markets in the western United States. Most of these proceedings and complaints relate to the significant increase in the spot market price of energy in western power markets in 2000 and 2001, which allegedly contributed to or caused unjust and unreasonable prices. These proceedings and complaints include, but are not limited to:

- refund proceedings in California and the Pacific Northwest,
- market conduct investigations by the FERC, and
- complaints filed by various parties related to alleged misconduct by other parties in western power markets.

As a result of these proceedings and complaints, certain parties have asserted claims for refunds and damages from us (primarily through Avista Energy), which could result in a negative effect on future earnings. However, we believe that we have adequate reserves established for refunds that may be ordered. We have joined other parties in opposing these refund claims and complaints for damages. See further information in "Note 12 of the Notes to Consolidated Financial Statements." Any potential refunds or obligations of Avista Energy arising from western power market issues (or any other contingent matters) will not be assumed by Coral Energy.

Results of Operations

The following provides an overview of changes in our Consolidated Statements of Income. More detailed explanations are provided, particularly for operating revenues and operating expenses in the business segment discussions (Avista Utilities, Energy Marketing and Resource Management, Advantage IQ and Other) that follow this section.

Utility revenues decreased $9.0 million to $414.3 million due to a decrease in electric revenues of $31.8 million reflecting decreased wholesale revenues and sales of fuel, partially offset by increased retail revenues. This was partially offset by increased natural gas revenues of $22.8 million due to increased wholesale (primarily due to increased volumes) and retail (due to an increase in rates and volumes) natural gas sales.

Non-utility energy marketing and trading revenues decreased $32.1 million to $29.4 million primarily due to a decrease of $24.9 million in net trading margin on contracts accounted for under SFAS No. 133, as amended, and a $7.2 million decrease from sales of natural gas to commercial and industrial end-user customers (both through Avista Energy Canada and to Montana customers).

Other non-utility revenues increased $1.1 million to $15.5 million as a result of increased revenues from Advantage IQ of $1.9 million primarily due to customer growth as well as an increase in interest earnings on funds held for customers. This was partially offset by decreased revenues from the Other business segment of $0.8 million primarily due to decreased sales at AM&D.

Utility resource costs decreased $1.6 million primarily due to a decrease in electric resource costs of $22.3 million reflecting a decrease in other fuel costs (economic sales of fuel that was not used in generation) and purchased power costs. These decreases are consistent with reduced resource optimization activities and lower sales of fuel and wholesale sales as part of the process of balancing loads and resources. The decrease in electric resource costs was partially offset by an increase in natural gas resource costs of $20.7 million primarily reflecting an increase in the volume of purchases.

Utility other operating expenses increased $3.3 million primarily due to increased employee compensation expense and outside services.

Utility taxes other than income taxes increased $1.9 million primarily due to increased retail electric and natural gas revenues and related taxes.

Non-utility resource costs decreased $12.4 million primarily due to decreased resource costs related to sales of natural gas to commercial and industrial end-user customers, and decreased transportation and transmission costs.

The net change in other non-utility operating expenses was an increase of $0.8 million due to:

- an increase of $0.3 million in the Energy Marketing and Resource Management segment due to necessary adjustments to reduce the carrying value of net assets to be sold to their estimated fair value less costs to sell, offset by decreased incentive compensation based on lower earnings,
- an increase of $1.7 million for Advantage IQ due to expanding operations, and
- a decrease of $1.2 million in the Other business segment due to lower operating expense at AM&D and the accrual of an environmental liability at Avista Development during the first quarter of 2006.

Interest expense decreased $1.8 million primarily due to our issuance of fixed rate long-term debt that replaced maturing debt (which had relatively high interest rates) in the fourth quarter of 2006, as well as a decrease in the amount of short-term borrowings outstanding.

Capitalized interest increased $0.6 million due to increased utility construction activity and the associated increase in construction work in progress balances.

Other income-net increased $1.2 million due to an increase in interest income and gains on long-term venture fund investments (Other segment), partially offset by a decrease in interest on power and natural gas deferrals.

Income taxes decreased $11.0 million primarily due to decreased income before income taxes. Our effective tax rate was 34.7 percent for the three months ended March 31, 2007 compared to 37.0 percent for the three months ended March 31, 2006.

Avista Utilities

Net income for the utility was $19.9 million for the three months ended March 31, 2007 compared to $26.2 million for the three months ended March 31, 2006. Utility income from operations was $50.2 million for the three months ended March 31, 2007 compared to $62.9 million for the three months ended March 31, 2006. This decrease in income from operations was primarily due to decreased gross margin (operating revenues less resource costs). The decrease was also due to:

- an increase in utility taxes other than income taxes (primarily due to increased retail electric and natural gas revenues and related taxes), and
- an increase in other utility operating expenses (primarily employee compensation and outside services).

The following table presents our utility gross margin for the three months ended March 31 (dollars in thousands):

	Electric		Natural Gas		Total	
	2007	2006	2007	2006	2007	2006
Operating revenues	$ 190,168	$ 222,008	$ 224,098	$ 201,282	$ 414,266	$ 423,290
Resource costs	92,064	114,404	177,922	157,201	269,986	271,605
Gross margin	$ 98,104	$ 107,604	$ 46,176	$ 44,081	$ 144,280	$ 151,685

Utility operating revenues decreased $9.0 million and utility resource costs decreased $1.6 million, which resulted in a decrease of $7.4 million in gross margin. The gross margin on electric sales decreased $9.5 million and the gross margin on natural gas sales increased $2.1 million. The decrease in our electric gross margin was primarily due to an increase in electric resource costs as compared to the amount included in base retail rates resulting in the expense of $3.2 million (of the $4.0 million deadband) of power supply costs in Washington above the amount included in base retail rates during the first quarter of 2007. In the first quarter of 2006, we received a benefit of $5.2 million under the ERM. The increase in power supply costs for 2007 (as compared to the amount included in base rates) was primarily a result of higher fuel costs and greater use of our thermal generating resources (particularly Coyote Springs 2) to meet higher demand in January and February. The increase in natural gas gross margin was primarily due to colder weather in 2007 and customer growth.

The following table presents our utility electric operating revenues and megawatt-hour (MWh) sales for the three months ended March 31 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2007	2006	2007	2006
Residential	$ 73,096	$ 68,747	1,107	1,042
Commercial	55,111	52,594	771	735
Industrial	22,247	22,774	493	509
Public street and highway lighting	1,406	1,279	6	6
Total retail	151,860	145,394	2,377	2,292
Wholesale	26,308	39,152	342	474
Sales of fuel	8,143	30,937	—	—
Other	3,857	6,525	—	—
Total	$ 190,168	$ 222,008	2,719	2,766

Retail electric revenues increased $6.5 million due to an increase in:

- total MWhs sold (increased revenues $5.4 million) primarily due to customer growth and partially due to an increase in use per customer, and
- revenue per MWh (increased revenues $1.1 million) due to a slight change in revenue mix with a lower percentage of industrial sales.

The increase in use per customer was primarily due to colder weather.

Wholesale electric revenues decreased $12.8 million due to a decrease in sales:

- volumes (decreased revenues $10.2 million) consistent with decreased wholesale purchases and decreased resource optimization activities, and
- prices (decreased revenues $2.6 million).

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market as sales of fuel. Sales of fuel decreased $22.8 million as a greater percentage of our fuel purchases were used in generation.

Other electric revenues decreased $2.7 million primarily as a result of revenues of $3.0 million from the sale of claims we had against Enron Corporation and certain of its affiliates received in the first quarter of 2006, partially offset by increased transmission revenues.

The following table presents our utility natural gas operating revenues and therms delivered for the three months ended March 31 (dollars and therms in thousands):

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2007	2006	2007	2006
Residential	$ 112,539	$ 105,133	83,863	81,062
Commercial	61,378	58,093	49,923	48,723
Interruptible	1,588	1,708	1,561	1,673
Industrial	2,068	2,027	1,881	1,876
Total retail	177,573	166,961	137,228	133,334
Wholesale	43,534	31,215	65,463	45,894
Transportation	1,675	1,608	43,805	42,183
Other	1,316	1,498	238	212
Total	$ 224,098	$ 201,282	246,734	221,623

Natural gas revenues increased $22.8 million due to an increase in retail and wholesale natural gas revenues. The $10.6 million increase in retail natural gas revenues was due to higher retail rates (increased revenues $5.6 million) and increased volumes (increased revenues $5.0 million). We sold more retail natural gas in the first quarter of 2007 primarily due to an increase in use per customer (due to colder weather) and customer growth. The increase in our wholesale revenues of $12.3 million was due to an increase in volumes (increased revenues $13.0 million), partially offset by a decrease in prices (decreased revenues $0.7 million). Wholesale sales reflect the balancing of loads and resources and the sale of resources in excess of load requirements as part of the natural gas procurement process.

The following table presents our average number of electric and natural gas retail customers for the three months ended March 31:

	Electric Customers		Natural Gas Customers	
	2007	2006	2007	2006
Residential	305,728	299,491	273,109	266,450
Commercial	38,334	37,797	32,245	31,724
Interruptible	—	—	41	40
Industrial	1,368	1,394	259	260
Public street and highway lighting	424	430	—	—
Total retail customers	345,854	339,112	305,654	298,474

The following table presents our utility resource costs for the three months ended March 31 (dollars in thousands):

	2007	2006
Electric resource costs:		
Power purchased	$ 39,879	$ 43,918
Power cost amortizations, net of deferrals	6,662	10,179
Fuel for generation	34,131	25,327
Other fuel costs	10,896	34,457
Other regulatory amortizations, net	(2,354)	(2,033)
Other electric resource costs	2,850	2,556
Total electric resource costs	92,064	114,404
Natural gas resource costs:		
Natural gas purchased	166,340	146,743
Natural gas amortizations, net of deferrals	8,490	9,463
Other regulatory amortizations, net	3,092	995
Total natural gas resource costs	177,922	157,201
Total resource costs	$ 269,986	$ 271,605

Power purchased decreased $4.0 million due to a decrease in the volume of power purchases (decreased costs $9.6 million) primarily due to increased thermal generation as well as decreased resource optimization activities as part of the process of balancing loads and resources. This was consistent with a decrease in wholesale sales. This was partially offset by an increase in the price of power purchases (increased costs $5.6 million) due to overall increases in wholesale markets.

Net amortization of deferred power costs was $6.7 million for the three months ended March 31, 2007 compared to $10.2 million for the three months ended March 31, 2006. During the first quarter of 2007, we recovered (collected as revenue) $9.1 million of previously deferred power costs in Washington and $1.3 million in Idaho. During the first quarter of 2007, we deferred $3.8 million of power costs in Idaho above the amount included in base retail rates. We did not defer any power costs in Washington during the first quarter of 2007, as power supply costs were within the $4.0 million deadband under the ERM.

Fuel for generation increased $8.8 million due to higher natural gas fuel prices and an increase in thermal generation volumes (particularly Coyote Springs 2).

Other fuel costs decreased $23.6 million. This represents fuel that was purchased for generation, but was later sold when conditions indicated that it was not economic to use the fuel in generation as part of the resource optimization process. The associated revenues are reflected as sales of fuel. Other fuel costs exceeded revenues we received from selling the natural gas. We account for this shortfall under the ERM in Washington and the PCA in Idaho. The decrease in other fuel costs was primarily due to an increased percentage of fuel used in generation.

The expense for natural gas purchased for sale to customers increased $19.6 million primarily due to an increase in total therms purchased. This was primarily due to an increase in wholesale sales as part of the balancing of loads and resources as part of the natural gas procurement process, and partially due to a slight increase in retail sales volumes. During the first quarter of 2007, we amortized $8.5 million of deferred natural gas costs compared to $9.5 million for the first quarter of 2006.

Energy Marketing and Resource Management

The Energy Marketing and Resource Management segment primarily includes the results of Avista Energy. In April 2007, Avista Energy entered into a purchase and sale agreement to sell substantially all of its contracts and ongoing operations.

Earnings from Avista Energy are derived from the following activities:

- taking speculative positions on future price movements within established risk management policies,
- optimizing generation assets owned by other entities,
- capturing price differences between commodities (spark spread) by converting natural gas into electricity through the power generation process,
- purchasing and storing natural gas for later sales to seek gains from seasonal price variations and demand peaks,
- transmitting electricity and transporting natural gas between locations, including moving energy from lower priced/demand regions to higher priced/demand markets and hub locations, and
- marketing natural gas to end-user industrial and commercial customers.

Avista Energy reports the net margin on derivative commodity instruments held for trading as operating revenues. Revenues from contracts that are not derivatives under SFAS No. 133 and derivative commodity instruments not held for trading are reported on a gross basis in operating revenues. Costs from contracts that are not derivatives under SFAS No. 133 and derivative commodity instruments not held for trading, are reported on a gross basis in resource costs.

The following table presents our net realized gains and net unrealized gains (losses) from Avista Energy for the three months ended March 31 (dollars in thousands):

	2007	2006
Net realized gains	$ 12,615	$ 5,275
Net unrealized gains (losses)	(20,933)	6,140
Total gross margin (operating revenues less resource costs)	$ (8,318)	$ 11,415

Overall segment results

The Energy Marketing and Resource Management segment had a net loss of $7.6 million for the three months ended March 31, 2007 compared to net income of $5.0 million for the three months ended March 31, 2006. These lower results from Avista Energy were primarily due to underperformance on the power side of the business and losses on a power purchase agreement related to the Lancaster Plant. The difference between the estimated market value and the required accounting for certain contracts and physical assets under management accounted for $3.5 million of Avista Energy's net loss for the first quarter of 2007. Our net income for the first quarter of 2006 for this segment was increased by an estimated $2.6 million due to the effects of differences between the estimated market value and the required accounting for certain energy contracts and physical assets under management of Avista Energy.

Differences in the estimated market value and the required accounting for certain contracts and physical assets under management

Earnings from this segment are affected by the variability associated with the difference between the estimated market value and the required accounting for certain contracts and physical assets under management of Avista Energy as disclosed above. These operations are managed on an economic basis reflecting contracts and assets under management at estimated market value. Under SFAS No. 133, certain contracts, which are considered derivatives, economically hedge other contracts and physical assets under management, which are not considered derivatives. Our derivative contracts are generally recorded at estimated market value. Non-derivative contracts are generally accounted for at the lower of cost or market value. The accounting treatment does not affect the underlying cash flows or economics of our transactions. This difference between the estimated market value and the required accounting are generally reversed in future periods when market values change or when our contracts are settled or realized. However, the amount of the difference could increase or decrease prior to settlement due to changes in forward market prices. This primarily relates to Avista Energy's management of natural gas inventory and its control of natural gas-fired generation through a power purchase agreement related to the Lancaster Plant. Please refer to the 2006 Form 10-K for a detailed discussion of these differences.

AVISTA CORPORATION

Analysis of operating revenues, resource costs and gross margin

Operating revenues decreased $32.1 million due to a decrease of $24.9 million in net trading margin on contracts accounted for under SFAS No. 133 and a $7.2 million decrease from sales of natural gas to commercial and industrial end-user customers (both through Avista Energy Canada and to Montana customers).

Resource costs decreased $12.4 million primarily due to decreased resource costs related to sales of natural gas to commercial and industrial end-user customers, as well as decreased transportation and transmission costs.

Our gross margin (operating revenues less resource costs) from Avista Energy was a loss of $8.3 million for the three months ended March 31, 2007 compared to a gain of $11.4 million for the three months ended March 31, 2006. The decrease was primarily due to underperformance on the power side of the business, losses on the power purchase agreement for the Lancaster Plant, and the difference between the estimated market value and the required accounting for certain contracts and physical assets under management.

Our net realized gains from Avista Energy increased to $12.6 million for the three months ended March 31, 2007 from $5.3 million for the three months ended March 31, 2006. The increase in net realized gains was primarily due to increased net gains on settled financial transactions and decreased transmission and transportation fees.

Our total mark-to-market adjustment from this segment was a net unrealized loss of $20.9 million for the three months ended March 31, 2007 compared to a net unrealized gain of $6.1 million for the three months ended March 31, 2006.

Energy trading activities and positions

The following table summarizes information for trading activities at Avista Energy during the three months ended March 31, 2007 (dollars in thousands):

	Electric Assets net of Liabilities	Natural Gas Assets net of Liabilities	Total Unrealized Gain (Loss)
Fair value of contracts as of December 31, 2006	$ 34,044	$ (507)	$ 33,537
Less contracts settled during 2007 (1)	(13,106)	491	(12,615)
Fair value of new contracts when entered into during 2007 (2)	—	—	—
Change in fair value due to changes in valuation techniques (3)	—	—	—
Change in fair value attributable to market prices and other market changes	(3,729)	(2,780)	(6,509)
Fair value of contracts as of March 31, 2007	$ 17,209	$ (2,796)	$ 14,413

(1) Contracts settled during 2007 include those contracts that were open in 2006 but settled during the three months ended March 31, 2007 as well as new contracts entered into and settled during 2007. Amount represents net realized gains associated with these settled transactions.

(2) We did not enter into any origination transactions during the three months ended March 31, 2007 in which we recognized any dealer profit or mark-to-market gain or loss at inception.

(3) During the three months ended March 31, 2007, we did not experience a change in fair value due to changes in valuation techniques.

The following table discloses summarized information related to valuation techniques and contractual maturities of energy commodity contracts at Avista Energy outstanding as of March 31, 2007 (dollars in thousands):

	Less than one year	Greater than one and less than three years	Greater than three and less than five years	Greater than five years	Total
Electric assets (liabilities), net					
Prices from other external sources (1)	$ 12,829	$ 24,599	$ —	$ —	$ 37,428
Fair value based on valuation models (2)	(873)	(720)	(835)	(17,791)	(20,219)
Total electric assets (liabilities), net	$ 11,956	$ 23,879	$ (835)	$ (17,791)	$ 17,209
Natural gas assets (liabilities), net					
Prices from other external sources (1)	$ (2,939)	$ 1,856	$ —	$ —	$ (1,083)
Fair value based on valuation models (3)	(897)	(770)	(46)	—	(1,713)
Total natural gas assets (liabilities), net	$ (3,836)	$ 1,086	$ (46)	$ —	$ (2,796)

(1) We determined fair value based upon actively traded, “over-the-counter” market quotes received from third party brokers. These market quotes are used through 36 months.

(2) Represents contracts for delivery at basis locations not actively traded in the “over-the-counter” markets. In addition, this includes all contracts with a delivery period greater than 36 months, for which active quotes are not available. Our internally developed market curves are determined using a production cost model with inputs for assumptions related to power prices (including, without limitation, natural gas prices, generation on-line, transmission constraints, future demand and weather). We perform frequent stress tests on the valuation of the portfolio. While consistent valuation methodologies and updates to the assumptions are used to capture current market information, changes in these methodologies or underlying assumptions could result in significantly different fair values and income recognition. These same pricing techniques and stress tests are used to evaluate a contract prior to taking a position.

(3) Represents contracts for delivery at basis locations not actively traded in the “over-the-counter” markets. In addition, this includes all contracts with a delivery period greater than 36 months, for which active quotes are not available. Our internally developed market curves are based upon published New York Mercantile Exchange prices, as well as basis spreads using historical and broker estimates.

<u>Advantage IQ</u>

Net income for Advantage IQ was $1.6 million for the three months ended March 31, 2007 compared to $1.4 million for the three months ended March 31, 2006. Operating revenues increased $1.9 million and operating expenses increased $1.7 million. The increase in operating revenues was primarily due to the expansion of Advantage IQ’s customer base as well as an increase in interest earnings on funds held for customers. Advantage IQ has over 370 customers representing 211,000 billed sites in North America. The number of billed sites increased by 29,000, or 16 percent, from March 31, 2006. The increase in interest earnings on funds held for customers was due in part to an increase in interest rates. The increase in operating expenses primarily reflects increased labor and other operational costs necessary to serve an expanding customer base.

<u>Other Business Segment</u>

Net income from this business segment was $0.2 million for the three months ended March 31, 2007 compared to a net loss of $1.1 million for the three months ended March 31, 2006. Operating revenues decreased $0.8 million and operating expenses decreased $1.3 million. Net income for AM&D was $0.1 million for each of the first quarter of 2007 and 2006. With respect to overall segment results, the improvement was due to:

- the accrual for an environmental liability in the first quarter of 2006, and
- gains on certain long-term venture fund investments in this segment in the first quarter of 2007 compared to losses in the first quarter of 2006.

<u>New Accounting Standards</u>

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, “Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109,” (FIN 48) which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. We adopted FIN 48 in the first quarter of 2007. The adoption of FIN 48 did not have a cumulative effect on our financial condition and results of operations. See Notes 2 and 8 of the Notes to Consolidated Financial Statements for further information.

In September 2006, the FASB issued SFAS No. 157, “Fair Value Measurements,” which provides enhanced guidance for using fair value to measure assets and liabilities. We will be required to adopt SFAS No. 157 in 2008. We are evaluating the impact SFAS No. 157 will have on our financial condition and results of operations.

In February 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities.” This statement permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected would be reported in net income. We will be required to adopt SFAS No. 159 in 2008. We are evaluating the impact SFAS No. 159 will have on our financial condition and results of operations.

<u>Critical Accounting Policies and Estimates</u>

The preparation of our consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires us to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on our consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein. Our critical accounting policies that require the use of estimates and assumptions were discussed in detail in the 2006 Form 10-K and have not changed materially from that discussion.

Liquidity and Capital Resources

Review of Cash Flow Statement

Overall During the three months ended March 31, 2007, positive cash flows from operating activities of $90.3 million were used to fund the majority of our cash requirements. These cash requirements included utility property capital expenditures of $40.6 million, debt maturities of $12.3 million and dividends of $7.6 million. As cash flows from operating activities and other sources of cash inflows exceeded other funding requirements, our total debt decreased $15.8 million during the first quarter of 2007.

Operating Activities Net cash provided by operating activities was $90.3 million for the three months ended March 31, 2007 compared to $107.1 million for the three months ended March 31, 2006. Net cash provided by working capital components was $26.6 million for the three months ended March 31, 2007, compared to $46.0 million for the three months ended March 31, 2006. The net cash provided during the three months ended March 31, 2007 primarily reflects positive cash flows from:

- accounts receivable (representing net cash received from our customers),
- materials and supplies, fuel stock and natural gas stored (representing the seasonal drawdown of natural gas inventory),
- other current assets (representing a net decrease in income taxes receivable), and
- other current liabilities (representing an increase in interest accrued).

This cash provided was partially offset by negative cash flows from:

- accounts payable (representing net cash paid to our vendors),
- a decrease in the amount outstanding under our revolving accounts receivable sales facility, and
- cash deposits with counterparties (representing cash posted as collateral at Avista Energy).

The net cash provided during the three months ended March 31, 2006 primarily reflected positive cash flows from:

- accounts receivable (representing net cash received from customers),
- other current liabilities (primarily due to an increase in funds held for customers at Avista Advantage), and
- cash deposits with counterparties (representing cash returned that was deposited as collateral funds at Avista Energy).

This was partially offset by a decrease in accounts payable (representing net cash paid to vendors).

Significant non-cash items included $14.9 million of power and natural gas cost amortizations, net of deferrals, for the first quarter of 2007, a decrease from $19.4 million for the first quarter of 2006 primarily due to a decrease in recoveries of previously deferred costs from customers. Significant changes in non-cash items also included a $27.0 million change in the unrealized gain or loss on energy commodity derivatives, representing the change to an unrealized loss of $20.9 million on energy trading activities for the first quarter of 2007 as compared to an unrealized gain of $6.1 million for the first quarter of 2006.

Investing Activities Net cash used in investing activities was $39.2 million for the three months ended March 31, 2007, an increase compared to $16.4 million for the three months ended March 31, 2006. This was primarily due to an increase in utility property capital expenditures in 2007 and other cash inflows in the first quarter of 2006, which included the receipt of $5.5 million from our sale of a claim against an affiliate of Enron Corporation related to the construction of Coyote Springs 2 and proceeds from asset sales of $6.8 million (primarily for a turbine at Avista Power).

Financing Activities Net cash used in financing activities was $22.3 million for the three months ended March 31, 2007 compared to $45.5 million for the three months ended March 31, 2006. During the first quarter of 2007, our short-term borrowings decreased $4.0 million, which reflects a decrease in the amount of debt outstanding under our $320.0 million committed line of credit. Cash dividends paid increased to $7.6 million (or 14.5 cents per share) for the first quarter of 2007 from $6.8 million (or 14 cents per share) for the first quarter of 2006. Debt maturities were $12.3 million for the first quarter of 2007.

During the three months ended March 31, 2006, short-term borrowings decreased $40.0 million, which reflected a decrease in the amount of debt outstanding under our committed line of credit.

AVISTA CORPORATION

Overall Liquidity

Our consolidated operating cash flows are primarily derived from the operations of Avista Utilities and Avista Energy. The primary source of operating cash flows for our utility operations is revenues (including the recovery of previously deferred power and natural gas costs) from sales of electricity and natural gas. Significant uses of cash flows from our utility operations include the purchase of electricity and natural gas, and payment of other operating expenses, taxes and interest. The primary source and use of operating cash flows for Avista Energy is revenues and costs from realized energy commodity transactions as well as cash collateral deposited to or held from counterparties. Significant operating cash outflows for Avista Energy also include other operating expenses and taxes.

Avista Energy has entered into a purchase and sale agreement to sell substantially all of its contracts and ongoing operations to Coral Energy. Proceeds from the sale of Avista Energy's net assets to Coral Energy and liquidation of Avista Energy's remaining net assets (primarily receivables, restricted cash and deposits with counterparties) are expected to result in total proceeds of approximately $175 million. Over time, we plan to redeploy the majority of the proceeds from the transaction into our regulated utility operations by reducing debt and investing in capital assets.

Our operating cash flows do not always fully support the needs for utility capital expenditures. As such, from time to time, we may need to access capital markets in order to fund these needs as well as fund maturing debt. See further discussion at "Capital Resources."

We design operating and capital budgets to control operating costs and capital expenditures, particularly for our regulated utility operations. In addition to operating expenses, we have continuing commitments for capital expenditures for construction, improvement and maintenance of utility facilities.

We will continue to periodically file for rate adjustments for recovery of operating costs and capital investments to provide the opportunity to align our earned returns with those allowed by regulators. We filed a general rate case in Washington in April 2007 requesting general rate increases averaging 15.9 percent for electric and 2.3 percent for natural gas. This is designed to increase annual electric revenues by $51.1 million and annual natural gas revenues by $4.5 million. See further details in the section "Avista Utilities—Regulatory Matters."

With respect to our utility operations, when power and natural gas costs exceed the levels currently recovered from retail customers, net cash flows are negatively affected. Factors that could cause purchased power costs to exceed the levels currently recovered from our customers include, but are not limited to, higher prices in wholesale markets when we are buying energy or an increased need to purchase power in the wholesale markets. Factors beyond our control that could result in an increased need to purchase power in the wholesale markets include, but are not limited to:

- increases in demand (either due to weather or customer growth),
- low availability of streamflows for hydroelectric generation,
- outages at generating facilities, and
- failure of third parties to deliver on energy or capacity contracts.

Our hydroelectric generation was 104 percent of normal in 2006. For 2007, we are forecasting hydroelectric generation to be normal. This 2007 forecast will change based upon precipitation, temperatures and other variables during the year.

We monitor the potential liquidity impacts of increasing energy commodity prices for both our utility operations (Avista Utilities) and our energy marketing and resource management operations (Avista Energy). We believe that we have adequate liquidity to meet the increased cash needs of higher energy commodity prices through our:

- current cash and cash equivalents,
- $320.0 million committed line of credit at Avista Corp. (Avista Utilities), and
- $145.0 million committed line of credit at Avista Energy (through the expected closing of its operations).

Our utility has regulatory mechanisms in place that provide for the deferral and recovery of the majority of power and natural gas supply costs. However, if prices increase, deferral balances will increase, which will negatively affect our cash flow and liquidity until such costs, with interest, are recovered from customers.

Capital Resources

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings, consisted of the following as of March 31, 2007 and December 31, 2006 (dollars in thousands):

	March 31, 2007		December 31, 2006	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 14,607	0.7%	$ 26,605	1.3%
Short-term borrowings	—	—	4,000	0.2
Long-term debt to affiliated trusts	113,403	5.6	113,403	5.6
Long-term debt	950,053	46.8	949,854	46.6
Total debt	1,078,063	53.1	1,093,862	53.7
Preferred stock-cumulative (including current portion)	26,250	1.3	26,250	1.3
Total liabilities	1,104,313	54.4	1,120,112	55.0
Stockholders' equity	927,274	45.6	916,846	45.0
Total	$ 2,031,587	100.0%	$ 2,036,958	100.0%

Our total debt decreased $15.8 million during the first quarter of 2007 primarily due to:

- the payment of maturing debt with operating cash flows and other sources of funds, and
- a decrease in the amount outstanding on our committed line of credit.

We need to finance capital expenditures and obtain additional working capital from time to time. The cash requirements needed to service our indebtedness, both short-term and long-term, reduces the amount of cash flow available to fund working capital, purchased power and natural gas costs, capital expenditures, dividends and other requirements. Our stockholders' equity increased $10.4 million during the first quarter of 2007 primarily due to net income and other comprehensive income, partially offset by dividends.

We generally fund capital expenditures with a combination of internally generated cash and external financing. The level of cash generated internally and the amount that is available for capital expenditures fluctuates depending on a variety of factors. Cash provided by our utility operating activities and cash generated by the Avista Energy transaction (including the sale of net assets to Coral Energy and liquidation of net current assets not sold to Coral Energy) are expected to be the primary sources of funds for operating needs, dividends, capital expenditures, as well as maturing long-term debt and preferred stock for 2007. Borrowings under our $320.0 million committed line of credit may supplement these funds to the extent necessary.

We have $358 million of long-term debt maturities and mandatory preferred stock redemptions in 2007 and 2008. Our forecasts indicate that we will need to issue new securities to fund a portion of these requirements in 2008. Proceeds from the expected Avista Energy transaction should reduce our need to issue new securities in 2008. In 2004, we entered into forward-starting interest rate swap agreements effectively locking in market fixed interest rates, which were relatively low compared to historical interest rates, for $125 million of our forecasted debt issuances in 2008.

We have a $320.0 million committed line of credit agreement with various banks with an expiration date of April 5, 2011. Under the agreement, we can request the issuance of up to $320.0 million in letters of credit. As of March 31, 2007, we did not have any borrowings outstanding, a decrease from $4.0 million as of December 31, 2006. As of March 31, 2007, there were $45.3 million in letters of credit outstanding, a decrease from $77.1 million as of December 31, 2006. The committed line of credit is secured by $320.0 million of non-transferable First Mortgage Bonds issued to the agent bank. Such First Mortgage Bonds would only become due and payable in the event, and then only to the extent, that we default on obligations under the committed line of credit.

Our committed line of credit agreement contains customary covenants and default provisions, including a covenant requiring the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Utilities for the preceding twelve-month period at the end of any fiscal quarter to be greater than 1.6 to 1. As of March 31, 2007, we were in compliance with this covenant with a ratio of 2.45 to 1. The committed line of credit agreement also has a covenant which does not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 70 percent at the end of any fiscal quarter. This ratio limitation will be increased to 75 percent during the period between the completion of the proposed change in our corporate organization (see Note 13) and December 31, 2007. As of March 31, 2007, we were in compliance with this covenant with a ratio of 53.1 percent. If the proposed change in organization becomes effective, the committed line of credit agreement will remain at Avista Corp. (Avista Utilities).

Any default on the line of credit or other financing arrangements of Avista Corp. or any of our significant subsidiaries could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Any defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock. We do not guarantee the indebtedness of any of our subsidiaries. As of March 31, 2007, Avista Corp. and our subsidiaries were in compliance with all of the covenants of our financing agreements.

As further discussed at "Avista Utilities - Regulatory Matters," in December 2005, the WUTC issued an order approving the settlement agreement reached in our Washington general rate case with certain conditions. We agreed to increase the utility equity component to 35 percent by the end of 2007 and to 38 percent by the end of 2008. As further discussed at "Note 13 of the Notes to the Consolidated Financial Statements," the IPUC accepted a stipulation that we entered with the IPUC Staff that sets forth a variety of conditions related to the implementation of our holding company structure. One of the conditions provides for the same utility equity components that are required in our Washington general rate case. If we do not meet those targets, it could result in a reduction in base rates of 2 percent for each target in each of Washington and Idaho. We have also entered into a settlement agreement in Washington related to our proposed holding company formation. In this settlement agreement, we have committed to increase the utility equity component to 40 percent by June 30, 2008. However, the provision to reduce base rates by 2 percent does not apply if we fail to meet this target. The utility equity component was 39.5 percent as of March 31, 2007. We should be able to meet these equity targets through expected earnings and proceeds from the Avista Energy transaction.

In December 2006, we entered into a sales agency agreement with a sales agent, to issue up to 2 million shares of our common stock from time to time. Due to the expected proceeds from the sale and liquidation of Avista Energy's assets, we are not currently planning to issue any shares under this agreement.

Off-Balance Sheet Arrangements

Avista Receivables Corporation (ARC) is our wholly owned, bankruptcy-remote subsidiary formed for the purpose of acquiring or purchasing interests in certain of our accounts receivable, both billed and unbilled. On March 19, 2007, Avista Corp., ARC and a third-party financial institution amended a Receivables Purchase Agreement. The most significant amendment was to extend the termination date from March 20, 2007 to March 17, 2008. The Receivables Purchase Agreement was originally entered into on May 29, 2002 and provides us with cost-effective funds for:

- working capital requirements,
- capital expenditures, and
- other general corporate needs.

Under the Receivables Purchase Agreement, ARC can sell without recourse, on a revolving basis, up to $85.0 million of our receivables. ARC is obligated to pay fees that approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of our $320.0 million committed line of credit. As of March 31, 2007, we had sold $68.0 million in accounts receivable under this revolving agreement.

Credit Ratings

The following table summarizes our credit ratings as of May 3, 2007:

	Standard & Poor's	Moody's	Fitch, Inc.
Avista Corporation			
Corporate/Issuer rating	BB+	Ba1	BB
Senior secured debt	BBB-	Baa3	BBB-
Senior unsecured debt	BB+	Ba1	BB+
Preferred stock	BB-	Ba3	BB
Avista Capital II (1)			
Preferred Trust Securities	BB-	Ba2	BB
AVA Capital Trust III (1)			
Preferred Trust Securities	BB-	Ba2	BB
Rating outlook	Positive (2)	Stable	Positive

(1) Only assets are subordinated debentures of Avista Corporation.
(2) Changed to positive from stable in April 2007.

These security ratings are not recommendations to buy, sell or hold securities. The ratings are subject to change or withdrawal at any time by the respective credit rating agencies. Each credit rating should be evaluated independently of any other ratings.

Pension Plan

As of March 31, 2007, our pension plan had assets with a fair value that was less than the benefit obligation under the plan. We contributed $15 million to the pension plan in 2006. We are planning to contribute $15 million to the pension plan in 2007 ($3.75 million was contributed during the first quarter of 2007). Our total pension plan contributions were $73 million from 2002 through the first quarter of 2007.

The Pension Protection Act of 2006 (the Pension Act) was signed into law in August 2006. The Pension Act provides new funding rules for pension plans to improve the funded status of corporate defined benefit plans. The new funding rules could increase our minimum required cash contributions to the pension plan in the future. The legislation is effective in 2008; however, the law contains a transition period related to the funding rules. We do not expect the Pension Act to have a material effect on our financial condition, results of operations or cash flows.

Dividends

The Board of Directors considers the level of dividends on our common stock on a regular basis, taking into account numerous factors including, without limitation:

- our results of operations, cash flows and financial condition,
- the success of our business strategies, and
- general economic and competitive conditions.

Our net income available for dividends is derived primarily from our regulated utility operations (Avista Utilities) and Avista Energy.

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock contained in our Restated Articles of Incorporation, as amended, and to long-term debt contained in various indentures. Covenants under the 9.75 percent Senior Notes that mature in 2008 limit our ability to increase common stock cash dividends to no more than 5 percent over the previous quarter, unless certain conditions are met related to restricted payments. As of March 31, 2007, we are meeting the conditions that would allow us to increase the common stock cash dividend in excess of 5 percent over the previous quarter.

As further discussed at "Note 13 of the Notes to the Consolidated Financial Statements," the IPUC accepted a stipulation that we entered with the IPUC Staff that sets forth a variety of conditions related to the implementation of our holding company structure. One of the conditions requires IPUC approval of any dividend to the holding company that would reduce utility common equity below 25 percent. Furthermore, we have entered into a similar agreement with the WUTC Staff. This agreement would require WUTC approval of any dividend to the holding company that would reduce utility common equity below 30 percent.

Avista Energy holds a significant portion of cash and cash equivalents reflected on our Consolidated Balance Sheets. Covenants in Avista Energy's credit agreement, certain counterparty agreements and market liquidity conditions result in Avista Energy maintaining certain levels of cash and therefore effectively limit the amount of cash dividends that are available for distribution to Avista Capital and ultimately to Avista Corp. Avista Energy's cash and restricted cash will be available for dividends to Avista Capital following the sale of contracts to Coral Energy and the liquidation of Avista Energy's remaining net assets. We are expecting to generate approximately $175 million in cash proceeds from the transaction including the liquidation of Avista Energy's net current assets not sold to Coral Energy (primarily receivables, restricted cash and deposits with counterparties).

Avista Utilities Operations

As of March 31, 2007, we had $2.0 million of restricted cash at Avista Corp. /Avista Utilities. The restricted cash relates to deposits for interest rate swap agreements.

Our utility held cash deposits from other parties in the amount of $38.8 million as of March 31, 2007, which is included in deposits from counterparties on the Consolidated Balance Sheet. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of collateral.

See “Notes 9 and 10 of Notes to Consolidated Financial Statements” for additional details related to our financing activities.

Energy Marketing and Resource Management (Avista Energy) Operations

Avista Energy, and its subsidiary, Avista Energy Canada, as co-borrowers, have a committed credit agreement with a group of banks in the aggregate amount of $145.0 million with an expiration date of July 12, 2007. Avista Energy anticipates that the credit agreement will be extended if necessary and terminated with the closing of the sale of contracts and ongoing operations to Coral Energy. This committed credit facility provides for the issuance of letters of credit to secure contractual obligations to counterparties and for cash advances. This facility is secured by the assets of Avista Energy and Avista Energy Canada, and guaranteed by Avista Capital and by CoPac Management, Inc., a wholly owned subsidiary of Avista Energy Canada. The maximum amount of credit extended by the banks for the issuance of letters of credit is the subscribed amount of the facility less the amount of outstanding cash advances, if any. The maximum amount available for cash advances under the credit agreement is $50.0 million. No cash advances were outstanding as of March 31, 2007. Letters of credit in the aggregate amount of $20.6 million were outstanding as of March 31, 2007. The cash deposits of Avista Energy at the respective banks collateralized these letters of credit as of March 31, 2007, which is reflected as restricted cash on our Consolidated Balance Sheets.

Avista Energy’s credit agreement contains covenants and default provisions, including covenants to maintain “minimum net working capital” and “minimum net worth,” as well as a covenant limiting the amount of indebtedness that the co-borrowers may incur. The credit agreement also contains covenants and other restrictions related to the co-borrowers’ trading limits and positions, including VAR limits, restrictions with respect to changes in risk management policies or volumetric limits, and limits on exposure related to hourly and daily trading of electricity. These covenants, certain counterparty agreements and market liquidity conditions result in Avista Energy maintaining certain levels of cash and therefore effectively limit the amount of cash dividends that are available for distribution to Avista Capital and ultimately to Avista Corp. Avista Energy was in compliance with the covenants of its credit agreement as of March 31, 2007.

Avista Capital provides guarantees for Avista Energy’s credit agreement (see discussion above) and, in the course of business, may provide performance guarantees to other parties with whom Avista Energy may be doing business. At any point in time, Avista Capital is only liable for the outstanding portion of the performance guarantee, which was $32.5 million as of March 31, 2007. The face value of all performance guarantees issued by Avista Capital for energy trading contracts at Avista Energy was $366.9 million as of March 31, 2007.

As part of its cash management practices and operations, Avista Energy from time to time makes unsecured short-term loans to its parent, Avista Capital. Avista Capital’s Board of Directors has limited the total outstanding indebtedness to no more than $45.0 million. Further, as required under Avista Energy’s credit facility, such loans cannot be outstanding longer than 90 days without being repaid. During the first quarter of 2007, Avista Energy’s maximum total outstanding short-term loan to Avista Capital was $26.0 million. As of March 31, 2007, all outstanding loans including accrued interest had been repaid.

Avista Energy manages collateral requirements with counterparties by providing letters of credit, providing guarantees from Avista Capital, depositing cash with counterparties and offsetting transactions with counterparties. Cash deposited with counterparties totaled $85.4 million as of March 31, 2007, an increase from $79.5 million as of December 31, 2006. Avista Energy held cash deposits from other parties in the amount of $2.2 million as of March 31, 2007, which is included in deposits from counterparties on our Consolidated Balance Sheet. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of collateral. Such deposits to and from counterparties will be returned following the sale of Avista Energy’s contracts to Coral Energy.

As of March 31, 2007, Avista Energy had $52.9 million in cash, as well as $24.2 million of restricted cash.

Contractual Obligations

During the three months ended March 31, 2007, our future contractual obligations have not changed materially from the amounts disclosed in the 2006 Form 10-K with the following exceptions:

The amount outstanding under our revolving accounts receivable sales financing facility decreased from $85.0 million as of December 31, 2006 to $68.0 million as of March 31, 2007. In March 2007, the termination date of this facility was extended from March 20, 2007 to March 17, 2008.

Avista Energy's contractual commitments to purchase energy commodities as well as commitments related to transmission, transportation and other energy-related contracts in future periods were as follows as of March 31, 2007 (dollars in millions):

For the 12-month period ended March 31,	2008	2009	2010	2011	2012	Thereafter
Energy purchase contracts	$ 418	$ 263	$ 215	$ 158	$ 35	$ 357

Avista Energy also has sales commitments related to these contractual obligations in future periods. The majority of these contractual commitments will be assumed by Coral Energy.

Business Risk

Our operations are exposed to risks including, but not limited to:

- market prices and supply of wholesale energy, which we purchase and sell, including power, fuel and natural gas,
- regulatory allowance of the recovery of power and natural gas costs, operating costs and capital investments,
- streamflow and weather conditions,
- the effects of changes in legislative and governmental regulations,
- changes in regulatory requirements,
- availability of generation facilities,
- competition,
- technology, and
- availability of funding.

Also, like other utilities, our facilities and operations are exposed to natural disasters and terrorism risks or other malicious acts. See further reference to risks and uncertainties under "Forward-Looking Statements."

Our business risk has not materially changed during the three months ended March 31, 2007. However, our risk profile related to Avista Energy's operations is expected to change with the closing of the sale of contracts and ongoing operations to Coral Energy. Please refer to the 2006 Form 10-K for further description and analysis of business risk including, but not limited to, commodity price, credit, other operating, interest rate and foreign currency risks.

Risk Management

Risk Policies and Oversight

In our utility operation and at Avista Energy, we use a variety of techniques to manage risks for energy resources and wholesale energy market activities. We have risk management policies and procedures to manage these risks, both qualitative and quantitative. Please refer to the 2006 Form 10-K for discussion of risk management policies and procedures.

Quantitative Risk Measurements

Avista Energy measures the risk in its electric and natural gas portfolio daily utilizing a Value-at-Risk (VAR) model, which monitors its risk in comparison to established thresholds. Please refer to the 2006 Form 10-K for further discussion of the VAR model. As of March 31, 2007, Avista Energy's estimated potential one-day unfavorable impact on gross margin as measured by VAR was $0.4 million, compared to $0.4 million as of December 31, 2006. The average daily VAR for the three months ended March 31, 2007 was $0.7 million. The high daily VAR was $1.1 million and the low daily VAR was $0.3 million during the three months ended March 31, 2007. Avista Energy was in compliance with its one-day VAR limits during the three months ended March 31, 2007. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted limits.

Environmental Issues and Other Contingencies

We are subject to environmental regulation by federal, state and local authorities. The generation, transmission, distribution, service and storage facilities in which we have an ownership interest were designed to comply with all applicable environmental laws.

We monitor legislative developments at both the state and national level with respect to environmental issues, particularly those related to the potential for further restrictions on the operation of our generating plants.

Current environmental laws and regulations have, and future modifications may have, the effect of:

- increasing the lead time for the construction of new generating plants,
- requiring modification of our existing generating plants,
- increasing the risk of delay on construction projects,
- reducing the amount of energy available from our generating plants, and
- restricting the types of generating plants that can be built.

As such, compliance with such environmental laws and regulations could result in increases to capital expenditures and operating expenses. However, we intend to seek recovery of incurred costs through the rate making process.

Long-term global climate changes, particularly with respect to the Pacific Northwest, could have a significant effect on our business. Changing temperatures and precipitation, including snowpack conditions, affect the availability and timing of hydroelectric generation capacity. Changing temperatures could also increase or decrease customer demand. Our operations could also be affected by any legislative or regulatory developments in response to global climate changes, including restrictions on the operation of our power generation resources.

We continue to monitor and evaluate the possible adoption of national, regional, or state greenhouse gas requirements. In particular, a greenhouse gas bill has been passed by the legislature in the state of Washington and bills have been introduced in the U. S. Senate and House of Representatives.

The greenhouse gas bill passed by the legislature in the state of Washington would place significant restrictions on greenhouse gas emissions from any new generation plants built in the state of Washington. Furthermore, utilities would be prevented from entering into contracts to purchase energy produced by plants in other states that do not meet the same restrictions. Currently, the only type of thermal generating plants that meet these restrictions are combined-cycle natural gas-fired generation turbines. This greenhouse gas bill sets goals to reduce emissions in the state of Washington to 1990 levels by 2020; to 25 percent below 1990 levels by 2035; and to 50 percent below 1990 levels by 2050.

Greenhouse gas requirements could result in significant costs for us to comply with restrictions on carbon dioxide or other greenhouse gas emissions. Such requirements could also preclude us from developing certain types of generating plants, including coal-fired plants.

Initiative Measure 937 (I-937) was passed into law through the General Election in Washington in November 2006. I-937 requires certain investor-owned, cooperative, and government-owned electric utilities (including Avista Corp.) to acquire new renewable energy resources and/or renewable energy credits in incremental amounts until those resources or credits equal 15 percent of the utility's total retail load in 2020. I-937 also requires these utilities to meet biennial energy conservation targets beginning in 2012. Failure to comply with renewable energy and conservation standards will result in penalties of at least $50 per MWh being assessed against a utility for each MWh it is deficient in meeting a standard. A utility would be deemed to comply with the renewable energy standard if it invests at least 4 percent of its total annual retail revenue requirement on the incremental costs of renewable resources and/or renewable credits. Our most recent Electric Integrated Resource Plan (IRP) includes the acquisition of additional renewable resources such that, if the IRP is implemented, we would be compliant with the requirement by 2020 assuming that such renewable resources were cost effective. The amount of renewable resources in our future IRPs could change if the cost effectiveness of those resources changes.

For other environmental issues and other contingencies see "Note 12 of the Notes to Consolidated Financial Statements."

Item 3. Quantitative and Qualitative Disclosures About Market Risk

See "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations: – Business Risk and – Risk Management," "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations – Energy Marketing and Resource Management – Energy trading activities and positions," and "Note 6 of the Notes to Consolidated Financial Statements."

Item 4. Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended) to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the

Company's management, including its principal executive and principal financial officers as appropriate to allow timely decisions regarding required disclosure. Under the supervision and with the participation of the Company's management, including the Company's principal executive officer and principal financial officer, the Company has evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon the Company's evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures are effective at a reasonable assurance level as of March 31, 2007.

There have been no changes in the Company's internal control over financial reporting that occurred during the first quarter of 2007 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

See "Note 12 of the Notes to Consolidated Financial Statements" which is incorporated by reference.

Item 1A. Risk Factors

Please refer to the 2006 Form 10-K for disclosure of risk factors that could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results or outcomes to differ materially from those discussed in our reports filed with the Securities and Exchange Commission (including this Quarterly Report on Form 10-Q), and elsewhere. These risk factors have not materially changed from the disclosures provided in the 2006 Form 10-K.

Our risk factors related to Avista Energy's operations are expected to change with the closing of the sale of contracts and ongoing operations to Coral Energy as many of the risk factors specifically related to Avista Energy would be eliminated.

In addition to these risk factors, please also see "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—Forward-Looking Statements" for additional factors which could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

Item 6. Exhibits

10.1	Purchase and Sale Agreement by and among Avista Energy, Inc. and Avista Energy Canada, Ltd. as Sellers and Coral Energy Holding, L.P., Coral Energy Resources, L.P., Coral Power, L.L.C. and Coral Energy Canada Inc. as Purchasers dated as of April 16, 2007*
12	Computation of ratio of earnings to fixed charges and preferred dividend requirements*
15	Letter Re: Unaudited Interim Financial Information*
31.1	Certification of Chief Executive Officer*
31.2	Certification of Chief Financial Officer*
32	Certification of Corporate Officers (Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)**

* Filed herewith.
** Furnished herewith.

AVISTA CORPORATION

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

AVISTA CORPORATION
(Registrant)

Date: May 4, 2007

/s/ Malyn K. Malquist
Malyn K. Malquist
Executive Vice President and Chief Financial Officer
(Principal Accounting and Financial Officer)

Exhibit 10.1

PURCHASE AND SALE AGREEMENT

by and among

Avista Energy, Inc. and Avista Energy Canada, Ltd.

as Sellers

and

Coral Energy Holding, L.P., Coral Energy Resources, L.P., Coral Power, L.L.C. and Coral Energy Canada Inc.

as Purchasers

Dated as of April 16, 2007

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Exhibits

PURCHASE AND SALE AGREEMENT

This Purchase and Sale Agreement ("**Agreement**"), dated as of April 16, 2007 is made and entered into by and among **Avista Energy, Inc.** , a Washington corporation (" **Avista Energy** ") and Avista Energy Canada, Ltd. an amalgamated corporation of the Province of Alberta, Canada (" **Avista Canada** ") (collectively, " **Sellers** "), and **Coral Energy Holding, L.P.** , a Delaware limited partnership (" **Coral Holding** "), **Coral Energy Resources, L.P.** , a Delaware limited partnership (" **Coral Resources** "), **Coral Power, L.L.C.** , a Delaware limited liability company (" **Coral Power** ") and **Coral Energy Canada Inc** ., a corporation organized under the laws of the Province of Alberta, Canada (" **Coral Canada** ") (collectively, " **Purchasers** ").

RECITALS

WHEREAS, Sellers desire to sell and assign to Purchasers and Purchasers desire to buy and accept from Sellers substantially all of the active, operating assets owned and used by Sellers in the operation of the business.

NOW THEREFORE, in consideration of the premises and the mutual covenants and agreements set forth in this Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

AGREEMENT

1. **Agreement and Interpretation.**

1.1. **Definitions.**

Capitalized terms used in this Agreement have the meanings given to them in **Appendix A** to this Agreement.

1.2. **Construction.**

1.2.1. All article, section, subsection, schedule, appendix and exhibit references used in this Agreement are to articles, sections, subsections, schedules, appendices and exhibits to this Agreement unless otherwise specified. The appendices, exhibits and schedules attached to this Agreement constitute a part of this Agreement and are incorporated herein and made a part hereof for all purposes.

1.2.2. If a term is defined as one part of speech (such as a noun), it shall have a corresponding meaning when used as another part of speech (such as a verb). Unless the context of this Agreement clearly requires otherwise, the singular shall include the plural and the plural shall include the singular wherever and as often as may be appropriate. Words importing the masculine gender shall include the feminine and neutral genders and *vice versa* . The words "includes" or "including" shall mean "including without limitation." The rule *ejusdem generis* may not be invoked to restrict or limit the scope of the general term or phrase followed or preceded by an enumeration of particular examples. The words "hereof," "hereby," "herein," "hereunder" and similar terms in this Agreement shall refer to this Agreement as a whole and not any particular section or article in which such words appear, unless the context of this Agreement clearly requires otherwise. Any reference to a Law shall include any amendment thereof or any successor thereto and any rules and regulations promulgated thereunder, as the same may be in effect from time to time. Currency amounts referenced herein, unless otherwise specified, are in U.S. Dollars.

1.2.3. Time is of the essence in this Agreement. Whenever this Agreement refers to a number of days, such number shall refer to calendar days unless Business Days are specified. Whenever any action must be taken hereunder on or by a day that is not a Business Day, then such action may be validly taken on or by the next day that is a Business Day. Any reference to time shall be deemed to be the local time in Spokane, Washington.

1.2.4. All accounting terms used herein and not expressly defined herein shall have the meanings given to them under GAAP.

1.2.5. Any amount owed by one Party to another Party hereunder that is not paid by the applicable due date shall bear interest at the Applicable Rate.

1.2.6. Each Party acknowledges that it and its attorneys have been given an equal opportunity to negotiate the terms and conditions of this Agreement and that any rule of construction to the effect that ambiguities are to be resolved against the drafting Party or any similar rule operating against the drafter of an agreement shall not be applicable to the construction or interpretation of this Agreement.

2. **Purchase and Sale Transaction.**

2.1. **Purchase and Sale.**

Subject to the terms and conditions set forth in this Agreement, the Parties agree that as of the Effective Time, Sellers shall sell, assign, transfer, convey, deliver and release to Purchasers free and clear of all Liens and liabilities (except for Permitted Liens and the Assumed Liabilities) and Purchasers shall purchase, accept and assume from Sellers, all of Sellers' right, title and interest in and to the Acquired Assets and the Assumed Liabilities. Each of the Parties understands and agrees that Purchasers are not acquiring or assuming and have no interest in or obligation with respect to the Excluded Assets and the Retained Liabilities.

2.2. **Purchase Price.**

2.2.1. Purchasers shall pay to Sellers, as consideration for the assignment to and assumption by Purchasers of the Acquired Assets and the Assumed Liabilities related thereto, the " **Purchase Price** ," which shall be calculated as follows:

(a) The Net Trade Book Value calculated as of the Effective Time in accordance with past practice; plus

(b) The net book value of all furniture, office equipment and select software, hardware, telemetry and other communications equipment (the " **Tangible Assets** ") being acquired as reflected on Sellers' balance sheet as of the Effective Time calculated in accordance with past practice; plus

(c) The Market Value of the Natural Gas Inventory owned by Sellers as of the Effective Time; minus

(d) Any adjustment calculated as set forth on Schedule 2.2.1(d).

2.2.2. Payment of Purchase Price

(a) At least ten (10) Business Days prior to the anticipated Closing Date, Sellers shall deliver to Purchasers the following:

(i) A statement setting forth in reasonable detail the "**Estimated Purchase Price,**" which shall be calculated as follows:

A. An amount equal to 90% of the Net Trade Book Value as calculated by Sellers as of the Estimate Date; plus

B. An amount equal to the net book value of the Tangible Assets as of the Estimate Date; plus

C. An amount equal to the Market Value of the Natural Gas Inventory owned by Sellers as of the Estimate Date.

(ii) Documentation supporting the calculation of the Estimated Purchase Price, including the Electronically Recorded Trade Book, a schedule listing the Manually Recorded Commodity Transactions, and a schedule setting forth the energy commodity assets and energy commodity liabilities included in Net Trade Book Value, in each case as of the Estimate Date.

(b) On the first Business Day following the Effective Time, Purchasers shall remit to Sellers via wire transfer the amount of the Estimated Purchase Price less any adjustment calculated as set forth on Schedule 2.2.1(d) and, subject to Section 2.7, any Canadian withholding tax, if applicable. In addition, within seven (7) Business Days following the Effective Time, the Parties will effect the payment, if any, described in Section 5.10.2.

(c) On the first Business Day following the Effective Time, Purchasers shall deliver the Canadian Withholding Tax Escrow Amount to the Canadian Withholding Tax Escrow Agent as provided in Section 2.7.

(d) Within ten (10) Business Days following the Effective Time, Sellers shall in good faith provide to Purchasers its calculation of the Purchase Price as of the Effective Time, together with any supporting documentation. Within ten (10) Business Days following receipt of this Purchase Price calculation and supporting materials, Purchasers shall notify Sellers in writing as to whether it accepts Sellers' calculation of the Purchase Price or provide Sellers with a detailed explanation as to why it is disputing Sellers' calculation of the Purchase Price. Failing delivery of such notice within such ten (10) Business Day period, Purchasers shall be deemed conclusively to have accepted Sellers' calculation of the Purchase Price.

(e) If Purchasers agree with Sellers' calculation of the Purchase Price and if the Purchase Price exceeds the Estimated Purchase Price (less any adjustment calculated as set forth on Schedule 2.2.1(d)), Purchasers shall remit such difference to Sellers within two (2) Business Days of receipt of Purchasers' acceptance of the Purchase Price calculation plus interest on such amount calculated at the Applicable Rate from the Closing Date until the date of payment. If the Estimated Purchase Price (less any adjustment calculated as set forth on Schedule 2.2.1(d)) exceeds the Purchase Price, then Sellers shall remit such difference to Purchasers within two (2) Business Days of receipt of Purchasers notification of acceptance of the Purchase Price calculation plus interest on such amount calculated at the Applicable Rate from the Closing Date until the date of payment.

(f) If Purchasers disagree with Sellers' calculation of the Purchase Price as set forth in Section 2.2.2(d), the Parties will promptly enter into good faith discussions to resolve the differences. If such discussions have not resolved the dispute within thirty (30) days from the date on which the notice of the dispute was given by Purchasers to Sellers as provided in Section 2.2.2(d), the matter shall be submitted to the chief executive officers of each of the Parties for resolution. If such chief executive officers have not resolved the dispute within fifteen (15) days of the expiration of the prior thirty (30) day period, the Parties will submit the matter for a determination to Ernst & Young, LLP, and if Ernst & Young, LLP is unwilling or unable to perform, the dispute will be referred to KPMG LLP, and if KPMG LLP is unable or unwilling to perform, to such other firm of nationally recognized independent certified public accounts as may be acceptable to the Parties (the "**Arbitrator**"). The Parties shall promptly make available to the Arbitrator such information and persons as may be requested by the Arbitrator for purposes of making its determination and shall otherwise cooperate with the Arbitrator as fully as reasonably possible. The Arbitrator shall calculate the Purchase Price in the manner as set forth in Section 2.2 and base its decision on the historical method for calculating the Net Trade Book Value and the Commodity Valuation Methodology. The determination of the Arbitrator shall be binding upon the Parties, without the right to appeal or review. If the Purchase Price as determined by the Arbitrator exceeds the Estimated Purchase Price (less any adjustment calculated as set forth on Schedule 2.2.1(d)), Purchasers shall remit such difference to Sellers within two (2) Business Days of written receipt of the Arbitrator's decision plus interest on such amount calculated at the Applicable Rate from the Closing Date until the date of payment. If the Estimated Purchase Price (less any adjustment calculated as set forth on Schedule 2.2.1(d)) exceeds the Purchase Price as determined by the Arbitrator, then Sellers shall remit such difference to Purchasers within two (2) Business Days of written receipt of the Arbitrator's decision plus interest on such amount calculated at the Applicable Rate from the Closing Date until the date of payment. Sellers and Purchasers shall each pay one half of the fees and costs of the Arbitrator.

(g) Any remittances required under Sections 2.2.2(d)-(f) herein shall be increased or decreased, as the case may be, to properly reflect the amount of Canadian withholding tax required to be withheld after taking into consideration the amount of such tax withheld pursuant to Section 2.2.2(c) . To the extent that additional withholding tax is required, Purchasers shall withhold such additional amounts as required and remit such amounts in accordance with the provisions of Section 2.7 on the same day as any additional Purchase Price is remitted to Sellers.

2.3. **Assumption of Liabilities and Obligations.**

Immediately after the Effective Time, and subject to Section 2.6, Purchasers shall assume and undertake to pay, discharge and perform all of the Assumed Liabilities. Purchasers are not assuming and shall not be responsible for, either directly or indirectly, any Retained Liabilities, all of which shall remain the responsibility of Sellers.

2.4. **Interstate Pipeline and Storage Contracts.**

Section 3.8 of the Seller Disclosure Schedule includes those Assigned Contracts that are firm transportation contracts with pipelines located in the United States (" **U.S. Pipelines** ") subject to the jurisdiction of the FERC (" **Interstate Pipeline and Storage Contracts** "), the transfer of which to Purchasers will be subject to the FERC's capacity release rules and related interstate pipeline tariff provisions. Effective as of the Effective Time and subject to the terms of this Agreement as well as applicable rules and regulations and tariff provisions of the U.S. Pipelines, Sellers hereby agree to permanently release, and Purchasers hereby agree to assume, the Interstate Pipeline and Storage Contracts on a prearranged basis for their full remaining terms at maximum rate, except for Interstate Pipeline and Storage Contracts that are contracted at a discounted or negotiated rate. If required under any applicable Law or tariff, Sellers shall post for public bid any Interstate Pipeline and Storage Contracts that it holds that are contracted at a discounted rate at such discounted rate. At least one Purchaser agrees to bid on such contract at the discounted or negotiated rate. Sellers and Purchasers agree to comply with all applicable laws and all applicable provisions and procedures of the U.S. Pipelines' tariffs necessary to enable Purchasers to take direct, permanent assignment of the Interstate Pipeline and Storage Contracts. The applicable Purchaser agrees to promptly execute any revised or amended service agreements tendered to it by any of the U.S. Pipelines, each with a term beginning on the Effective Time and continuing through the remaining term of each respective Interstate Pipeline and Storage Contract. These revised or amended service agreements will be deemed null and void if this Agreement is terminated pursuant to Section 9 , and, if necessary, Purchasers will reassign and Sellers will accept reassignment of the Interstate Pipeline and Storage Contracts. For the avoidance of doubt, the Jackson Prairie Capacity Release Agreement shall not be considered an Interstate Pipeline and Storage Contract for purposes of this Section.

2.5. **Canadian Pipeline Agreements.**

Section 3.8 of the Seller Disclosure Schedule includes those Assigned Contracts that are firm transportation contracts with pipelines located in Canada (" **Canadian Pipelines** ") and subject to the jurisdiction of the National Energy Board ("**Canadian Pipeline Contracts**"), the assignment of which to Purchasers will be subject to the respective tariffs of the Canadian Pipelines and any applicable National Energy Board rules and provincial regulations. Effective as of the Effective Time and subject to the terms of this Agreement, as well as all applicable rules, regulations and tariff provisions of the Canadian Pipelines, Sellers hereby agree to permanently assign, and Purchasers hereby agree to assume, the Canadian Pipeline Contracts, each for its full remaining term and at the maximum rate, except for Canadian Pipeline Contracts that are contracted at a discounted or negotiated rate, which Purchasers agree to assume at the applicable discounted or negotiated rate. Sellers and Purchasers agree to comply with all applicable laws and all applicable provisions and procedures of the Canadian Pipelines' tariffs necessary to enable Purchasers to take direct, permanent assignment of the Canadian Pipeline Contracts. The applicable Purchaser agrees to promptly execute any revised or amended service agreements tendered to it by any of the Canadian Pipelines, each with a term beginning on the Effective Time and continuing through the remaining term of each respective Canadian Pipeline Contract. These revised or amended service agreements will be deemed null and void if this Agreement is terminated pursuant to Section 9, and, if necessary, Purchasers will reassign and Sellers will accept reassignment of the Canadian Pipeline Contracts.

2.6. **Deemed Assignment of Contracts.**

To the extent that the assignment hereunder of any of the Assigned Contracts identified in Section 3.8 of the Seller Disclosure Schedule, other than those Assigned Contracts identified on Schedules 2.2.1(d) and 2.10.16, shall require the consent of any other party (or in the event that any of the same shall be non-assignable), neither this Agreement nor any actions taken hereunder shall constitute an assignment or an agreement to assign if such assignment or attempted assignment would constitute a breach thereof or result in a loss or diminution thereof. Sellers shall cooperate with Purchasers to establish a reasonable arrangement designed to provide Purchasers with the benefits and burdens of any such Assigned Contracts, including to the extent not constituting an assignment or attempted assignment that would violate the foregoing sentence, (a) appointing Purchasers to act as Sellers' agent to perform all of Sellers' obligations under such Assigned Contracts and to collect and promptly remit to Purchasers all compensation received by Sellers pursuant to such Assigned Contracts, (b) Purchasers agreeing to advance on behalf of Sellers, but at the expense of and for the account of Purchasers, amounts due and owing under such Assigned Contracts for obligations pertaining to periods following the Effective Time (including the provision of credit support as may be required by a Counterparty to such Assigned Contracts) and (c) to enforce, at the written request of, at the expense of and for the account and benefit of Purchasers, any and all rights of Sellers against any other person arising out of the breach or cancellation of such Assigned Contracts by such other person or otherwise (any and all of which arrangement shall constitute, as between the Parties, a deemed assignment or transfer); provided that from and after the Effective Time, Sellers shall have no liability to Purchasers in the event that any Assigned Contract requiring consent to assignment hereunder (or which by its terms is non-assignable) is terminated. Purchasers shall reimburse Sellers' for their reasonable costs and expenses (other than Taxes) associated with such alternative arrangements.

2.7. **Canadian Escrow Agent and Canadian Withholding Tax Certificates.**

2.7.1. Delivery of Canadian Withholding Tax Certificate. Subject to this Section 2.7, Avista Energy will deliver to the CRA, with a copy to Purchasers, an application for a Canadian Withholding Tax Certificate in respect of the Purchased Taxable Canadian Property and will take all reasonable steps to obtain and deliver a Canadian Withholding Tax Certificate to Purchasers on or before the Closing Date.

2.7.2. Canadian Withholding. If a Canadian Withholding Tax Certificate specifying a Canadian Withholding Tax Certificate Limit in an amount that is not less than the Taxable Canadian Property Purchase Price is not delivered to Purchasers at or before Closing, Purchasers will withhold from the Purchase Price otherwise payable at Closing the Canadian Withholding Tax Escrow Amount, which amount shall be distributed to the Canadian Withholding Tax Escrow Agent in accordance with the following provisions of this Section 2.7.

2.7.3. Canadian Withholding Tax Payments to CRA. If an amount is withheld under Section 2.7.2 and Avista Energy has received confirmation from CRA that CRA will issue a Canadian Withholding Tax Certificate to Avista Energy if an amount not exceeding the Canadian Withholding Tax Escrow Amount is received by the Receiver General of Canada before the Canadian Withholding Tax Remittance Date, which confirmation has been communicated to Purchasers and is, in form and substance, acceptable to Purchasers, acting reasonably, Purchasers shall notify the Canadian Withholding Tax Escrow Agent of that confirmation, and the Canadian Withholding Tax Escrow Agent will then pay that amount out of the Canadian Withholding Tax Escrow Amount to the Receiver General of Canada solely for purposes of obtaining the Canadian Withholding Tax Certificate and subject to the condition that any part of that amount not so applied and not returned by the Receiver General of Canada to the Canadian Withholding Tax Escrow Agent shall be applied to Purchasers' remittance obligation under subsection 116(5) or (5.3), as applicable of the Canada Tax Act. Purchasers, Avista Energy and the Canadian Withholding Tax Escrow Agent shall cooperate to make reasonable efforts to effect an arrangement with CRA to make the payment described in this Section 2.7.3 and the Canadian Withholding Tax Certificate issuance to occur on a simultaneous basis.

2.7.4. Payments to Sellers. If an amount is withheld under Section 2.7.2 and, before the Canadian Withholding Tax Remittance Date, the Canadian Withholding Tax Escrow Agent receives a Canadian Withholding Tax Certificate in respect of the Purchased Taxable Canadian Property, the Canadian Withholding Tax Escrow Agent will promptly pay to Sellers: (i) the Canadian Withholding Tax Escrow Amount less any part thereof previously paid to the Receiver General of Canada pursuant to Section 2.7.3 if the Canadian Withholding Tax Certificate is issued pursuant to subsection 116(4) of the Canada Tax Act; or (ii) where Section 2.7.4(i) does not apply, the Canadian Withholding Tax Escrow Amount less any part thereof previously paid to the Receiver General of Canada pursuant to Section 2.7.3 and less the product of (A) the amount by which the Taxable Canadian Property Purchase Price exceeds the amount specified in that Canadian Withholding Tax Certificate as the Canadian Withholding Tax Certificate Limit or proceeds of disposition, multiplied by (B) the percentage specified in subsection 116(5) of the Canada Tax Act, if the Canadian Withholding Tax Certificate is issued pursuant to subsection 116(2) of the Canada Tax Act or the percentage specified in subsection 116(5.3) of the Canada Tax Act if the Canadian Withholding Tax Certificate is issued pursuant to subsection 116(5.2) of the Canada Tax Act.

2.7.5. Remittances. If Purchasers have withheld the Canadian Withholding Tax Escrow Amount pursuant to Section 2.7.2 and Sellers do not deliver to Purchasers and the Canadian Withholding Tax Escrow Agent, before the Canadian Withholding Tax Remittance Date, a Canadian Withholding Tax Certificate under subsection 116(2), subsection 116(4), or subsection 116(5.2), as applicable, of the Canada Tax Act specifying a Canadian Withholding Tax Certificate Limit or proceeds of disposition equal to or greater than the Taxable Canadian Property Purchase Price, the Canadian Withholding Tax Escrow Agent will remit to the Receiver General of Canada, on the Canadian Withholding Tax Remittance Date, the Canadian Withholding Tax Amount (less any part thereof previously paid to the Receiver General of Canada on account of such amount pursuant to Section 2.7.3) and the amount so remitted together with any amounts paid pursuant to Section 2.7.3 shall be credited to Purchasers as a Payment on account of the Purchase Price.

2.7.6. Interest. Concurrently with the payments pursuant to Sections 2.7.4 or 2.7.5, if applicable, the Canadian Withholding Tax Escrow Agent will pay to Sellers the interest earned on the Canadian Withholding Tax Escrow Amount while on deposit with the Canadian Withholding Tax Escrow Agent to the date of that payment (less any Tax required to be withheld and remitted).

2.7.7. Confirmations. The Canadian Withholding Tax Escrow Agent will provide Sellers with proof that the Canadian Withholding Tax Escrow Amount and the interest earned thereon while held by the Canadian Withholding Tax Escrow Agent have been disbursed by the Canadian Withholding Tax Escrow Agent in accordance with the provisions of this Section 2.7 .

2.7.8. Closing Adjustment. If the Taxable Canadian Property Purchase Price is adjusted pursuant to Section 2.2.2(g), and Purchasers are required to pay to Sellers an additional amount pursuant to Section 2.2.2(g) , the foregoing provisions of this Section 2.7 shall apply to that additional amount and in those circumstances and for the purpose of this Agreement, the term "Canadian Withholding Tax Escrow Amount" shall include the applicable withholding rate for the Purchased Taxable Canadian Property times that additional amount, and the term "Canadian Withholding Tax Remittance Date" for such additional amount shall mean the 27th day following the end of the calendar month in which Purchasers are required to pay the additional amount pursuant to Section 2.2.2(g) .

2.8. **Allocation of Purchase Price.**

2.8.1. **Allocation of Purchase Price for Tax Purposes.**

Within the later of thirty (30) days following the Closing Date or ten (10) days following the determination of a final Purchase Price, the Parties shall use their commercially reasonable efforts to agree in writing as to the allocation of the Purchase Price among the Acquired Assets. The Parties shall file all tax returns, including IRS Form 8594, in accordance with any such agreed allocation, and shall use their reasonable commercial efforts to sustain any such agreed allocation in any subsequent Tax audit or dispute.

2.8.2. **Allocation in Event of Dispute.**

In the event that the parties are unable to agree upon the allocations provided for under Section 2.8.1, such allocations shall be determined by the Arbitrator, whose determination shall be binding on the parties. Sellers and Purchasers shall each pay one half of the fees and costs of the Arbitrator.

2.9. **Closing.**

The closing of the transactions contemplated by this Agreement shall take place on the Closing Date at the offices of Heller Ehrman LLP in Seattle, Washington or San Diego, California or on such other date and at such other location as the Parties may mutually agree.

2.10. **Deliveries by Sellers.**

On or before the Closing Date and as a condition to closing, Sellers shall deliver to Purchasers the following certificates, instruments and documents, in form and substance reasonably acceptable to Purchasers:

2.10.1. a certificate of an officer of each Seller, in form and substance satisfactory to Purchasers, dated as of the Closing Date, setting forth and attesting to (i) such Seller's authority to enter into this Agreement and the Transaction Agreements and to consummate the transactions contemplated hereby and thereby, and (ii) the incumbency and signature of the officers of such Seller executing this Agreement and the Transaction Agreements and any other documents necessary to consummate the transactions contemplated hereby and thereby;

2.10.2. a certificate, dated as of the Closing Date, executed by the president or a vice-president of each Seller to the effect that each of the conditions specified in Section 7 have been satisfied in all respects;

2.10.3. a copy of the order of the FERC issuing the Jackson Prairie Limited Jurisdiction Certificate;

2.10.4. a copy of the FERC Order Authorizing the Disposition of Jurisdictional Facilities Under Section 203 of the FPA;

2.10.5. an executed copy of the Jackson Prairie Capacity Release Agreement pursuant to which Coral Resources shall be entitled to use not less than 2,976,252 Dths of Jackson Prairie expansion capacity and 104,000 Dths per day of deliverability;

2.10.6. an executed copy of the Lancaster Energy Conversion Agreement;

2.10.7. an executed copy of the Indemnification Agreement;

2.10.8. an executed copy of the Security Agreement and such other documentation as may be required to perfect Purchasers' first priority lien in the collateral as defined therein;

2.10.9. an executed copy of the Escrow Agreement;

2.10.10. an executed copy of the Canadian Withholding Tax Escrow Agreement;

2.10.11. an executed copy of the Guaranty from Avista Capital;

2.10.12. an executed copy of the Agency Agreement;

2.10.13. an executed copy of the NOVA/ANG Capacity Assignment;

2.10.14. an executed copy of the GTN Capacity Release Agreement;

2.10.15. an executed copy of the Transition Services Agreement;

2.10.16. an executed copy of the consents relating to the Assigned Contracts set forth on Schedule 2.10.16;

2.10.17. an executed copy of the consent described on Schedule 2.2.1(d) or, if such consent has not been obtained, written acknowledgement that such consent has not been obtained;

2.10.18. copies of the applications for the Canadian Withholding Tax Certificate pursuant to Section 2.7;

2.10.19. a certification of non-foreign status for Avista Energy, signed by the president or a vice-president of Avista Energy under penalty of perjury, pursuant to Treasury Regulations Section 1.1445-2 dated as of the Closing Date;

2.10.20. complete originals or, if the original is not available, copies, of the Assigned Contracts, with all amendments, transactions, confirmations and correspondence related thereto, shall be available for delivery at Sellers' office(s);

2.10.21. evidence in form and substance satisfactory to Purchasers that all Liens and encumbrances against the Acquired Assets, other than the Permitted Liens and the Assumed Liabilities, have been released or if such release has been delayed solely for administrative reasons, such Liens will be released within two (2) Business Days of the Closing Date;

2.10.22. evidence that Sellers have obtained all consents, authorizations and approvals of all Governmental Authorities and Persons described in Section 5.1.1; and

2.10.23. copies of any Assignments received as of the Closing Date.

2.11. **Deliveries by Purchasers.**

On or before the Closing Date and as a condition to closing, Purchasers shall deliver to Sellers the following certificates, instruments and documents, in form and substance reasonably acceptable to Sellers:

2.11.1. a certificate of an officer of each Purchaser, in form and substance satisfactory to Sellers, dated as of the Closing Date, setting forth and attesting to (i) such Purchaser's authority to enter into this Agreement and the Transaction Agreements and to consummate the transactions contemplated hereby and thereby, and (ii) the incumbency and signature of the officers of such Purchaser executing this Agreement and the Transaction Agreements and any other documents necessary to consummate the transactions contemplated hereby and thereby;

2.11.2. a certificate, dated as of the Closing Date, executed by the president or a vice-president of each Purchaser to the effect that each of the conditions specified in Section 8 have been satisfied in all respects;

2.11.3. an executed copy of the Jackson Prairie Capacity Release Agreement pursuant to which Coral Resources shall be entitled to use not less than 2,976,252 Dths of Jackson Prairie expansion capacity and 104,000 Dths per day of deliverability;

2.11.4. an executed copy of the Lancaster Energy Conversion Agreement;

2.11.5. an executed copy of the Indemnification Agreement;

2.11.6. an executed copy of the Security Agreement and such other documentation as may be required to perfect Purchasers' first priority lien in the collateral as defined therein;

2.11.7. an executed copy of the Escrow Agreement;

2.11.8. an executed copy of the Canadian Withholding Tax Escrow Agreement;

2.11.9. an executed copy of the Agency Agreement;

2.11.10. an executed copy of the NOVA/ANG Capacity Assignment;

2.11.11. an executed copy of the GTN Capacity Release Agreement; and

2.11.12. an executed copy of the Transition Services Agreement.

2.12. **Additional Obligations.**

Subject to the terms and conditions of this Agreement, Avista Energy shall temporarily assign to Coral Power and Coral Power shall accept, Avista Energy's rights, title, interest, and obligations in, to and under the BPA Transmission Agreement. Assignment of the BPA Transmission Agreement shall commence on the Effective Date or at such other date mutually acceptable to Avista Energy and Coral Power and terminate on December 31, 2009. Such assignment shall occur in accordance with the applicable procedures and requirements of the BPA on the date of assignment. During the term of such assignment, Coral Power shall accept and comply with all obligations arising from or under the BPA Tariff associated with the assignment, including the payment of any and all costs related to use of the assigned transmission rights during the term of such temporary assignment. With respect to such assignment, Avista Energy and Coral Power agree in good faith to address any issues related to billing and payment in order to comply with requirements imposed by BPA, as such requirements may be revised from time to time. Provided further and subject to the terms of the Indemnification Agreement, that during the term of such assignment, Purchasers agree to indemnify Avista Energy and hold it harmless from all losses, liabilities or claims including reasonable attorneys' fees and costs of court, from any and all persons, arising from or out of claims of title, personal injury (including death) or property damage from said BPA Transmission Agreement that may have occurred during the term of such temporary assignment. Upon the conclusion of the term of the temporary assignment referred to in this Section 2.12, all rights, title, interest and obligations in, to and under the BPA Transmission Agreement shall revert back to Avista Energy and subject to the terms of the Indemnification Agreement, Avista Energy shall indemnify Purchasers and hold them harmless from all losses, liabilities or claims including reasonable attorneys' fees and costs of court, from any and all persons, arising from or out of claims of title, personal injury (including death) or property damage from said BPA Transmission Agreement that may have occurred during any period of time other than the during the term of the temporary assignment.

2.13. **Further Assurances.**

Subject to the terms and conditions of this Agreement, at any time, or from time to time after the Effective Time, as and when requested by any Party, the other Parties shall promptly execute and deliver, or cause to be executed and delivered, all such documents, instruments and certificates and shall take, or cause to be taken all such further or other actions as are reasonably requested as necessary to evidence and effectuate the transactions contemplated by this Agreement and the Transaction Agreements, in each case at the sole cost and expense of the requesting Party unless the requesting Party is entitled to indemnification therefore under the Indemnification Agreement.

3. **Representations and Warranties of Sellers.**

Sellers hereby, jointly and severally, represent and warrant to Purchasers that the statements contained in this Section 3 are correct and complete as of the date of this Agreement and as of the Effective Time, except as noted herein or as set forth in the disclosure schedule relating to the specified subsection (including by cross-reference contained therein), attached hereto as **Appendix B** (the " **Seller Disclosure Schedule** "). The Seller Disclosure Schedule will be arranged in paragraphs corresponding to the lettered and numbered paragraphs contained in this Section 3 and the other relevant sections of this Agreement.

3.1. **Organization, Standing and Power.**

Avista Energy is a corporation duly organized and validly existing under the Laws of Washington. Avista Canada is an amalgamated corporation duly organized, validly existing and in good standing under the Laws of the Province of Alberta, Canada. Each Seller has all requisite organizational power and authority to enter into this Agreement, to perform its obligations hereunder and to consummate the transactions contemplated hereby. Each Seller is duly qualified or licensed to do business in each other jurisdiction where the actions required to be performed by it hereunder make such qualification or licensing necessary, except in those jurisdictions where the failure to be so qualified or licensed would not reasonably be expected to result in a material adverse effect on such Seller's ability to perform its obligations hereunder.

3.2. **Authority.**

The execution and delivery by each Seller of this Agreement, and the performance by each Seller of its obligations hereunder, have been duly and validly authorized by all necessary action on the part of each Seller and its shareholder(s), as applicable. This Agreement has been duly and validly executed and delivered by each Seller and constitutes the legal, valid and binding obligation of each Seller enforceable against each Seller in accordance with its terms, except as the same may be limited by bankruptcy, insolvency, reorganization, arrangement, moratorium or other similar Laws relating to or affecting the rights of creditors generally, or by general equitable principles.

3.3. **No Conflicts; Consents and Approvals.**

Assuming the filings, approvals, consents, authorizations and notices set forth in Section 3.3 of the Seller Disclosure Schedule or any subpart thereof have been made, obtained or given, the execution and delivery by each Seller of this Agreement, the performance by each Seller of its obligations hereunder, and the consummation of the transactions contemplated hereby will not:

3.3.1. conflict with or result in a violation or breach of any of the terms, conditions or provisions of its Charter Documents;

3.3.2. conflict with, result in a default or violation or breach of any term or provision of any contract other than an Assigned Contract, which is not, individually or in the aggregate, material;

3.3.3. result in the creation of a Lien, other than Permitted Liens, on any of the Acquired Assets;

3.3.4. conflict with, or result in a violation or breach of, any material term or provision of any Law or writ, judgment, order or decree applicable to such Seller or any of its assets; or

3.3.5. require the consent or approval of any Governmental Authority under any applicable Law other than such consents or approvals described in _ Section 5.1.1 .

3.4. **Legal Proceedings.**

No Seller has received written notice of any Claim and, to Sellers' Knowledge, none is threatened against any Seller that (i) seeks to restrain, enjoin or otherwise prohibit or make illegal any of the transactions contemplated by this Agreement or any of the Transaction Agreements or (ii) relates to or arises out of any of the Assigned Contracts. No Seller has received actual notice of the assertion by any Person of a Claim that the consummation of the transactions contemplated hereby would violate any material contract to which any Seller is a party and as to which the claimant could reasonably be expected to assert a Claim against any Purchaser or such Seller with respect to their rights under the Assigned Contracts and, to Sellers' Knowledge, no such Claim has been threatened.

3.5. **Compliance with Laws and Orders.**

No Seller is in violation of or in default under any Law or order applicable to such Seller or its assets the effect of which, individually or in the aggregate, could reasonably be expected to hinder or prevent such Seller from performing its obligations hereunder.

3.6. **Brokers.**

No Seller has any liability or obligation to pay fees or commissions to any broker, finder or agent with respect to the transactions contemplated by this Agreement for which Purchasers could become liable or obligated.

3.7. **Title.**

Sellers own and have good and marketable title to the Acquired Assets free and clear of all Liens other than Permitted Liens, Assumed Liabilities and Liens in connection with (i) agreements pursuant to which a Counterparty has imposed a security interest on a Seller's cash margin or marketable securities posted with such Counterparty; (ii) purchase money liens and liens securing rental payments under capital lease arrangements or (iii) the Credit Agreement.

3.8. **Assigned Contracts.**

Section 3.8 of the Seller Disclosure Schedule contains a complete and accurate listing of the Assigned Contracts (excluding confirmation of transactions conducted pursuant to such Assigned Contracts in the ordinary course of business), including all amendments, modifications or waivers thereto, and Sellers have provided to Purchasers true, correct and complete copies of all such Assigned Contracts. Except for any agreement expressly identified as an Excluded Asset, the Assigned Contracts, taken as a whole, constitute substantially all of the operating assets of the Sellers.

3.9. **Enforceability of Assigned Contracts.**

Each of the Assigned Contracts constitutes the legal, valid and binding obligation of each Seller that is a party thereto enforceable against it in accordance with its terms and, to Sellers' Knowledge, constitutes the legal, valid and binding obligation of each other party thereto, except in each case as the same may be limited by bankruptcy, insolvency, reorganization, arrangement, moratorium or other similar Laws relating to or affecting the rights of creditors generally, or by general equitable principles. No Seller has assigned any of its right, title or interest under any Assigned Contract to any other Person except in connection with (i) Permitted Liens, (ii) agreements pursuant to which a Counterparty has imposed a security interest on a Seller's cash margin or marketable securities posted with such Counterparty; (iii) purchase money liens and liens securing rental payments under capital lease arrangements and (iv) the Credit Agreement.

3.10. **Defaults.**

No Seller is, and to Sellers' Knowledge, no other party is in material breach of or default under any Assigned Contract and no Seller has sent nor received any written notice or, to Sellers' Knowledge, any oral notice, of termination, cancellation, breach or default with respect to any of the Assigned Contracts. To Sellers' Knowledge (i) there are no material disputes between any Seller and any Counterparty under any of the Assigned Contracts and (ii) none of the Assigned Contracts is subject to a declared, continuing event of force majeure.

3.11. **Canadian Agreements.**

To Sellers' Knowledge, Section 3.8 of the Seller Disclosure Schedule identifies any of the Assigned Contracts that, as of April 1, 2007 requires the physical delivery of any Commodity in Canada pursuant to any open transaction or arrangement.

3.12. **Bankruptcy.**

There are no bankruptcy, reorganization or receivership proceedings pending, being contemplated by or, to Sellers' Knowledge, threatened against any Seller. To Sellers' Knowledge, there are no bankruptcy, reorganization or receivership proceedings pending, being contemplated by or threatened against any Counterparty.

3.13. **Claims.**

As of the date of this Agreement:

(a) No Seller has received any written or oral Claim that seeks damages or other monetary relief in connection with any of the Assigned Contracts;

(b) No Seller has received any written or oral Claims that any of the Assigned Contracts are illegal, ineffective or inconsistent with or in violation of any Laws;

(c) No Seller has received any written or oral Claim seeking to modify any term or condition of any of the Assigned Contracts; and

(d) No Seller has received any actual notice of any type or description or in connection with any pending or threatened civil or enforcement Claim by any Governmental Authority against any Seller or any current or former employee, officer, director or agent of any Seller that contends, directly or indirectly, that any of the Assigned Contracts is inconsistent with or in violation of any Laws.

3.14. **Tax Representations.**

All returns, reports, or statements (including any information returns) any Governmental Authority requires to be filed by any Seller for purposes of any Tax (" **Returns** ") for which any Seller is liable have been duly and timely filed with the appropriate Governmental Authority having jurisdiction with respect to any Tax (" **Taxing Authority** ") and all such Returns are correct and complete. Each Tax shown to be payable on each such Return has been paid. Each Tax payable by any Seller by assessment has been timely paid in the amount assessed. No Seller is, or has ever been, liable for any Tax payable by reason of the income or property of a Person other than such Seller. Each Seller has timely filed true, correct and complete declarations of estimated Tax in each jurisdiction in which any such declaration is required to be filed by it. No Liens for Taxes exist upon any of the Acquired Assets except Liens for Taxes that are not yet due. No Claim with respect to any Tax for which any Seller is asserted to be liable is pending or, to Sellers' Knowledge, threatened and no basis that any Seller believes to be valid exists on which any Claim for any such Tax can be asserted against any Seller or any of the Acquired Assets. There are no requests for rulings or determinations in respect of any Taxes pending between a Seller and any Taxing Authority. No currently effective extension of any period during which any Tax may be assessed or collected and for which any Seller is or may be liable has been granted to any Taxing Authority. All amounts required to be withheld by any Seller and paid to governmental agencies for income, social security, unemployment insurance, sales, excise, use, value added and other Taxes have been collected or withheld and paid to the proper Taxing Authority. Each Seller has made all deposits required by Law to be made with respect to employees' withholding and other employment Taxes.

3.15. **Canadian Tax Representation.**

Avista Canada is duly registered under Part IX of the *Excise Tax Act* (Canada) with respect to the goods and services tax and harmonized sales tax and its registration number is 87626 4367 RT0001.

3.16. **Credit Support; Pre-Paid Deposits.**

3.16.1. With respect to guaranties, letters of credit, comfort letters, surety bonds, cash and other credit support in favor of any Counterparty provided by or on behalf of any Seller or its Affiliates in support of the obligations of such Seller or Affiliate (together, the " **Credit Support** "), Section 3.16.1 of the Seller Disclosure Schedule contains a complete and accurate list and summary description of all Credit Support as of March 31, 2007. Sellers have not defaulted or otherwise created a circumstance that triggers the right of any party to make a Claim under the Credit Support and there are no pending disputes with respect to any Credit Support.

3.16.2. With respect to pre-paid obligations, pre-paid cash deposits or deposits of marketable securities in favor of any Counterparty provided by a Seller or its Affiliates in support of the obligations of such Seller (together, the " **Pre-Paid Deposits** "), Section 3.16.2 of the Seller Disclosure Schedule contains a complete and accurate list and summary description of all Pre-Paid Deposits as of March 31, 2007. Sellers have not defaulted or otherwise created a circumstance that triggers the right of any party to make a Claim against or otherwise seize all or any portion of the Pre-Paid Deposits and there are no pending disputes with respect to any Pre-Paid Deposits.

3.16.3. With respect to guaranties, letters of credit, comfort letters, surety bonds, cash and other credit support in favor of a Seller provided by or on behalf of any of any Counterparty or its affiliates in support of the obligations of such Counterparties (together, the " **Counterparty Credit Support** "), Section 3.16.3 of the Seller Disclosure Schedule contains a complete and accurate list and summary description of all Counterparty Credit Support as of March 31, 2007. No counterparty is in default or has otherwise created a circumstance that triggers the right of a Seller to make a Claim under the Counterparty Credit Support and there are no pending disputes with respect to any Counterparty Credit Support.

3.16.4. With respect to pre-paid obligations, pre-paid cash deposits or deposits of marketable securities on behalf of the Counterparties deposited with Sellers in support of the obligations of the Counterparties under the Assigned Contracts (together, the " **Counterparty Pre-Paid Deposits** "), Section 3.16.4 of the Seller Disclosure Schedule contains a complete and accurate list and summary description of all Counterparty Pre-Paid Deposits as of March 31, 2007. Neither Seller has alleged or claimed a circumstance that triggers the right of any party to make a Claim against or otherwise seize all or any portion of the Counterparty Pre-Paid Deposits nor are there any pending disputes with respect to any Counterparty Pre-Paid Deposits.

3.17. **Environmental, Health and Safety.**

3.17.1. To Sellers' Knowledge, there is no reasonable basis for a Claim alleging injury arising out of or related to exposure to Commodities or any other substances (i) present at Sellers' facilities or (ii) owned, transported, leased or brokered by either of the Sellers.

3.17.2. Neither Seller has any liability and, to Sellers' Knowledge, neither of the Sellers (or their respective predecessors, if any) has handled or disposed of any substance, arranged for the disposal of any substance, exposed any employee or other individual to any substance or condition or owned or operated any property or facility in any manner that could form a reasonable basis for any present or future Claim against either of the Sellers giving rise to any liability for damage to any site, location, or body of water (surface or subsurface), for any illness of or personal injury to any employee or other individual, or for any reason under any Law. Neither of the Sellers has received any written communication, whether from a Governmental Authority, citizens group, employee or otherwise, that alleges a Seller is not in compliance with applicable environmental Laws.

3.18. **Commodities.**

3.18.1. Valuation Policy. Subject to amounts reserved for Commodities, the values at which all Commodities and Commodities Transactions are carried in Sellers' financial statements reflect the historical valuation policy of the Sellers and the Commodity Valuation Methodology. Sellers have title or rights to the Commodities, transmission and transportation agreements sufficient to operate the business in all material respects as it is presently conducted.

3.18.2. Trade Confirmations. Sellers' binding trade confirmations (whether written or oral) under each of the applicable Assigned Contracts are promptly and properly recorded in the Trade Book.

3.18.3. Risk and Credit Policy. Sellers have at all times during calendar year 2006 and through the date of this Agreement been in material compliance with the requirements of the Risk Policy and Credit Policy. Sellers have established reserves for the risks of their trading activities in accordance with GAAP and the amount of such reserves are reflected in the Net Trade Book Value as of the applicable date of calculation.

3.19. **Employees.**

3.19.1. Section 3.19.1 of the Seller Disclosure Schedule contains a complete and accurate list of the following information for each employee of Sellers, including each employee on leave of absence or layoff status: Employer; name; job title; part-time or full time status, current compensation paid or payable and any change in compensation since January 1, 2007; and service credited for purposes of vesting and eligibility to participate under any Employee Benefit Plan or any Employee Arrangement.

3.19.2. Sellers have paid in full to, or accrued on behalf of, all Persons performing services for Sellers as required by Law, all payments, wages, salaries, commissions, bonuses and other direct compensation for all services performed by such Persons, all vacation and other benefits that have accrued through the date of this Agreement for such Persons, and all amounts required to be reimbursed to such Persons for which appropriate reimbursement requests have been submitted or, to Sellers' Knowledge, are expected to be submitted.

3.19.3. There is no labor strike, dispute, slowdown, work stoppage or lockout actually pending or, to Sellers' Knowledge, threatened against or affecting Sellers.

3.19.4. Sellers are not parties to or bound by any collective bargaining or similar agreement with any labor organization, or work rules or practices agreed to with any labor organization or employee association applicable to employees of Sellers.

3.19.5. None of the employees of the Sellers are represented by any labor organization and, to Sellers' Knowledge, there are no current union organizing activities among the employees of Sellers, nor does any question concerning representation exist concerning such employees.

3.19.6. Avista Canada's workers' compensation account and source deductions are in good standing.

3.19.7. No charges of discrimination or other violation of equal employment laws with respect to or relating to Sellers are pending or, to Sellers' Knowledge, threatened before the Equal Employment Opportunity Commission or any other Governmental Authority. Sellers have not engaged in any unfair labor practice and no unfair labor practice complaint, grievance or arbitration proceeding is pending, or to Sellers' Knowledge, threatened.

3.19.8. To Sellers' Knowledge, no Governmental Authority responsible for the enforcement of labor or employment Laws intends to conduct an investigation or compliance audit with respect to or relating to Sellers labor or employment practices and no such investigation or compliance audit by any Governmental Authority is in progress.

3.19.9. There are no pending or, to Sellers' Knowledge, threatened wage and hour claims filed against Sellers with the United States Department of Labor or any other Governmental Authority.

3.19.10. There are no pending citations relating to Sellers filed by the Occupational Safety and Health Administration nor any other Governmental Authority and there are, to Sellers' Knowledge, no such threatened citations relating to Sellers.

3.20. **Employment Benefit Matters.**

3.20.1. Section 3.20.1 of the Seller Disclosure Schedule lists each Seller Employee Benefit Plan and each Seller Employee Arrangement, and such Schedule includes each Employee Benefit Plan or Employee Arrangement that is sponsored, maintained, or contributed to by an Affiliate of Sellers that covers or benefits employees of Sellers. Section 3.20.1 of the Seller Disclosure Schedule separately identifies each Seller Employee Benefit Plan and Seller Employee Arrangement that provides for any payment (whether of severance pay or otherwise) or acceleration, vesting or increase in benefits with respect to any employee, director or consultant of any of the Sellers upon the occurrence of a change in control or a severance or termination of service (either alone or upon the occurrence of any additional or subsequent events).

3.20.2. Sellers have delivered to Purchasers correct and complete copies of the plan documents and summary plan descriptions for each Seller Employee Benefit Plan and Seller Employee Arrangement that covers or benefits employees of the Sellers.

3.20.3. Except as set forth in Section 3.20.3 of the Seller Disclosure Schedule or in the next following sentence, as to any Seller Employee Pension Benefit Plan that is subject to Title IV of ERISA, there has been no event or condition which presents the risk of Employee Pension Benefit Plan termination, no accumulated funding deficiency, whether or not waived, within the meaning of Section 302 of ERISA or Section 412 of the Code has been incurred, no reportable event within the meaning of Section 4043 of ERISA (for which the disclosure requirements have not been waived) has occurred, no notice of intent to terminate such Employee Pension Benefit Plan has been given under Section 4041 of ERISA, no proceeding has been instituted under Section 4042 of ERISA to terminate such Employee Pension Benefit Plan, no liability to the PBGC has been incurred, and the assets of such Employee Pension Benefit Plan equal or exceed the actuarial present value of the benefit liabilities, within the meaning of Section 4041 of ERISA, under such Employee Pension Benefit Plan, based upon reasonable actuarial assumptions and the asset valuation principles established by the PBGC. As of December 31, 2006, the assets of the Retirement Plan for Employees of Avista Corporation do not equal or exceed the actuarial present value of the benefit liabilities, within the meaning of Section 4041 of ERISA, under such plan, based upon reasonable actuarial assumptions and the asset valuation principles established by the PBGC. As of December 31, 2006, the funded status of such plan on this basis expressed as a percentage has not materially decreased, and such benefit liabilities have not materially increased, since Sellers' disclosure regarding the plan on September 30, 2006.

3.20.4. With respect to any Employee Pension Benefit Plan which is not listed in Section 3.20.1 of the Seller Disclosure Schedule but which is sponsored, maintained or contributed to, or has been sponsored, maintained or contributed to within six years prior to the Closing Date, by any corporation, trade, business or entity under common control with the Sellers, within the meaning of Section 414(b), (c) or (m) of the Code or Section 4001 of ERISA (" **Commonly Controlled Entity** "), (A) no withdrawal liability, within the meaning of Section 4201 of ERISA, has been incurred, which withdrawal liability has not been satisfied, (B) no liability to the PBGC has been incurred by any Commonly Controlled Entity, which liability has not been satisfied, (C) no accumulated funding deficiency, whether or not waived, within the meaning of Section 302 of ERISA or Section 412 of the Code has been incurred, and (D) all contributions (including installments) to such plan required by Section 302 of ERISA and Section 412 of the Code have been timely made.

3.21. **No Material Change in Conduct.**

Since October 31, 2006, there has not been:

3.21.1. any change in the business, operations, properties or assets, liabilities, condition (financial or other) or results of operations of the Sellers that could reasonably be expected, either alone or together with all other such changes, to have a material adverse effect on the Acquired Assets;

3.21.2. any creation or other incurrence of any Lien (other than Permitted Liens or in connection with (i) agreements pursuant to which a Counterparty has imposed a security interest on a Seller's cash margin or marketable securities posted with such Counterparty; (ii) purchase money liens and liens securing rental payments under capital lease arrangements or (iii) the Credit Agreement) on any Acquired Asset;

3.21.3. any damage, destruction or other casualty loss (whether or not covered by insurance) affecting the Acquired Assets which, individually or in the aggregate, has had or could reasonably be expected to have a material adverse effect on the Acquired Assets;

3.21.4. any transaction or commitment made, or any contract or agreement entered into, by either of the Sellers (including the acquisition or disposition of any assets) or any relinquishment by any Seller of any contract or other right, in either case, material to Acquired Assets, other than transactions and commitments in the ordinary course of business consistent with past practices and those contemplated by this Agreement;

3.21.5. any change in any method of accounting or accounting practice, reserve methodology and associated assumptions by Sellers with respect to accounting for the Acquired Assets and Assumed Liabilities except for any such change adopted in accordance with GAAP;

3.21.6. any (i) employment, deferred compensation, severance, retirement or other similar agreement entered into with any employee of the Sellers (or any amendment to any such existing agreement), (ii) grant of any severance or termination pay to any such employee or (iii) change in compensation or other benefits payable to any such employee pursuant to any severance or retirement plans or policies; or

3.21.7. any labor dispute, other than routine individual grievances, or any activity or proceeding by a labor union or representative thereof to organize any employees of the Sellers, or any lockouts, strikes, slowdowns, work stoppages or threats thereof by or with respect to such employees.

3.22. **Investment Company Act.**

Neither Seller is an "investment company" within the meaning of the Investment Company Act of 1940 as amended.

3.23. **Investment Canada Act Compliance.**

For the purposes of Sections 14 and 14.1 of the Investment Canada Act, the value of the assets of the Canadian business or businesses to be acquired under this Agreement and the Transaction Agreements does not exceed Canadian $281 million.

4. **Representations and Warranties of Purchasers.**

Except as otherwise noted herein, Purchasers hereby, jointly and severally, represent and warrant to Sellers that the statements contained in this Section 4 are correct and complete as of the date of this Agreement and as of the Effective Time.

4.1. **Organization, Standing and Power.**

Coral Holding and Coral Resources are limited partnerships duly organized, validly existing and in good standing under the Laws of Delaware, Coral Power is a Delaware limited liability company, duly organized, validly existing and in good standing under the Laws of Delaware and Coral Canada is a corporation duly organized, validly existing and in good standing under the Laws of the Province of Alberta, Canada. Coral Holding and Coral Resources each have all requisite partnership power and authority to enter into this Agreement, to perform their obligations hereunder and to consummate the transactions contemplated hereby. Coral Power and Coral Canada each have all requisite organizational power and authority to enter into this Agreement, to perform their obligations hereunder and to consummate the transactions contemplated hereby. Each Purchaser is duly qualified or licensed to do business in each other jurisdiction where the actions required to be performed by it hereunder make such qualification or licensing necessary, except in those jurisdictions where the failure to be so qualified or licensed would not reasonably be expected to result in a material adverse effect on such Purchaser's ability to perform its obligations hereunder.

4.2. **Authority.**

The execution and delivery by each Purchaser of this Agreement and the performance by each Purchaser of its obligations hereunder have been duly and validly authorized by all necessary action on the part of each Purchaser and its shareholder(s) or partners, as applicable. This Agreement has been duly and validly executed and delivered by each Purchaser and constitutes the legal, valid and binding obligation of each Purchaser enforceable against each Purchaser in accordance with its terms except as the same may be limited by bankruptcy, insolvency, reorganization, arrangement, moratorium or other similar Laws relating to or affecting the rights of creditors generally.

4.3. **No Conflicts.**

The execution and delivery by each Purchaser of this Agreement, the performance by each Purchaser of its obligations hereunder and the consummation of the transactions contemplated hereby will not:

(a) conflict with or result in a violation or breach of any of the terms, conditions or provisions of its Charter Documents;

(b) conflict with, result in a default or violation or breach of any term or provision of any contract which is not, individually or in the aggregate, material;

(c) conflict with, or result in a violation or breach of, any material term or provision of any Law or writ, judgment, order or decree applicable to such Purchaser or any of its assets; or

(d) require the consent or approval of any Governmental Authority under any applicable Law other than such consents or approvals described in _ Section 5.1.1 .

4.4. **Legal Proceedings.**

No Purchaser has been served with notice of any Claim, and to Purchasers' Knowledge none is threatened against any Purchaser that seeks to restrain, enjoin or otherwise prohibit or make illegal any of the transactions contemplated by this Agreement or any of the Transaction Agreements.

4.5. **Compliance with Laws and Orders.**

No Purchaser is in violation of or in default under any Law or order applicable to such Purchaser or its assets the effect of which, individually or in the aggregate, could reasonably be expected to hinder or prevent such Purchaser from performing its obligations hereunder.

4.6. **No Brokers.**

No Purchaser has any liability or obligation to pay fees or commissions to any broker, finder or agent with respect to the transactions contemplated by this Agreement for which any Seller could become liable or obligated.

4.7. **Canadian Tax Representation.**

Coral Canada is duly registered under Part IX of the Excise Tax Act (Canada) with respect to the goods and services tax and harmonized sales tax and its registration number is: 89081 5491 RT0001.

5. **Pre-Closing Covenants**

The Parties hereby covenant and agree as follows for all periods prior to the Effective Time:

5.1. **Regulatory and other Authorizations**

5.1.1. Each of the Parties will give any notices to, make any filings with, and use its commercially reasonable efforts to obtain any authorizations, consents and approvals of Governmental Authorities and non-governmental third parties required or necessary to consummate the transactions contemplated herein or in the Transaction Agreements. Without limiting the generality of the foregoing:

(a) Each of the Parties will promptly file any Notification and Report Forms and related material that may be required with the Federal Trade Commission (" **FTC** ") and the Antitrust Division of the United States Department of Justice (" **DOJ** ") under the Hart-Scott-Rodino Act if any Party reasonably concludes such filing is necessary or advisable. In connection with any such filing, each Seller and each Purchaser shall furnish to the other such information and assistance as the other may reasonably request in connection with its preparation of any filing or submission necessary under the Hart-Scott-Rodino Act. The Parties shall keep each other apprised in a prompt manner of the status and inquiries or request for additional information from the FTC and the DOJ and shall comply promptly with any such inquiry request. The Parties shall use commercially reasonable efforts to obtain the early termination or expiration of any applicable waiting period required under the Hart-Scott-Rodino Act for the consummation of the transactions contemplated hereby. Purchasers shall pay one-half of any fee for any filing or submission necessary under the Hart-Scott-Rodino Act and Sellers shall pay the remaining one-half of any such fee.

(b) Sellers shall make an appropriate filing, pursuant to Section 203 of the FPA and any applicable state law or regulation with respect to the transactions contemplated by the

Transaction Agreements and to supply as promptly as practicable to the appropriate Governmental Authorities any additional information and documentary material that may be requested by a Governmental Authority. With respect to any such filings, including filings that will be submitted pursuant to the FPA, the Parties shall cooperate with respect to information necessary for such filings and shall give each other reasonable opportunity to comment on and revise drafts of any such filings before such filings are submitted to the appropriate Governmental Authority. Sellers shall refrain from taking any action that causes Sellers to be regulated by or under any Governmental Authority. Purchasers shall pay one-half of any fee for any filing or submission necessary under the FPA and Sellers shall pay one-half of any such fee. Except as expressly provided in this Agreement, each Party shall bear the costs associated with any other authorizations, notifications and consents for which it is responsible under this Agreement.

(c) Each of the Parties as appropriate will make any filing that is required or advisable in order to obtain prompt Competition Act Approval if any Party reasonably concludes such filing is necessary or advisable. In connection with any such filing, each of the Parties shall use commercially reasonable efforts to obtain Competition Act Approval as promptly as possible. Purchasers shall approve all filings and other written communications to the Commissioner, and Purchasers shall have the right to be present at any meetings (whether via telephone, in person or otherwise) involving Sellers and the Commissioner or other Competition Bureau personnel. Sellers shall furnish to Purchasers such information and assistance as Purchasers may reasonably request in connection with the preparation of any filing or submission necessary or advisable in connection with obtaining Competition Act Approval. Sellers shall keep Purchasers apprised in a prompt manner of any inquiries or request for additional information from the Commissioner and, subject to this Agreement, shall comply promptly with any such inquiry request. Purchasers shall keep Sellers reasonably informed as to the status of the proceedings related to obtaining the Competition Act Approval, including providing Sellers with copies of all written communications, in draft form, in order for Sellers to provide their reasonable comments. If any information to be shared between the Parties pursuant to this paragraph is deemed to be confidential information as determined reasonably by the disclosing Party, such information will be shared only with outside counsel of the other Parties. Purchasers shall pay one-half of any fee required under the Competition Act and Sellers shall pay the remaining one-half of such fee.

5.1.2. In order to consummate the transactions contemplated hereby, from the date hereof until the Effective Time, Sellers and Purchasers will work cooperatively and in good faith to take all commercially reasonable steps necessary or desirable, to obtain as promptly as practicable Assignments executed by each of the Counterparties to the Assigned Contracts listed in Section 3.8 of the Seller Disclosure Schedule.

5.2. **Certain Restrictions.**

Except as permitted or contemplated hereby or by the Transaction Agreements, from the date hereof until the Effective Time, each of the Sellers will conduct its business in the ordinary course of business consistent with past practice and use its commercially reasonable efforts to (i) preserve and maintain intact its business organizations and its business, (ii) keep available the services of its employees, (iii) continue in full force and effect without material modification the same or appropriate substitute policies or binders of insurance currently maintained in respect of its business and (iv) preserve its current relationships with Persons with which it has significant business relationships so long as such business relationships continue to satisfy the Risk Policy and the Credit Policy. Without limiting the foregoing, except as permitted or contemplated hereby or by the Transaction Agreements, no Seller will, without first obtaining the prior written consent of a Purchaser:

5.2.1. acquire, sell, lease, transfer, or otherwise dispose of, directly or indirectly, any Tangible Asset except in the ordinary course of business consistent with past practice;

5.2.2. agree or consent to any new agreement which would be accounted for as a Manually Recorded Commodity Transaction due to the inability of the Nucleus software system to accurately value such transaction, except for any item related to valuation adjustments required to comply with GAAP, Commodity Transactions that would not physically encumber any Fixed Transaction and any Commodity Transaction that is capable of being consummated in the brokered gas or power markets;

5.2.3. for the agreements that are or will be part of the Assigned Contracts, agree or consent to any new agreement or material modifications of an existing agreement *other than* : (i) agreements identified on Schedule 5.2.3(i) ; (ii) agreements having a term equal to or less than one year and involving aggregate monetary obligations equal to or less than $1,000,000 other than any Commodity Transaction entered into in the ordinary course of business; (iii) the entry into any agreement that provides a framework for a trading relationship between any Seller and a Counterparty, including agreements generally known in the Commodity Transactions Business as master agreements, enabling agreements, interchange agreements, netting agreements and Commodity Service Agreements and transactions under any such agreement in the ordinary course of business; (iv) the entry into new or renewal of transportation, transmission or storage agreements having a term expiring before October 31, 2007; (v) the termination of agreements identified on Schedule 5.2.3(v) .

5.2.4. mortgage or pledge an Acquired Asset, or create or suffer to exist any Lien, other than Permitted Liens and Liens in connection with (i) agreements pursuant to which a Counterparty has imposed a security interest on a Seller's cash margin or marketable securities posted with such Counterparty; (ii) purchase money liens and liens securing rental payments under capital lease arrangements or (iii) the Credit Agreement, thereupon;

5.2.5. terminate, amend, modify or change in any respect an Assigned Contract other than amendments, modifications or changes that will be effective only for periods prior to the Effective Time and will not have any effect on any Assigned Contract on or after the Effective Time and modifications permitted pursuant to Section 5.2.3 ;

5.2.6. unless mutually agreed otherwise or permitted pursuant to Section 5.2.3, grant any waiver of any term under or give any consent with respect to any Assigned Contract;

5.2.7. settle or resolve any pending or threatened Claim or investigation concerning the Assigned Contracts, unless such settlement or resolution creates no current or future obligation on any Purchaser, creates no encumbrance on the rights under an Assigned Contract to be acquired by Purchasers and does not alter the economic terms of any of the Assigned Contracts with respect to any period after the Effective Time;

5.2.8. adopt a plan of complete or partial liquidation or resolutions providing for or authorizing a liquidation, dissolution, purchase, consolidation, restructuring, recapitalization or other reorganization which would become effective prior to the Effective Date or could otherwise affect or impair the transactions contemplated hereunder or in the Transaction Agreement;

5.2.9. transfer the work location of employees, hire any new employees, or enter into, modify or amend any employee or director employment contracts, compensation arrangements or benefits unless required by applicable Law or as otherwise agreed by the Parties; or

5.2.10. commit to do any of the foregoing.

In the event that Sellers decide to enter into a new transportation, transmission or storage agreement having a term expiring after April 30, 2007 and on or before October 31, 2007, it shall first provide Purchasers an opportunity to provide such transportation, transmission or storage at a price or prices and on terms and conditions substantially the same as those that such Seller is able to obtain from a third party. If Purchasers do not elect to accept this opportunity within 48 hours of the time offered, then Sellers may enter into the agreement with the third party.

5.3. **Sellers' Operations.**

Except as permitted or contemplated by the Transaction Agreements, from the date hereof until the Effective Time, Sellers agree that they will:

5.3.1. Use commercially reasonable efforts to (i) preserve and maintain intact their business organizations and business, (ii) keep available to Sellers the services of their employees, (iii) preserve their current relationships with Persons with which they have significant business relationships so long as such business relationships continue to satisfy their Risk and Credit Policies, and (iv) maintain the services provided by their Affiliates on terms consistent with past practices.

5.3.2. For each month from the date of this Agreement through the Closing Date, Sellers shall, in good faith, obtain or prepare and send to Purchasers the financial records and reports as specified in Schedule 5.3.2. All valuation adjustments shall be made on the same basis and pursuant to the same principles, methodologies and procedures as were used by Sellers in preparing their financial statements and shall be consistent with and reflect the valuation methodology described in the Risk Policy and other methods, standards, policies and procedures described in, and using the same assumptions and gross reserves contained in, the electronic mark-to-market commodity valuation methodology files, complete and accurate copies of which are contained in the folder labeled "mark-to-market commodity valuation methodology folder" in the Data Room (the " **Commodity Valuation Methodology** ").

5.3.3. Sellers shall maintain in Jackson Prairie and the Montana Natural Gas Facility at least the minimum amount of working natural gas required pursuant to any agreement or tariff to ensure that from and after the Effective Time, Purchasers shall have the right to utilize the full capacity, including injection and withdrawal rights, of such storage facilities allocable to them pursuant to the terms of the applicable Assigned Contracts and Jackson Prairie Capacity Release Agreement without penalty or diminution as a result of a failure to maintain at least such minimum amount of working natural gas.

5.4. **Access to Information.**

Prior to the Effective Time, Sellers shall cooperate and make available to each Purchaser and its Representatives, upon reasonable notice and during normal business hours, (i) all books, records and information of Sellers relating to the Acquired Assets, (ii) such appropriate officers and employees of Sellers as requested by Purchasers, and (iii) such other information concerning the Acquired Assets as Purchasers and such Representatives may reasonably request.

5.5. **Updates to Information.**

From the date hereof until the Effective Time, Sellers and Purchasers shall give each other prompt written notice of any development that could reasonably be expected to result in a failure of a condition to Sellers' or Purchasers' obligations set forth in Sections 3 , 4 , 7 and 8 .

5.6. **Data Room Preservation.**

Except as otherwise agreed by the Parties, Sellers shall prepare and promptly deliver to Purchasers one or more DVD discs containing complete and accurate copies of all materials in the Data Room as of five (5) Business Days prior to the Closing Date. Within ten (10) days following the Closing Date, Sellers shall deliver to Purchasers a DVD disc containing any updates to the Data Room between the aforementioned date and the Closing Date.

5.7. **No Change in Accounting Methodologies; Credit Policy or Risk Policy.**

Sellers shall not make any changes to their financial accounting methods, except as required by Law or by GAAP to the extent failure to adopt such changes would cause such financial accounting methods not to be in accordance with GAAP with the concurrence of its independent accountants and after notice to Purchasers, or Risk Policy from the date hereof through the Effective Time. Sellers shall conduct their operations in material compliance with its Credit Policy and Risk Policy as applied on a consistent basis and in accordance with past practice.

5.8. **Exclusivity.**

From the date hereof through the Effective Time, Sellers will not (and Sellers will not cause or permit any of their Affiliates, and their respective officers, directors, representatives or agents to) solicit, initiate or encourage the submission of any proposal or offer from any Person relating to the acquisition of any capital stock or other voting securities, or any of the Acquired Assets (other than Commodities and Tangible Assets sold in the ordinary course of business) of, either of the Sellers, including any acquisition structured as a purchase, consolidation, exchange of membership interests, or share exchange.

5.9. **Data Privacy.**

5.9.1. None of the Purchasers shall use the Disclosed Personal Information for any purposes other than those related to the performance of this Agreement and the completion of the transactions contemplated hereunder.

5.9.2. Purchasers and Sellers acknowledge and confirm that the disclosure of Personal Information is necessary for the purposes of determining if the Parties shall proceed with the transactions contemplated hereunder, and that the disclosure of Personal Information relates solely to the carrying of the operations in Canada or the completion of the transactions contemplated hereunder.

5.9.3. Purchasers shall at all times keep strictly confidential all Disclosed Personal Information, and shall instruct those employees responsible for processing such Disclosed Personal Information to protect the confidentiality of that information in a manner consistent with Purchasers' obligations hereunder. Purchasers shall ensure that access to the Disclosed Personal Information shall be restricted to those employees or service providers of Purchasers who have a *bona fide* need to access that information.

5.9.4. Coral Canada undertakes, after the Closing Date, to utilize the Disclosed Personal Information only for the purposes for which the Disclosed Personal Information was initially collected.

5.9.5. If the closing of the transactions contemplated herein does not occur, Purchasers shall immediately cease to use all of the Disclosed Personal Information and will destroy in a secure manner, the Disclosed Personal Information (and any copies thereof, provided, however, that automatic computer back-up tapes may be permitted to expire in accordance with normal procedures) and shall provide Sellers with a certificate of a senior officer of each Purchaser confirming that destruction.

5.10. **Release of Credit Support.**

5.10.1. Prior to the Closing Date:

(a) Purchasers agree to exercise commercially reasonable efforts necessary or desirable in order to permit all Credit Support relating solely to Sellers' obligations under the Assigned Contracts, including those provided by either or both of Avista Corporation and Avista Capital, to be terminated and released, contingent upon consummation of the transactions contemplated herein and effective as of the Effective Time upon terms and conditions currently in place with such Counterparties. In the event that Purchasers are unable to replace any such Credit Support prior to the Closing Date, Purchasers, Sellers and Avista Capital shall enter into an indemnification or reimbursement agreement whereby any such Credit Support obligations shall be assumed by Purchasers. Purchasers and Sellers shall cooperate with each other in seeking BNP Paribas' consent to the substitution of one or more Purchasers for one or more Sellers under such Seller's or Sellers' outstanding letters of credit pursuant to a reimbursement or other similar arrangement.

(b) Purchasers and Sellers agree to exercise commercially reasonable efforts to transfer any rights to Pre-Paid Deposits to Purchasers.

(c) Purchasers and Sellers agree to exercise commercially reasonable efforts necessary or desirable in order to permit the assignment of their rights under any Counterparty Credit Support to Purchasers.

(d) Purchasers and Sellers agree to exercise commercially reasonable efforts to transfer any rights to Counterparty Pre-Paid Deposits to Purchasers.

Each such assignment or transfer shall be contingent upon consummation of the transactions contemplated herein and effective as of the Effective Time.

5.10.2. Following the Closing Date, Sellers and Purchasers shall continue to exercise commercially reasonable efforts, in conjunction with Counterparties as necessary or appropriate, to have all remaining Pre-Paid Deposits and Counterparty Pre-Paid Deposits assigned, transferred, repaid, substituted for alternative credit or otherwise eliminated. On or before seven (7) Business Days after the Effective Time, a payment, if required, shall be made to settle any remaining Pre-Paid Deposits and Counterparty Pre-Paid Deposits equal to the total amount of remaining Pre-Paid Deposits minus the total amount of remaining Counterparty Pre-Paid deposits. If this difference is a positive number, the amount of the difference shall be paid by Purchasers to Sellers. If the difference is a negative number, the amount of the difference shall be paid by Sellers to Purchasers.

6. Post-Closing Covenants

From the date hereof through the time frames specified herein, the Parties covenant and agree as follows:

6.1. **Transitional Services.**

The Parties each recognize that certain post-closing transitional services will be needed by Purchasers from Sellers and their Affiliates and that Sellers may need some post-closing transitional services from Purchasers. The Parties agree to cooperate and work together in good faith to provide the necessary transitional services to each other, provided such service requirements do not last beyond a period of six months unless extended by mutual agreement of the Parties, upon terms and conditions reasonably satisfactory to each Party. Each Party acknowledges that it is the intent that such services will be provided to each other at their approximate cost and may include services currently received by Sellers from their Affiliates.

6.2. **Customer Inquiries; Referrals.**

Neither Seller shall take any action that is designed or intended to have the effect of discouraging any lessor, licensor, customer, supplier or other business associate of such Seller from maintaining the same business relationships with Purchasers, as applicable, after the Closing Date as it maintained with such Seller prior to the Closing Date. Sellers will refer all customer inquiries relating to the Acquired Assets to Purchasers from and after the Closing Date. For one year after the Closing Date:

6.2.1. Sellers shall amend their web site(s) to redirect any person looking for information and/or contacts related to the Acquired Assets or Assumed Liabilities to such web site(s) designated by Purchasers, and

6.2.2. Sellers shall redirect incoming e-mail addressed to any Person previously employed or who otherwise was under contract with Sellers who is, as of the Effective Time, employed or otherwise under contract with Purchasers, including any independent contractors, to such account or accounts designated by Purchasers.

6.3. **Use of Name.**

Purchasers acknowledge that Purchasers shall not have any rights to the name "Avista". Purchasers and Sellers shall be entitled to refer to Purchasers, as the purchasers of substantially all of Avista Energy's former marketing and trading business. In the event that the provisions of Section 2.6 apply, Purchasers shall be entitled to refer to themselves as Avista Energy's or Avista Canada's (as applicable) authorized agent or representative.

6.4. **Confidential Information.**

6.4.1. Except as set forth below, for two years from and after the Closing Date, with respect to any and all information, matters or things of a confidential or proprietary nature concerning the Acquired Assets or the Assumed Liabilities, and not generally known or available to the public, Sellers and their Representatives shall keep any such data or information in confidence. Except as set forth below, for two years from and after the Closing Date, with respect to any and all information, matters or things of a confidential or proprietary nature concerning the Excluded Assets or the Retained Liabilities, and not generally known or available to the public, Purchasers and their Representatives shall keep any such data or information in confidence. Unless otherwise expressly provided in this Agreement, the terms and conditions of any other confidentiality agreement by which any Person may be bound shall not be modified or reduced by this Section 6.4 .

6.4.2. With respect to the obligations under this Section 6.4, in the event a Party is requested or required (by oral question or request for information or documents in any legal proceeding, interrogatory, subpoena, civil investigative demand or similar process by a Governmental Authority or other Person, including disclosure to state or federal regulatory authorities, disclosure pursuant to the rules of the Securities and Exchange Commission or any national securities exchange on which a Party or its Affiliate's securities may be traded or to ratings agencies), to disclose any such information, such Party shall use commercially reasonable efforts to notify the other Parties promptly of such request or requirement and provide the other Parties with an opportunity to resist such request or requirement.

6.4.3. The obligations of restricted use and strict confidentiality set forth herein shall not extend to any information which: (i) is legally in the possession of a Party independent of the transactions contemplated hereunder prior to the Effective Time; (ii) is independently developed by a Party or its employees, consultants, Affiliates or agents; (iii) is in or enters the public domain through no fault of such Party or others within its control; (iv) is disclosed to a Party, without restriction or breach of the confidentiality obligations herein or any other obligation of confidentiality, by a third party who has the right to make such disclosure; or (v) is required to be disclosed in the course of any rate making proceeding of Sellers or their Affiliates.

6.4.4. Purchasers shall return or destroy all copies, whether physical or electronic, all materials that do not pertain, directly or indirectly to the Acquired Assets or Assumed Liabilities, the Transaction Agreements or the transactions contemplated hereunder.

6.5. **Plan for Transition of Employment.**

Purchasers and Sellers shall implement the plans for transition of employment set forth in Exhibits D-1 and D-2.

6.6. **Transfer Taxes.**

6.6.1. The Party legally responsible for a Transfer Tax shall be responsible for the timely payment of such Transfer Tax resulting from the transactions contemplated by this Agreement.

6.6.2. Purchasers shall be liable for and shall pay to Sellers an amount equal to any GST and PST payable by Purchasers and collectible by Sellers in connection with the transactions contemplated by this Agreement.

6.6.3. Purchasers acknowledge and agree that they are responsible for and shall pay all GST and PST pertaining to this transaction at Closing. The Parties shall execute and deliver such documents, notices and elections and do such lawful things, to endeavor to allow Purchasers to claim a full input tax credit with respect to, or obtain a refund of all GST so payable by Purchasers.

6.7. **Tax Matters.**

6.7.1. Other than any Taxes that may be imposed on Purchaser under Section 6.6, Sellers shall be solely liable for any Taxes attributable to any Acquired Assets with respect to any taxable period or portion thereof ending on or before the Effective Time, including any such Taxes attributable to such Assigned Contracts for a taxable period beginning before and ending after the Effective Time, which is allocable to the portion of such period occurring on or before the Effective Time.

6.7.2. Purchasers shall be solely liable for any Taxes attributable to any Acquired Assets with respect to any taxable period or portion thereof beginning after the Effective Time, including any such Taxes attributable to such Assigned Contracts for a taxable period beginning before and ending after the Effective Time, which is allocable to the portion of such period occurring after the Effective Time.

6.8. **Tax Certificates, etc.**

The Parties agree, upon request, to use their commercially reasonable efforts to obtain any certificate or other document as may be lawfully available to mitigate, reduce or eliminate any Taxes that could be imposed as a result of the transactions contemplated by the Transaction Agreements.

6.9. **Accounts Receivable and Accounts Payable.**

6.9.1. Accounts receivable generated by and accruing under the Assigned Contracts relating to periods prior to the Effective Time are not being transferred to Purchasers and shall be invoiced by Sellers and all payments received thereon shall belong to Sellers. All accounts payable of Sellers generated by and accruing under the Assigned Contracts relating to periods prior to the Effective Time shall remain the responsibility of Sellers.

6.9.2. Accounts receivable generated by and accruing under the Assigned Contracts on and after the Effective Time shall be invoiced by Purchasers and all payments received thereon shall belong to Purchasers. All accounts payable generated by and accruing under the Assigned Contracts on or after the Effective Time are the responsibility of Purchasers.

6.9.3. In the event that any Seller at any time receives any payment which is payable in whole or in part to any Purchaser pursuant to this Section 6.9 , such payment shall be held in trust for such Purchaser and such Seller shall pay to such Purchaser, as soon as reasonably possible but in no event later than five (5) days after receipt by such Seller, the amount of the payment due such Purchaser, plus interest on such amount calculated at the Applicable Rate from the date of receipt of such payment by such Seller to the date on which payment is made to such Purchaser, pursuant to this Section 6.9 together with whatever supporting information is reasonably available. Similarly, if any Purchaser receives any payment that is payable in whole or in part to any Seller pursuant to this Section 6.9 , such Purchaser shall hold such payment in trust for such Seller and pay such Seller, as soon as reasonably possible but in no event later than five (5) days after receipt by such Purchaser, the amount of the payment due to such Seller, plus interest on such amount calculated at the Applicable Rate from the date of receipt of such payment by such Purchaser to the date on which payment is made to such Seller, pursuant to this Section 6.9 together with whatever supporting information is reasonably available.

6.10. **Pipeline Imbalances**

Purchasers and Sellers recognize that various pipeline companies periodically reconcile their imbalance accounts between (a) the quantities of gas nominated by shippers for flow and (b) the quantities of gas actually received and delivered for the account of a shipper and that, as a consequence of such reconciliation and depending on the circumstances, a shipper will be obligated to provide "in-kind makeup" (*i.e.*, deliver to, or receive from, the pipeline such quantities of gas as are necessary to eliminate the imbalance) or to make or receive "cashout" payments (payments made to or received from the pipeline to resolve the imbalance). To the extent any such reconciliation relates to gas transportation or storage occurring with respect to an Assigned Contract prior to the Effective Time or the value of the Natural Gas Inventory as of the Closing Date, (a) such Purchaser shall reimburse such Seller for any cash-out payments or the fair market value in cash of any gas received by such Purchaser relating to any such reconciliation as soon as possible, but in no event later than 30 days after receipt by such Purchaser of such cash-out payment or gas and (b) such Seller shall reimburse such Purchaser for any cash-out payments or the fair market value in cash of any gas delivered by such Purchaser relating to any such reconciliation as soon as possible after receiving notice thereof from such Purchaser, but in no event later than 30 days after receipt by such Seller of such notice. This Section 6.10 shall only be applicable from the Effective Time through ninety days after the Effective Time. Sellers shall use commercially reasonable efforts to minimize the pipeline imbalances before the Effective Time.

6.11. **Deemed Assignment of Contracts.**

The Parties agree to implement the provisions of Section 2.6.

7. **Purchasers' Conditions to Closing.**

The obligation of Purchasers to close the transactions contemplated hereunder and in the Transaction Agreements is subject to the fulfillment, on or before the Effective Time, of each of the conditions set forth in this Section 7 (except to the extent waived in writing by each Purchaser in its sole discretion, or as otherwise specifically limited below).

7.1. **Representations and Warranties**

Each of the representations and warranties made by Sellers in Section 3 of this Agreement shall be true in all material respects on and as of the Closing Date as though made on and as of such date or, in the case of representations and warranties made as of a specified date earlier than the Closing Date, on and as of such earlier date.

7.2. **Performance.**

Sellers shall have performed and complied, in all material respects, with the agreements, covenants and obligations required by this Agreement to be so performed or complied with by Sellers at or before the Effective Time.

7.3. **Deliveries.**

Sellers shall have made all deliveries required of them under Section 2.10.

7.4. **Orders and Laws.**

There shall not be any litigation or proceedings (filed by a Person other than Purchasers or their Affiliates) or Law or order restraining, enjoining or otherwise prohibiting or making illegal or threatening to restrain, enjoin or otherwise prohibit or make illegal the consummation of any of the transactions contemplated by this Agreement.

7.5. **Consents and Approvals.**

The approvals, consents and authorizations listed in Section 3.3.5 of the Seller Disclosure Schedule and on Schedules 2.2.1(d) and 2.10.16 shall have been duly obtained, made or given and shall be in full force and effect, and all terminations or expirations of waiting or appeal periods imposed by any Governmental Authority shall have occurred.

8. **Sellers' Conditions to Closing.**

The obligation of Sellers to close the transactions contemplated herein and in the Transaction Agreements is subject to the fulfillment, on or before the Effective Time, of each of the conditions set forth in this Section 8 (except to the extent waived in writing by each Seller in its sole discretion, or as otherwise specifically limited below):

8.1. **Representations and Warranties.**

Each of the representations and warranties made by Purchasers in Section 4 of this Agreement shall be true in all material respects on and as of the Effective Time as though made on and as of such date or, in the case of representations and warranties made as of a specified date earlier than the Closing Date, on and as of such earlier date.

8.2. **Performance.**

Purchasers shall have performed and complied, in all material respects, with the agreements, covenants and obligations required by this Agreement to be so performed or complied with by Purchasers at or before the Effective Time.

8.3. **Deliveries.**

Purchasers shall have taken all actions and made all deliveries required of them under Section 2.11.

8.4. **Orders and Laws.**

There shall not be any litigation or proceedings (filed by a Person other than Sellers or their Affiliates) or Law or order restraining, enjoining or otherwise prohibiting or making illegal or threatening to restrain, enjoin or otherwise prohibit or make illegal the consummation of any of the transactions contemplated by this Agreement.

8.5. **Consents and Orders.**

Any approvals, consents and authorizations required to be obtained by each Purchaser to execute and deliver this Agreement, perform its obligations hereunder and consummate the transactions contemplated hereby shall have been duly obtained, made or given and shall be in full force and effect, and all terminations or expirations of waiting or appeal periods imposed by any Governmental Authority shall have occurred.

9. **Termination.**

9.1. **Termination.**

9.1.1. By written agreement, Purchasers and Sellers may mutually agree to terminate this Agreement at any time prior to the Effective Time.

9.1.2. Either Purchasers or Sellers may terminate this Agreement and all of the Transaction Agreements prior to the Effective Time by giving written notice to the other Parties in the event that any Governmental Authority shall have issued an order or taken any other action restraining, enjoining or otherwise prohibiting the transactions contemplated herein or by the Transaction Agreements and such order shall have become final and non-appealable.

9.1.3. Sellers may terminate this Agreement prior to the Effective Time if Purchasers fail to fulfill the conditions set forth in Section 8 no later then the Effective Time and such failure has not been cured within fifteen (15) days of written notice provided by Sellers to Purchasers of such failure.

9.1.4. Purchasers may terminate this Agreement prior to the Effective Time if Sellers fail to fulfill the conditions set forth in Section 7 no later then the Effective Time and such failure has not been cured within fifteen (15) days of written notice provided by Purchasers to Sellers of such failure.

9.2. **Effect of Termination.**

If this Agreement is validly terminated pursuant to Section 9.1.4 by Purchasers due to Sellers' failure to satisfy the condition set forth in Section 7.2 or by Sellers pursuant to Section 9.1.3 due to Purchasers' failure to satisfy the condition set forth in Section 8.2 , the terminating Party shall be entitled to all rights and remedies available to it under Law or equity; provided , however , that in no event shall any Party have any obligation or liability arising under this Agreement or relating to the Transaction Agreements (or any other agreement, document or certificate delivered in connection with the transactions contemplated by the Transaction Agreements) for any consequential, punitive, special or indirect loss or damage, including lost profits or lost opportunities, and each Party hereby expressly releases the other Parties from the same; provided , further , that the maximum aggregate liability of Sellers and their Affiliates under this Section 9.2 shall in no event exceed an amount equal to $30,000,000.

10. **Non-Competition Provision.**

10.1. **Restrictions on Replication or Expansion of the Business.**

10.1.1. Subject to Section 10.1.3, Sellers, Avista Capital and Avista Corporation, each for itself and on behalf of its Affiliates (collectively, the " **Avista Group** "), agree that for a period of sixty (60) calendar months beginning at the Effective Time, no member of the Avista Group will form or participate through ownership or any alliance, or internally, develop capabilities to replicate the business of the Sellers within the region of the Western Electric Coordinating Council (the " **Western Region** "). Such capabilities include, without limitation, (i) the development of sales force activity or marketing activity within the Western Region at wholesale or at the end-use level if geographically outside the Avista Group's utility service area, which shall include any service areas gained as a result of a merger, acquisition or other similar transaction, and (ii) dealing, market-making, clearing and brokering Commodity Transactions within the Western Region at wholesale or at the end-use level if geographically outside of the Avista Group's utility service area, which shall include any service areas gained as a result of a merger, acquisition or other similar transaction.

10.1.2. Subject to Section 10.1.3, Sellers, Avista Capital and Avista Corporation, each for itself and on behalf of its Affiliates, agree that for a period of sixty (60) calendar months beginning as of the Effective Time, each member of the Avista Group will not, either directly or indirectly, carry on or engage in, as an individual, owner, part-owner, manager, operator, employee, sales person, agent or other participant, in the business of marketing of natural gas and liquids derived therefrom, electricity, or any alternative energy source in the Western Region at wholesale or at the end-use level if geographically outside the Avista Group's utility service area, which shall include any service areas gained as a result of a merger, acquisition or other similar transaction.

10.1.3. Purchasers agree that in no event shall the activities and transactions undertaken in the ordinary and usual course by the Avista Group engaged in the regulated utility lines of business be construed as violating the covenants set forth in Sections 10.1.1 and 10.1.2 , including such activities that pertain only to the business of the utility, purchases of the Avista Group's deficit energy at wholesale, sales of the Avista Group's surplus energy at wholesale, sales of the Avista Group's control area services, ancillary services or other services as part of optimization of its resources or as part of acquisition of all or a materially (i.e., greater than 10%) portion of the output of a new resource, the continuation or extension of existing optimization transactions presently engaged in by the utility or the entry into any transmission projects. Additionally, Purchasers agree that the activities of Advantage IQ, Inc., related to its customers' electric, natural gas, telephone and other utility services shall not be construed as violating the covenants set forth in Sections 10.1.1 and 10.1.2 . Purchasers further agrees that in the event any member of the Avista Group succeeds to a line of business as a result of an acquisition transaction, purchase, reorganization or otherwise involving other lines of business and such line of business violates the covenants set forth in Sections 10.1.1 and 10.1.2 , then such member of the Avista Group shall have a period of one (1) year from the date of such event to discontinue or otherwise dispose of such offending line of business.

10.1.4. Sellers' optimization of the generating facility that is the subject of the Lancaster Energy Conversion Agreement upon expiration of that agreement is permissible without regard to the prohibitions set forth in Sections 10.1.1 and 10.1.2 .

10.1.5. Sellers, Avista Capital and Avista Corporation each acknowledge and agree that the restrictions set forth in this Section 10.1 are reasonably designed to protect Purchasers' substantial investment and are reasonable with respect to duration, geographical area and scope.

10.1.6. Avista Capital agrees that, for a period of sixty (60) calendar months beginning as of the Effective Time, it shall cause Avista Energy and Avista Turbine to refrain from conducting any business other than the businesses conducted by them as of the date of this Agreement.

10.2. **Remedies Upon Breach.**

In the event of breach by any Person of any of the provisions of Sections 10.1.1 and 10.1.2, Purchasers may, in addition to any other rights or remedies existing in its favor, apply to any court of competent jurisdiction for specific performance or injunctive or other relief in order to enforce or prevent any violations of the provisions of Sections 10.1.1 and 10.1.2 . In the event of a breach or violation by any such Person of any of the provisions of Sections 10.1.1 and 10.1.2 established by any court of competent jurisdiction, without reversal or appeal, the sixty month period described therein will be tolled with respect to such Person until such breach or violation is resolved.

11. **Public Announcements.**

From the date of this Agreement and for a period of six (6) months after the Closing Date, no Party shall issue any press release or make any public announcement relating to the subject matter of this Agreement or any of the Transaction Agreements except as may be agreed by at least one Seller and one Purchaser in advance in writing unless the disclosing Party believes in good faith that such public disclosure is required by applicable Law or any listing or trading agreement concerning its publicly-traded securities (in which case the disclosing Party will use its commercially reasonable efforts to advise the other Parties prior to making the disclosure). Notwithstanding anything to the contrary in the foregoing, following the Effective Time, any Party may make any public announcement relating to the subject matter of the transactions contemplated herein as it deems necessary or advisable in connection with the filing of its periodic and current reports with the Securities and Exchange Commission.

12. **Miscellaneous**

12.1. **No Third Party Beneficiaries.**

This Agreement shall not confer any rights or remedies upon any Person other than the Parties, and their respective successors and permitted assigns and any indemnified party pursuant to the Indemnification Agreement.

12.2. **Entire Agreement.**

This Agreement and the Transaction Agreements (including the documents referred to in this Agreement) constitute the entire agreement among the Parties and supersede any prior understandings, agreements or representations by or among the Parties, written or oral, to the extent they related in any way to the subject matter of this Agreement

12.3. **Succession and Assignment**

This Agreement shall be binding upon and inure to the benefit of the Parties named in this Agreement and their respective successors and permitted assigns. No Party may assign either this Agreement or any of its rights, interests or obligations under this Agreement without the prior written approval of the other Parties.

12.4. **Counterparts.**

This Agreement may be executed in one or more counterparts, each of which shall be deemed an original but all of which together will constitute one and the same instrument.

12.5. **Headings.**

The section headings contained in this Agreement are inserted for convenience only and shall not affect in any way the meaning or interpretation of this Agreement.

12.6. **Notices.**

All notices, Claims and other communications under this Agreement will be in writing. Any notice, Claim or other communication under this Agreement shall be deemed duly given if it is sent to the intended recipient as set forth below.

If to Sellers:

Avista Energy, Inc.
Avista Energy Canada, Ltd.
c/o Avista Capital, Inc.
1411 East Mission Avenue
Spokane, Washington 99202
Facsimile: (509) 495-4361
Attn.: President

With copies to:

Avista Corporation

1411 East Mission Avenue
Spokane, Washington 99202
Facsimile: (509) 495-4361
Attn: General Counsel

Avista Capital, Inc., as Guarantor
1411 East Mission Avenue
Spokane, Washington 99202
Facsimile: (509) 495-4361
Attn: General Counsel

and to:

Heller Ehrman LLP
701 Fifth Avenue, Suite 6100
Seattle, Washington 98104
Facsimile: (206) 447-0849
Attn.: Bruce M. Pym

If to Purchasers:

Coral Energy Holding, L.P.
Coral Energy Resources, L.P.
Coral Power, L.L.C.
4445 Eastgate Mall
Suite 100
San Diego, California 92121
Facsimile: 713-767-5699
Attn.: Senior Vice President

Coral Energy Canada Inc.
3500, 450-1st Street S.W.
Calgary, Alberta Canada
T2P 5H1
Facsimile: 403-716-3501
Attn: Senior Vice President

With a copy to:

Coral Energy Holding, L.P.
909 Fannin, Plaza Level 1
Houston, Texas 77010
Facsimile: 713-230-2900
Attn: General Counsel

Any Party may send any notice, Claim or other communication under this Agreement to the intended recipient at the address set forth above using personal delivery, expedited or overnight courier, messenger service, facsimile or ordinary mail, but no such notice, Claim or other communication shall be deemed to have been duly given unless and until it actually is received by or at the address or number of the intended recipient as specified in this Section 12.6 . Any Party may change the address to which notices, Claims and other communications under this Agreement are to be delivered by giving the other Parties notice in the manner set forth in this Agreement

12.7. **Governing Law.**

This Agreement shall be governed by and construed in accordance with the domestic laws of the State of New York without giving effect to any choice or conflict of law provision or rule (whether under 5-1401 and 5-1402 of the New York General Obligations Law or any other jurisdiction) that would cause the application of the Laws of any jurisdiction other than the State of New York.

12.8. **Amendments and Waivers.**

No amendment of any provision of this Agreement shall be valid unless the same shall be in writing and signed by all of the Parties. No waiver by any Party of any default, misrepresentation or breach of warranty or covenant under this Agreement, whether intentional or not, shall be deemed to extend to any prior or subsequent default, misrepresentation or breach of warranty or covenant under this Agreement or affect in any way any rights arising by virtue of any prior or subsequent such occurrence.

12.9. **Severability.**

Any term or provision of this Agreement that is invalid or unenforceable in any situation in any jurisdiction shall not affect the validity or enforceability of the remaining terms and provisions of this Agreement or the validity or enforceability of the offending term or provision in any other situation or in any other jurisdiction.

12.10. **Expenses.**

Except as expressly provided in this Agreement, each of the Parties will bear its own costs and expenses (including legal fees and expenses) incurred in connection with this Agreement and the transactions contemplated herein and by the Transaction Agreements.

12.11. **Specific Performance.**

Each of the Parties acknowledges and agrees that the other Parties would be damaged irreparably in the event any of the provisions of this Agreement are not performed in accordance with their specific terms or otherwise are breached. Accordingly, each of the Parties agrees that the other Parties shall be entitled to an injunction or injunctions to prevent breaches of the provisions of this Agreement and to enforce specifically this Agreement and its terms and provisions in any action instituted in any court of the United States or any state having jurisdiction over the Parties and the matter, in addition to any other remedy to which they may be entitled, at law or in equity.

*****

REMAINDER OF PAGE INTENTIONALLY LEFT BLANK

EXECUTED effective as of the date first above written.

CORAL ENERGY HOLDING, L.P.,
a Delaware limited partnership

By: /s/ Mark Hanafin
Name: Mark Hanafin
Title: President and Chief Executive Officer

CORAL ENERGY RESOURCES, L.P.,
a Delaware limited partnership

By: /s/ Mark Hanafin
Name: Mark Hanafin
Title: President and Chief Executive Officer

CORAL POWER, L.L.C.
a Delaware limited liability company

By: /s/ Mark Hanafin
Name: Mark Hanafin
Title: President and Chief Executive Officer

CORAL ENERGY CANADA INC.
an Alberta, Canada corporation

By: /s/ Arnold MacBurnie
Name: Arnold MacBurnie
Title: Senior Vice President

SIGNATURE PAGE TO PURCHASE AND SALE AGREEMENT

Purchase and Sale Agreement

AVISTA ENERGY, INC.,
a Washington corporation

By: /s/ Gary G. Ely
Name: Gary G. Ely
Title: Chairman and CEO

AVISTA ENERGY CANADA, LTD.,
An amalgamated corporation of the Province of Alberta, Canada

By: /s/ Gary G. Ely
Name: Gary G. Ely
Title: Director and CEO

By signing below, Avista Corporation hereby acknowledges and agrees to be bound by and comply with the provisions of Section 10 of this Agreement.

AVISTA CORPORATION,
a Washington corporation

By: /s/ Gary G. Ely
Name: Gary G. Ely
Title: Chairman and CEO

By signing below, Avista Capital, Inc. hereby acknowledges and agrees to be bound by and comply with the provisions of Section 10 of this Agreement.

AVISTA CAPITAL, INC.
a Washington corporation

By: /s/ Gary G. Ely
Name: Gary G. Ely
Title: Chairman, President and CEO

SIGNATURE PAGE TO PURCHASE AND SALE AGREEMENT

APPENDIX A – DEFINITIONS

As used in this Agreement, the following defined terms have the meanings indicated below:

"**Acquired Assets**" means those assets and obligations being expressly acquired and assumed as set forth below:

A. The Assigned Contracts:

i. The enabling agreements, active confirmations and open transactions supporting Sellers' Trade Book as of the Effective Time and other active or newly executed contracts;

ii. The Sellers' enabling agreements that may not have an open position as of the Effective Time, but under which one or more transactions have been consummated since September 30, 2005;

iii. All of Sellers' pipeline transportation agreements *except* for the Service Agreements Applicable to Firm Transportation Service Under Rate-Schedule FS-1 between Avista Energy and each of TransCanada PipeLines Limited (Alberta System)(Contract No. 2004175615-2) and TransCanada PipeLines Limited (British Columbia System)(Contract No. AVIS-F5), each dated November 1, 2004 with an aggregate maximum day delivery quantity of 27,841 giga joules/day and a service termination date of October 31, 2017;

iv. All of Sellers' transmission agreements as represented by those agreements *except* the Service Agreement for Point-to-Point Transmission executed by the United States of America Department of Energy acting by and through the Bonneville Power Administration and Avista Energy, Inc., as amended (Service Agreement No. 97TX-50002) for 250 MW of power originally dated July 25, 1997;

v. All of Sellers' energy management and associated agreements;

vi. The Natural Gas Intrastate Storage Service Agreement dated April 1, 2006 by and between NorthWestern Corporation doing business as NorthWestern Energy and Avista Energy, Inc. as may have been amended from time to time;

vii. Cochrane Extraction Agreement – Priority Gas letter agreement dated October 1, 2005 by and between Avista Energy Inc. and COCHRANE/EMPRESS V PARTNERSHIP; and

viii. Any contract or agreement incidental to the foregoing.

B. The Assumed Leases.

C. Office furniture utilized in the Spokane, Washington; Vancouver, British Columbia and Great Falls, Montana locations.

D. Any telemetry and other miscellaneous equipment utilized by Sellers to monitor generator facilities.

E. The software and computer hardware listed on Schedule A-1.

F. Customer lists, know-how and going concern value (excluding the "Avista" name).

G. Working Natural Gas Inventory.

"**Affiliate**" means a Person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with a Party. For this purpose, control means the direct or indirect ownership of, in the aggregate, fifty percent (50%) or more of voting capital.

"**Agency Agreement**" means the Agency Agreement to be agreed upon and entered into by Purchasers and Sellers in the form attached hereto as Exhibit A .

"**Agreement**" has the meaning set forth in the introduction to this Agreement.

"**Applicable Rate**" means the rate of interest determined by reference to the U.S. Dollar London Interbank Offer Rate (LIBOR) quoted on Bloomberg page BBAM applicable for the relevant one-month period (or any successor or substitute page of such publication, or any successor to or substitute for such publication, providing rate quotations comparable to those currently provided on such page of such publication) at approximately 11:00 a.m., London time, two (2) Business Days prior to the commencement of such interest period.

"**Arbitrator**" has the meaning set forth in Section 2.2.2(f).

"**Assigned Contracts**" means the contracts, transactions, confirmations or other agreements set forth in the definition of Acquired Assets which, when taken as a whole, represent substantially all of the business of the Sellers being acquired and assumed by Purchasers.

"**Assignments**" means the Assignment and Novation Agreements among the applicable Seller, Purchaser and Counterparty with respect to the Assigned Contracts, which shall be substantially in the form attached hereto as Exhibit B , together with such changes therein as may be mutually acceptable to the applicable Seller and Purchaser as individual circumstances warrant.

"**Assumed Leases**" means the leases for the office premises in Spokane, Washington, Great Falls, Montana and Vancouver, British Columbia.

"**Assumed Liabilities**" means all Claims, obligations and liabilities under or in connection with the Acquired Assets, including the Assigned Contracts, sold, transferred and conveyed from Sellers to Purchasers in accordance with the terms of this Agreement, to the extent such Claims, obligations or losses with respect to such Acquired Assets arise after the Effective Time, but not on or prior to the Effective Time.

"**Avista Canada**" has the meaning set forth in the introduction to this Agreement.

"**Avista Capital**" means Avista Capital, Inc., a Washington corporation.

"**Avista Energy**" has the meaning set forth in the introduction to this Agreement.

"**Avista Group**" has the meaning set forth in Section 10.1.1.

"**Avista Turbine**" means Avista Turbine Power, Inc.

"**BPA Transmission Agreement**" means that certain Service Agreement for Point-to-Point Transmission, Agreement No. 97TX-50002, dated on or about July 24, 1997 between Avista Energy, Inc. and the United States of America, Department of Energy, acting by and through the Bonneville Power Administration and Bonneville Power Administration, as amended or supplemented by the following:

Amendment No. 1 to Point-to-Point Transmission Service, Contract No 97TX-50002 dated June 20, 2000;

Amendatory Agreement No. 2—Service Agreement for Point to Point Transmission Service dated June 7, 2004;

Exhibit K—Revision No. 1 Special Provisions dated December 15, 2004;

Exhibit K—Revision No. 2 Special Provisions dated January 4, 2005;

Notification of Real Power Loss Provider dated February 14, 2005;

Revision 1, Exhibit C Table 1—Statement of Specifications for Long Term Firm Transmission Service dated July 5, 2000;

Revision 1, Exhibit C Table 2 -Statement of Specifications for Long Term Firm Transmission Service dated September 28, 2000;

Revision No 2, Exhibit C Table 1 dated May 11, 2004;

Revision No. 1—Exhibit J Ancillary Services dated September 30, 1997;

Revision No. 2—Exhibit J dated August 5, 1999;

Revision No. 4—Exhibit J Ancillary Services dated August 21, 2002;

Revision No. 5—Exhibit J Ancillary Services dated December 1, 2005; and

Service Agreement for Point to Point Transmission dated July 31, 1997.

"**Business Day**" means a day other than Saturday, Sunday or any day on which banks located in the State of New York are authorized or obligated to close.

"**Canada Tax Act**" means the *Income Tax Act* (Canada).

"**Canadian Pipeline Agreements**" has the meaning set forth in Section 2.5.

"**Canadian Pipelines**" has the meaning set forth in Section 2.5.

"**Canadian Withholding Tax Amount**" means an amount equal to the applicable withholding rate for the Purchased Taxable Canadian Property times the amount (if any) by which the Taxable Canadian Property Purchase Price exceeds the Canadian Withholding Tax Certificate Limit.

"**Canadian Withholding Tax Certificate**" means the tax clearance certificate issued by the CRA pursuant to section 116 of the Canada Tax Act.

"**Canadian Withholding Tax Certificate Limit**" means the certificate limit (as that term is used in subsection 116(2) of the Canada Tax Act) as set forth in the Canadian Withholding Tax Certificate with respect to the Purchased Taxable Canadian Property, provided however , that until the Canadian Withholding Tax Certificate is delivered to Purchasers, the Canadian Withholding Tax Certificate Limit shall be deemed to be zero.

"**Canadian Withholding Tax Escrow Agent**" means Stikeman, Elliott, LLP.

"**Canadian Withholding Tax Escrow Agreement**" means the Canadian Withholding Tax Escrow Agreement to be entered into by and among Avista Energy, Inc., Coral Energy Canada Inc. and the Canadian Withholding Tax Escrow Agent in substantially the form attached hereto as Exhibit P .

"**Canadian Withholding Tax Escrow Amount**" means an amount equal to the applicable withholding rate for the Purchased Taxable Canadian Property times the amount (if any) by which the Taxable Canadian Property Purchase Price exceeds the Canadian Withholding Tax Certificate Limit set forth in the application for the Canadian Withholding Tax Certificate (if any) provided to Purchasers at or before the Closing.

"**Canadian Withholding Tax Remittance Date**" means the later of (i) the 27th day following the end of the calendar month that includes the Closing Date; and (ii) such later date, in lieu of the deadline specified in subsection 116(5) or (5.3), as applicable, of the Canada Tax Act, that CRA confirms in writing to Purchasers, in form and substance acceptable to Purchasers, acting reasonably, provided that a copy of such confirmation has been delivered to Purchasers and the Canadian Withholding Tax Escrow Agent before the time described in (i) above.

"**Charter Documents**" means with respect to any Person, the articles of incorporation, amalgamation, organization or association and by-laws, the limited partnership agreement or the limited liability company agreement, including those that are required to be registered or lodged in the place of incorporation, organization or formation of such Person and which establish the legal personality of such Person or any such similar document.

"**Claim**" means any action, suit, proceeding, investigation, charge, complaint, claim or demand.

"**Closing Date**" shall mean the Business Day which includes the Effective Time or, if the day which includes the Effective Time is not a Business Day, the first Business Day which immediately precedes the day which includes the Effective Time.

"**Code**" means the Internal Revenue Code of 1986, as amended.

"**Commissioner**" means the Commissioner of Competition appointed pursuant to the Competition Act.

"**Commodity**" means natural gas, electricity and energy in any form (including capacity, installed capacity or any other ancillary service) related to electricity in all cases under the Assigned Contracts.

"**Commodity Service Agreements**" means agreements for asset optimization and energy management services related to the provision and management of Commodity Transactions excluding end-use natural gas customers in Montana and Canada.

"**Commodity Transactions**" means spot, forward, futures, option, park and loan, swap, exchange, sale, purchase and repurchase transactions, tolling transactions, energy conversion agreements, rights relating to the transportation, transmission or storage of any Commodity, ancillary products, foreign currency contracts used to mitigate currency exposure related to commodity purchases and sales denominated in Canadian dollars, and any combination of the foregoing and similar transactions involving Commodities and other commodities the price of which is substantially related to the price or availability of natural gas or electricity (including financial derivative products relating to the foregoing).

"**Commodity Valuation Methodology**" has the meaning set forth in Section 5.3.2.

"**Competition Act**" means the *Competition Act*, R.S.C. 1985, c. C-34(Canada), as amended.

"**Competition Act Approval**" means in respect of the transactions contemplated under this Agreement and the Transaction Agreements:

(a) an advance ruling certificate pursuant to Section 102 of the Competition Act has been issued by the Commissioner; or

(b) a "no action letter" has been received from the Commissioner stating that the Commissioner has determined that she does not at that time intend to make an application for an order under Section 92 of the Competition Act in respect of the purchase or assets sales contemplated hereunder, and waiving the notification obligations of the Parties under Part IX of the Competition Act pursuant to Section 113(c) of the Competition Act, failing which waiver, the notification material required by Part IX of the Competition Act shall have been filed and any applicable waiting period thereunder shall have expired or been earlier terminated.

"**Coral Canada**" has the meaning set forth in the introduction to this Agreement.

"**Coral Holding**" has the meaning set forth in the introduction to this Agreement.

"**Coral Power**" has the meaning set forth in the introduction to this Agreement.

"**Coral Resources**" has the meaning set forth in the introduction to this Agreement.

"**Counterparties**" means each of the Parties to the Assigned Contracts, other than Seller.

"**CRA**" means the Canada Revenue Agency.

"**Credit Agreement**" that certain Third Amended and Restated Credit Agreement, dated as of July 25, 2003, by and among BNP Paribas, as Administrative Agent, Collateral Agent, an Issuing Bank, and a Bank; Fortis Capital Corp., as Documentation Agent, an Issuing Bank, and a Bank; Natexis Banques Populaires, as a Bank; the other financial institutions which may become a party to such agreement from time to time and the Avista Energy and Avista Canada, as the Co-Borrowers, as such agreement has been amended or modified from time to time

"**Credit Policy**" means Sellers' policies and procedures related to credit and counterparty risk, and related mandates, directives and procedures adopted by each of the Sellers and in effect as of December 31, 2005, through the date of this Agreement, a copy of which is contained in the Data Room.

"**Data Room**" means the electronic data room by which Sellers delivered or provided documents and files to Purchasers and their authorized representatives.

"**Disclosed Personal Information**" means any Personal Information disclosed to Purchasers.

"**DOJ**" has the meaning set forth in Section 5.1.1(a).

"**Effective Time**" means, unless otherwise agreed to by the Parties in writing, the later of (i) 11:59 p.m. June 30, 2007 or (ii) 11:59 p.m. on the last day of the month following the date the Assignor and Assignee receive the necessary regulatory consents specified in Section 5.1 or, if such regulatory consents are received on or after the fifteenth day of the month, at 11:59 p.m. on the last day of the month following the month in which such regulatory consents are received.

"**Electronically Recorded Trade Book**" means Sellers' detailed listing of all Commodity Transactions of Sellers that form a portion of the basis for the "energy commodity assets" and "energy commodity liabilities" in Sellers' financial statements as such assets and liabilities may be determined on any date by applying the Commodity Valuation Methodology and as presented in an electronic format substantially similar to that provided to Purchasers as of March 31, 2007 on April 4, 2007.

"**Employee Arrangement**" means any arrangement, policy, practice, contract or agreement that is not an Employee Benefit Plan that provides fringe benefits, supplemental unemployment, bonus, incentive, profit-sharing, termination pay, severance, stock option, stock purchase, phantom stock, stock appreciation rights, deferred compensation, workers' compensation, retirement, life, health, welfare, leave, vacation, disability, death or similar employee benefits.

"**Employee Benefit Plan**" means (a) any non-qualified deferred compensation or retirement plan or arrangement that is an Employee Pension Benefit Plan, (b) qualified defined contribution retirement plan or arrangement that is an Employee Pension Benefit Plan, (c) qualified defined benefit retirement plan or arrangement that is an Employee Pension Benefit Plan (including any Multiemployer Plan) or (d) Employee Welfare Benefit Plan or material fringe benefit plan or program.

"**Employee Pension Benefit Plan**" has the meaning set forth in Section 3(2) of ERISA.

"**Employee Welfare Benefit Plan**" has the meaning set forth in Section 3(1) of ERISA.

"**ERISA**" means the Employee Retirement Income Security Act of 1974, as amended.

"**Escrow Agreement**" means the Escrow Agreement to be entered into between Purchasers, Sellers and Avista Corporation substantially in the form attached hereto as Exhibit O .

"**Estimate Date**" means last day of the month immediately preceding the month that includes the Effective Time.

"**Estimated Purchase Price**" has the meaning set forth in Section 2.2.2(a)(i).

"**Excluded Assets**" means all of the assets of the Sellers, other than the Acquired Assets, including the following:

1. Cash;
2. Accounts receivable generated by Sellers from transactions which occur prior to the Effective Time;
3. Software, hardware, licenses and permits other than those set forth in Schedule A-1;
4. Corporate records (other than the Assigned Contracts);
5. Historical goodwill as reflected on Sellers' balance sheet;
6. Confidentiality Agreements;
7. Enabling agreements under which no activity has occurred since August 31, 2005;
8. All employment contracts, severance agreements or employment related obligations except to the extent such obligations relate to the Avista Canada employees and are required by applicable Canadian Law to be assumed by Purchasers;
9. Agreement to extend the Agreement to Convey Ownership Interest in Jackson Prairie Storage Expansion originally dated October 5, 1998, by and between Avista Corporation and Avista Energy, Inc., as amended, and all amendments thereto and the extension thereof as set forth in Exhibit Q to be executed by and between Avista Corporation and Avista Energy prior to the Closing Date;
10. Cushion natural gas in Jackson Prairie;
11. Service Agreement for Point-to-Point Transmission executed by the United States of America Department of Energy acting by and through the Bonneville Power Administration and Avista Energy, Inc., as amended (Service Agreement No. 97TX-50002) for 250 MW of power originally dated July 25, 1997;
12. Service Agreements Applicable to Firm Transportation Service Under Rate-Schedule FS-1 between Avista Energy and each of TransCanada PipeLines Limited (Alberta System)(Contract No. 2004175615-2) and TransCanada PipeLines Limited (British Columbia System)(Contract No. AVIS-F5), each dated November 1, 2004 with an aggregate maximum day delivery quantity of 27,841 giga joules/day and a service termination date of October 31, 2017; and
13. All other contracts, agreements and assets, other than the Acquired Assets.

"**FERC**" shall mean the Federal Energy Regulatory Commission.

"**FERC Order Authorizing the Disposition of Jurisdictional Facilities Under Section 203 of the FPA**" means that certain filing made by Sellers as required pursuant to Section 203 of the FPA to the FERC substantially in the form attached hereto as Exhibit E authorizing Sellers to dispose of jurisdictional facilities as described therein and receipt of final approval from the FERC, without a right of review or appeal, approving such request unless otherwise waived by the Parties in writing.

"**Fixed Transactions**" means Commodity Transactions arising out of transmission, transportation, energy conversion, storage, storage facilities and tolling agreements and the Commodity Service Agreements.

"**FPA**" means the United States Federal Power Act, as amended.

"**FTC**" has the meaning set forth in Section 5.1.1(a).

"**GAAP**" means generally accepted accounting principles in the United States of America, consistently applied throughout the specified period.

"**Governmental Authority**" means any court, tribunal, arbitrator, authority, agency, commission, official or other regulatory body or instrumentality of the United States or Canada, any other nation or any domestic or foreign state, province, county, city or other political subdivision or similar governing entity.

"**GST**" means the goods and services tax imposed by the *Excise Tax Act* (Canada).

"**GTN Capacity Release Agreement**" means the Letter Agreement between Avista Energy, Inc. and Coral Energy Resources, L.P. for the Prearranged Temporary Release of Firm Transportation Capacity on Gas Transmission Northwest Corporation's System substantially in the form attached hereto as Exhibit F .

"**Guaranty**" means the Guaranty to be given by Avista Capital to Purchasers substantially in the form attached hereto as Exhibit G.

"**Indemnification Agreement**" means the Indemnification Agreement entered into by and among each of the Purchasers, each of the Sellers and Avista Turbine substantially in the form attached hereto as Exhibit H .

"**Interstate Pipeline and Storage Contracts**" has the meaning set forth in Section 2.4.

"**Intrastate Pipeline Contract**" means firm transportation contracts with pipelines located in the United States that are not subject to the jurisdiction of the FERC.

"**Investment Canada Act**" means the *Investment Canada Act* R.S., 1985, c. 28 (1st Supp.) (Canada), as amended.

"**IRS**" means the United States Internal Revenue Service.

"**Jackson Prairie**" means the Jackson Prairie gas storage facility, a natural gas storage facility located near Jackson Prairie, Lewis County, Washington.

"**Jackson Prairie Capacity Release Agreement**" means the Agreement to Release Jackson Prairie Storage Capacity between Avista Energy and Coral Resources in substantially the form attached hereto as Exhibit I .

"**Jackson Prairie Limited Jurisdiction Certificate**" means the limited jurisdiction certificate in substantially the form attached to this Agreement as Exhibit J issued by the FERC that authorizes Avista Energy to release storage capacity at Jackson Prairie to Coral Resources.

"**Knowledge**" means the actual knowledge of Sellers after reasonable investigation. For purposes of this definition, "actual knowledge" and "reasonable investigation" shall mean and are limited to actual knowledge, or such knowledge as Sellers should have possessed, based on due inquiry of those directors, officers and employees of Sellers and their Affiliates who are identified in the Seller Disclosure Schedule.

"**Lancaster Energy Conversion Agreement**" means the Energy Conversion Agreement between Avista Turbine and Coral Power in substantially the form attached hereto as Exhibit K .

"**Laws**" means any legislation, promulgation, constitution, law, ordinance, principle of common law, code, rule, regulation, order, pronouncement, statute or treaty of any Governmental Authority.

"**Lien**" means a lien, claim, charge, security interest or other encumbrance.

"**Loss**" means any and all judgments, losses, liabilities, amounts paid in settlement, damages, fines, penalties, deficiencies, and expenses (including interest, court costs, reasonable fees of attorneys, accountants and other experts or other reasonable expenses of litigation or other proceedings or of any Claim, default or assessment).

"**Manually Recorded Commodity Transactions**" means Sellers' detailed listing of Commodity Transactions of Sellers that, in conjunction with the Electronically Recorded Trade Book, forms the entire basis for the "energy commodity assets" and "energy commodity liabilities" in Sellers' financial statements, as such assets and liabilities may be determined on any date by applying the Commodity Valuation Methodology

"**Market Value**" means the mutually agreed prompt month forward price for the month following the month in which the Effective Time occurs, of (i) the Sumas, Washington first of the month index for Jackson Prairie storage inventory; (ii) the Terasen Exchange balances, and pipeline imbalances (excluding imbalances relating to Avista Canada), (iii) the AECO first of the month index minus $0.15 per MMBtu for Montana storage inventory and related pipeline imbalances and (iv) the AECO first of the month index for the Interior and PNG pipeline imbalances and Sumas first of the month index for the Lower Mainland pipeline imbalances. If the Parties cannot reach agreement, the price shall be the average mid-point of broker quotes from TFS Energy, LLC and Prebon Energy Inc.

"**Montana Natural Gas Facility**" means Sellers' rights to natural gas storage at the Dry Creek and Cobb, Montana storage facilities pursuant to the agreement dated April 1, 2006 between North Western Corporation doing business as North Western Energy and Avista Energy providing for 185,000 dekatherms of Dry Creek storage capacity and 555,000 dekatherms of Cobb storage capacity.

"**National Energy Board**" means the National Energy Board of Canada.

"**Natural Gas Inventory**" means working natural gas reduced by the volume in MMBtu of any exchange balances and increased or reduced by any pipeline imbalances.

"**Net Trade Book Value**" means the total "energy commodity assets" less "energy commodity liabilities" as reflected on Sellers' balance sheets prepared in accordance with GAAP.

"**NOVA/ANG Capacity Assignment**" means the Letter Agreement between Coral Energy Canada Inc. and Avista Energy, Inc. for the Prearranged Temporary Release of Firm Transportation Capacity on TransCanada Pipelines Limited's NOVA Gas Transmission Ltd. and Alberta Natural Gas pipeline systems substantially in the form attached hereto as Exhibit L .

"**Parties**" means each Purchaser and each Seller.

"**Permitted Liens**" means (a) statutory liens for current Taxes not yet due and payable, or being contested in good faith by appropriate proceedings, (b) mechanics', carriers', workers', repairers', and other similar liens imposed by law arising or incurred in the ordinary course of business for obligations which are not overdue for a period of more than thirty (30) days or which are being contested in good faith by appropriate proceedings and (c) other liens, charges, easements, restrictions or other encumbrances incidental to the operation of the business or ownership of the Acquired Assets which were not incurred in connection with the borrowing of money or the advance of credit and which, in the aggregate, do not materially detract from the value of the Acquired Assets or materially interfere with the use thereof or the operation of the business in each case taken as a whole.

"**Person**" means any natural person, corporation, general partnership, limited partnership, limited liability company, proprietorship, other business organization, trust, union, association or Governmental Authority.

"**Personal Information**" means individually identifiable information about an employee of Avista Canada, except for the employee's name or business contact information.

"**PST**" means the provincial sales tax payable under the British Columbia Social Service Tax Act.

"**Purchase Price**" has the meaning set forth in Section 2.2.

"**Purchased Taxable Canadian Property**" means any of the Acquired Assets that are considered "taxable Canadian property" within the meaning of subsection 248(1) of the Canada Tax Act and which are listed in Section 3.8 of the Seller Disclosure Schedule.

"**Purchasers**" has the meaning set forth in the introduction to this Agreement.

"**Representatives**" means the officers, employees, counsel, accountants, financial advisers and consultants of any Purchaser or any Seller or their Affiliates.

"**Retained Liabilities**" means all liabilities of Sellers and their Affiliates, other than Assumed Liabilities, including Claims, obligations and Losses under or in connection with (1) the Assigned Contracts transferred from Sellers to Purchasers in accordance with the terms of this Agreement, to the extent such Claims, obligations or Losses arise on or prior to the Effective Time, but not after the Effective Time, (2) all litigation matters in existence as of the Effective Time or which pertain to any matters arising on or before the Effective Time, (3) all accounts payable and (4) all debt, including, without limitation, the Credit Agreement.

"**Returns**" has the meaning set forth in Section 3.14.

"**Risk Policy**" means Sellers' Risk Policy, and related mandates, directives and procedures adopted by each of the Sellers and in effect as of December 31, 2005 through the date of this Agreement, a copy of which is filed in the Data Room.

"**Security Agreement**" means the Security Agreement to be entered into by and among each of the Purchasers and Avista Capital substantially in the form attached hereto as Exhibit M .

"**Seller Disclosure Schedule**" has the meaning set forth in Section 3.

"**Seller Employee Arrangement**" means each Employee Arrangement that is sponsored, maintained, or contributed to by Sellers.

"**Seller Employee Benefit Plan**" means each Employee Benefit Plan that is sponsored, maintained, or contributed to by Sellers.

"**Sellers**" has the meaning set forth in the introduction to this Agreement.

"**Tangible Assets**" has the meaning set forth in Section 2.2.1(b).

"**Taxable Canadian Property Purchase Price**" means the Purchase Price paid in exchange for the Purchased Taxable Canadian Property.

"**Taxes**" means all taxes, charges, fees, levies or other assessments imposed by any United States or Canadian federal, state, province or local or any foreign taxing authority, including income, excise, property, sales, transfer, franchise, payroll, withholding, social security or other taxes, including any interest, penalties, fines or additions attributable thereto or in respect of failure to comply with any requirement concerning Tax returns, other than any taxes for which Avista Energy may be liable solely by reason of being a member of an affiliated, consolidated, combined, unitary or similar tax filing group.

"**Taxing Authority**" has the meaning set forth in Section 3.14.

"**Trade Book**" means the Electronically Recorded Trade Book and the Manually Recorded Commodity Transactions.

"**Transaction Agreements**" means the following agreements:

(a) Jackson Prairie Capacity Release Agreement;

(b) Lancaster Energy Conversion Agreement;

(c) Indemnification Agreement;

(d) Security Agreement and ancillary documents;

(e) Escrow Agreement;

(f) Canadian Withholding Tax Escrow Agreement;

(g) Guaranty;

(h) Agency Agreement;

(i) NOVA/ANG Capacity Assignment;

(j) GTN Capacity Release Agreement; and

(k) Transition Services Agreement.

"**Transfer Taxes**" means all transfer, sales, use, goods and services, value added, documentary, stamp duty, real estate transfer, excise taxes and other similar Taxes, duties or charges including any interest, penalties, fines or additions attributable thereto or in respect of failure to comply with any requirement concerning such Taxes.

"**Transition Services Agreement**" means the Transition Services Agreement to be agreed upon and entered into by Purchasers and Sellers in the form attached hereto as Exhibit N .

"**U.S. Pipelines**" has the meaning set forth in Section 2.4.

"**Western Region**" has the meaning set forth in Section 10.1.1.

Index of Defined Terms

APPENDIX B – SELLER DISCLOSURE SCHEDULE

Exhibit G

Form of Guaranty

GUARANTY

This Guaranty Agreement (this "Guaranty") dated effective as of __________, 2007, is entered into by Avista Capital, Inc. ("Guarantor"), a Washington corporation, in favor of Coral Energy Holding, L.P., a Delaware limited partnership, Coral Energy Resources, L.P., a Delaware limited partnership, Coral Power, L.L.C., a Delaware limited liability company and Coral Energy Canada Inc., an Alberta corporation (each being a "Coral Entity" and collectively, the "Coral Entities").

Recitals:

A. Guarantor desires that the Coral Entities enter into the contracts and agreements listed on Attachment A hereto with affiliates of Guarantor including Avista Energy, Inc., Avista Energy Canada, Ltd. and Avista Turbine Power, Inc. (each being a "Guaranteed Party" and collectively, the "Guaranteed Parties"), as such contracts and agreements listed on Attachment A may be amended, supplemented, renewed, or extended, collectively, from time to time, the "Contracts"; and

B. The Guaranteed Parties are subsidiaries or affiliates of Guarantor and Guarantor will directly or indirectly benefit from the Contracts to be entered into between one or more of the Coral Entities and one or more of the Guaranteed Parties; and

C. The Guaranteed Parties and the Coral Entities are parties to an Indemnification Agreement of even date herewith with respect to certain obligations between such parties in respect of the Contracts (the "Indemnification Agreement").

NOW, THEREFORE, in consideration of the Coral Entities entering into the Contracts with Guaranteed Parties, Guarantor hereby covenants and agrees as follows:

1.**Guaranty**. Subject to the terms and conditions hereof, Guarantor hereby irrevocably and unconditionally guarantees the timely performance and payment when due of the obligations of Guaranteed Parties (the "Obligations") to the Coral Entities, as applicable, under the Indemnification Agreement with respect to the Contracts. To the extent that a Guaranteed Party shall fail to perform or pay any Obligation, Guarantor shall promptly cause the performance or pay to the applicable Coral Entity the amount due in accordance with the terms, conditions and limitations contained in the Indemnification Agreement. This Guaranty shall constitute a guarantee of payment and not of collection. Guarantor shall also be liable for the reasonable attorneys' fees and expenses of such Coral Entity's external counsel incurred in any successful effort to collect or enforce any of the obligations under this Guaranty.

2.**Limitations**. Guarantor's performance hereunder shall be limited to monetary payments arising out of the Obligations (even if such payments are deemed to be damages) and in no event shall Guarantor be subject hereunder to consequential, exemplary, equitable, loss of profits, punitive, or any other damages, except to the extent specifically provided in the Indemnification Agreement to be due from a Guaranteed Party. Guarantor waives any and all defenses, rights and benefits Guarantor might assert to avoid or limit liability on Guarantor’s obligations arising from the bankruptcy, insolvency, dissolution, or liquidation of Guaranteed Party. The aggregate amount of Guarantor’s liability under or in respect of this Guaranty shall in no event exceed Thirty Million Dollars (U.S.$30,000,000), in the aggregate, plus attorney’s fees and other expenses specified under Section 1 hereto and shall be calculated by including any amounts paid by any Guaranteed Party under the Indemnification Agreement, or collected on any collateral securing Guarantor’s obligations under this Guaranty, against such Thirty Million Dollar cap on Guarantor’s liability.

3.**Termination**. This Guaranty shall remain in full force and effect until April 30, 2011. No termination shall affect, release or discharge Guarantor’s liability with respect to any Obligations existing or arising prior to the effective date of termination.

4.**Nature of Guaranty**. The Guarantor’s obligations hereunder with respect to any Obligation shall not be affected by the existence, validity, enforceability, perfection, release, or impairment of value of any collateral for such Obligations. The Coral Entities shall not be obligated to file any claim relating to the Obligations owing to it in the event that a Guaranteed Party becomes subject to a bankruptcy, reorganization, or similar proceeding, and the failure of a Coral Entity to so file shall not affect the Guarantor’s obligations hereunder. In the event that any payment to a Coral Entity in respect of any Obligations is rescinded or must otherwise be returned in the event that a Guaranteed Party becomes subject to a bankruptcy, reorganization, or similar proceeding, Guarantor shall remain liable hereunder in respect to such Obligations as if such payment had not been made.

5.**Subrogation**. Guarantor waives its right to be subrogated to the rights of the Coral Entities with respect to any Obligations paid or performed by Guarantor until all Obligations have been fully and indefeasibly paid to the Coral Entities or otherwise terminated, subject to no rescission or right of return, and Guarantor has fully and indefeasibly satisfied all of Guarantor’s obligations under this Guaranty.

6.**Waivers**. Guarantor hereby waives any circumstance which might constitute a legal or equitable discharge of a surety or guarantor, including but not limited to (a) notice of acceptance of this Guaranty; (b) presentment and demand concerning the liabilities of Guarantor; (c) notice of any dishonor or default by, or disputes with, a Guaranteed Party; and (d) any right to require that any action or proceeding be brought against a Guaranteed Party or any other person, or to require that a Coral Entity seek enforcement of any performance against a Guaranteed Party or any other person, prior to any action against Guarantor under the terms hereof. Guarantor consents to the renewal, compromise, extension, acceleration, or other modification of the terms of a Contract, without in any way releasing or discharging Guarantor from its obligations hereunder. Except as to applicable statute of limitations, the time for bringing any claim under the terms of the Indemnification Agreement and duration of this Guaranty as provided in Section 3 above, no delay of a Coral Entity in the exercise of, or failure to exercise, any rights hereunder shall operate as a waiver of such rights, a waiver of any other rights, or a release of Guarantor from any obligations hereunder.

7.**REPRESENTATIONS**. Guarantor is a corporation duly organized and validly existing under the laws of the State of Washington. The execution, delivery and performance of this Guaranty have been duly authorized by all necessary corporate action on the part of Guarantor. This Guaranty constitutes the legal, valid and binding obligation of Guarantor enforceable against Guarantor in accordance with its terms (except that enforcement may be limited by bankruptcy, insolvency, reorganization, or similar laws affecting the enforcement of creditors' rights generally and general principles of equity, whether considered in a proceeding in equity or at law).

8**Notice**. Any payment demand, notice, correspondence or other document to be given hereunder by any party to another (herein collectively called "Notice") shall be in writing and delivered personally or mailed by certified mail, postage prepaid and return receipt requested, or by facsimile, to the addresses set forth below. Notice given by personal delivery or mail shall be effective upon actual receipt, or, if receipt is refused or rejected, upon attempted delivery. Notice given by facsimile shall be effective upon actual receipt if received during the recipient's normal business hours, or at the beginning of the recipient's next business day after receipt if not received during the recipient's normal business hours. All Notices by facsimile shall be confirmed promptly after transmission in writing by certified mail or personal delivery. Any party may change any address to which Notice is to be given to it by giving Notice as provided above of such change of address.

9.**Miscellaneous**. **THIS GUARANTY SHALL BE IN ALL RESPECTS GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAWS EXCEPT SECTIONS 5-1401 AND 5-1402 OF THE NEW YORK GENERAL OBLIGATIONS LAW.** No term or provision of this Guaranty shall be amended or modified except in a writing signed by Guarantor and each of the Coral Entities. A party may assign its rights and obligations hereunder only with the prior written consent of the Coral Entities, in the case of Guarantor, and Guarantor, in the case of any of the Coral Entities, and any attempted assignment without such prior written consent shall be null and void. Subject to the foregoing, this Guaranty shall be binding upon Guarantor, its successors and assigns, and shall inure to the benefit of and be enforceable by the Coral Entities, their successors and assigns. This Guaranty and the Indemnification Agreement embodies the entire agreement and understanding between Guarantor and the Coral Entities, and supersedes all prior guaranties issued by Guarantor in connection with the Contracts.

IN WITNESS WHEREOF, Guarantor has executed this Guaranty effective as of the date first herein written.

Avista Capital, Inc.

By: ______________________________

Name: ______________________________

Title: ______________________________

Address of: Coral Energy Holding, L.P.
Coral Energy Resources, L.P.
Coral Power, L.L.C.

909 Fannin, Plaza Level 1
Houston, Texas 77010
Attn: Credit Department
Fax No.:

Address of Guarantor: Avista Capital, Inc.

1411 East Mission Avenue
Spokane, Washington 99202
Attn: General Counsel
Fax No.: (509) 495-4361

Address of: Coral Energy Canada Inc.

Coral Energy Canada Inc.
3500, 450-1st Street S.W.
Calgary, Alberta Canada
T2P 5H1
Facsimile: 403-716-3501
Attn: Senior Vice President

Exhibit H

Form of Indemnification Agreement

INDEMNIFICATION AGREEMENT

THIS INDEMNIFICATION AGREEMENT (this "**Agreement**") is made and entered into as of June __, 2007. The parties to this Agreement (the " **Parties** ") are Coral Energy Holding, L.P., a Delaware limited partnership (" **Coral Holding** "), Coral Energy Resources, L.P., a Delaware limited partnership (" **Coral Resources** "), Coral Power, L.L.C., a Delaware limited liability company (" **Coral Power** "), and Coral Energy Canada Inc., a corporation of the province of Alberta, Canada (" **Coral Canada** " and, together with Coral Holding, Coral Resources and Coral Power, each a " **Coral Entity** " and together the " **Coral Entities** ," all of which are Affiliates of one another); and Avista Energy, Inc., a Washington corporation (" **Avista Energy** "), Avista Energy Canada, Ltd., an amalgamated corporation of the province of Alberta, Canada (" **Avista Canada** "), and Avista Turbine Power, Inc., a Washington Corporation (" **Avista Turbine** " and, together with Avista Energy and Avista Canada, each an " **Avista Entity** " and together the " **Avista Entities** ," all of which are Affiliates of one another). Capitalized terms used and not otherwise defined in this Agreement shall have the meanings given in the Purchase Agreement (defined below).

RECITALS

A. Avista Energy and Avista Canada, as Sellers, are entering into a Purchase and Sale Agreement of even date with the Coral Entities, as Purchasers (the " **Purchase Agreement** "), by which the Coral Entities will purchase substantially all of the operating assets of Avista Energy and Avista Canada.

B. Concurrently with the Parties' entry into this Agreement and as of the Effective Time:

1. Avista Energy, Avista Canada and the Coral Entities are entering into an Agency Agreement (the "**Agency Agreement**") pursuant to which Avista Energy and Avista Canada are appointing certain of the Coral Entities as their agents with respect to certain of the Assigned Contracts;

2. Avista Energy, Avista Canada and the Coral Entities are entering into a Post-Closing Transition Services Agreement (the "**Transition Services Agreement** ") pursuant to which Avista Energy and Avista Canada have agreed to provide certain services to the Coral Entities for a limited period of time;

3. Avista Turbine and Coral Power are entering into an Energy Conversion Agreement (the "**Lancaster Agreement**") pursuant to which Coral Power is agreeing to purchase from Avista Turbine the capacity and energy generated from that certain power generation facility located in Rathdrum, Idaho; and

4. Avista Energy and Coral Resources are entering into that certain Agreement to Release Jackson Prairie Storage (the "**JP Agreement** ") pursuant to which Coral Resources is obtaining from Avista Energy the right for a limited time to utilize the natural gas storage capacity held by Avista Energy located in Lewis County, Washington.

C. As part of the Purchase Agreement, the Agency Agreement, the Transition Services Agreement, the Lancaster Agreement and the JP Agreement (collectively, with the documents and agreements entered into pursuant to such agreements, the " **Transaction Agreements** "), the Coral Entities and the Avista Entities are entering into this Agreement setting forth the terms and conditions under which the Parties are agreeing to provide indemnification for certain events that may arise out of or relate to the Transaction Agreements.

IN CONSIDERATION of the mutual promises, representations, warranties and covenants set forth in this Agreement, the Parties, each intending to be legally bound, agree as follows:

1. Definitions. As used in this Agreement:

(a) "Adverse Consequence" means any and all damages, assessments, charges, penalties, fines, costs, payments, Liabilities, debts, obligations, Taxes, liens, losses, expenses, fees or newly-imposed business restrictions, including court costs and reasonable attorneys' fees and expenses, arising out of or relating to one or more Claims or Orders.

(b) "Claim" means any demand, claim, action, investigation, legal proceeding (whether at law or in equity) or arbitration of any kind whatsoever, whether fixed or contingent.

(c) "Liability" means any liability (whether known or unknown, asserted or unasserted, absolute or contingent, accrued or unaccrued, liquidated or unliquidated, criminal or civil, or due or to become due), including any liability for Taxes.

(d) "Order" means any order, ruling, writ, judgment, injunction, decree, stipulation, determination or award entered by or with any Governmental Authority.

(e) "Third-Party" means any Person (including without limitation Governmental Authorities) other than the Coral Entities and their Affiliates or the Avista Entities and their Affiliates.

2. Indemnification Provisions for Benefit of the Coral Entities. Avista Energy, Avista Canada and, with respect to the Lancaster Agreement only, Avista Turbine, and each of them, jointly and severally, shall indemnify, defend and hold harmless the Coral Entities and each of their Affiliates, successors, officers, directors, employees and agents (each a "Coral Indemnified Party") from and against the entirety of any Adverse Consequences any of them may suffer resulting from, arising out of, relating to, in the nature of, or caused by:

2.1 Breach of Representations and Warranties. Breach by Avista Energy or Avista Canada of one or more of its representations and warranties made in the Purchase Agreement, including, without limitation, any representation or warranty made in:

(a) Sections 3.1, 3.2 or 3.7 of the Purchase Agreement (the "**Title and Authority Representations**");

(b) Sections 3.14 or 3.15 of the Purchase Agreement (the "**Tax Representations**"); or

(c) Section 3.17 of the Purchase Agreement (the "**Environmental Representations**").

2.2 Coral Entity Claims. Claims of any Coral Entity, or Claims against any Coral Entity by Third Parties, resulting from, arising out of, relating to, in the nature of or caused by (a) any breach by (i) an Avista Entity of or default by it under any of its covenants contained in the Purchase Agreement, Agency Agreement or Transition Services Agreement, or (ii) any member of the Avista Group of or default by it under Section 10 of the Purchase Agreement, in each case as such covenants pertain to obligations arising or actions to be taken following the Effective Time, (b) with respect to Third Party Claims only, the ownership or operation of the Acquired Assets on or prior to the Effective Time, or (c) the ownership or operation by of the Excluded Assets or the Retained Liabilities prior to, on or after the Effective Time.

2.3 Claims under Lancaster and JP Agreements. Claims of any Coral Entity resulting from, arising out of, relating to, in the nature of or caused by any breach by an Avista Entity of or default by it under any of its representations, warranties and covenants contained in the Lancaster Agreement or the JP Agreement.

3. Indemnification Provisions for Benefit of the Avista Entities. The Coral Entities and each of them, jointly and severally, shall indemnify, defend and hold harmless the Avista Entities, their Affiliates, successors, officers, directors, employees and agents (each an "Avista Indemnified Party") from and against the entirety of any Adverse Consequences any of them may suffer resulting from, arising out of, relating to, in the nature of, or caused by:

3.1 Breach of Representations and Warranties. Breach by any of the Coral Entities of one or more of its representations and warranties made in the Purchase Agreement. The preceding obligations shall include, without limitation, breach of any representation or warranty made in Section 4.1 or 4.2 (the "Coral Authority Representations") or Section 4.7 (the "Coral Tax Representation") of the Purchase Agreement

3.2 Avista Entity Claims. Claims of any Avista Entity, or Claims against any Avista Entity by Third Parties, resulting from, arising out of, relating to, in the nature of or caused by any breach by a Coral Entity of or default by it under any of its covenants contained in the Purchase Agreement, the Agency Agreement or Transition Services Agreement as such covenants pertain to obligations arising or actions to be taken following the Effective Time, or the ownership or operation of the Acquired Assets and assumption of the Assumed Liabilities by the Coral Entities or their Affiliates after the Effective Time.

3.3 Claims under Lancaster and JP Agreements. Claims of any Avista Entity resulting from, arising out of, relating to, in the nature of or caused by any breach by a Coral Entity of or default by it under any of its representations, warranties and covenants contained in the Lancaster Agreement or the JP Agreement.

4. Claims for Indemnification; Matters Involving Third Parties.

4.1 Notice. If any Coral Indemnified Party or Avista Indemnified Party (the "Indemnified Party") becomes aware of any matter that may give rise to a Claim for indemnification under this Agreement (an "Indemnification Claim") against any of the Avista Entities or Coral Entities, as the case may be (the "Indemnifying Party"), then the Indemnified Party shall give prompt written notice to the Indemnifying Party of each such Claim, stating the nature of such Claim in reasonable detail and indicating the estimated amount, if practicable, of the loss related thereto. Delay on the part of the Indemnified Party in providing notice shall not relieve the Indemnifying Party from its obligations hereunder unless (and then only to the extent that) the Indemnifying Party is prejudiced or damaged by such delay.

4.2 Acceptance or Rejection. If Indemnifying Party does not accept or affirmatively rejects such Indemnification Claim within thirty (30) days of the date the Indemnified Party provides written notice of the Indemnification Claim to the Indemnifying Party, the Indemnified Party shall be free to seek enforcement of its rights to indemnification under this Agreement. If the Indemnifying Party agrees that it has an indemnification obligation but objects that it is obligated to pay only a lesser amount, the Indemnified Party shall nevertheless be entitled to recover promptly from the Indemnifying Party the lesser amount, without prejudice to the Indemnified Party's Claim for the difference.

4.3 Third Party Claims. If the Indemnification Claim results from a Third-Party Claim or proceeding, the Indemnifying Party will have the right to defend the Indemnified Party against the Third-Party Claim or proceeding with counsel of their choice reasonably satisfactory to the Indemnified Party so long as (i) the Indemnifying Party notifies the Indemnified Party in writing within thirty (30) days after the Indemnified Party has given notice of the Indemnification Claim that the Indemnifying Party will indemnify the Indemnified Party from and against the entirety of any Adverse Consequences, to the fullest extent required under this Agreement, the Indemnified Party may suffer resulting from, arising out of, relating to, in the nature of, or caused by the Indemnification Claim, (ii) the Indemnifying Party provides the Indemnified Party with evidence reasonably acceptable to the Indemnified Party that the Indemnifying Party will have the financial resources to defend against the Indemnification Claim and fulfill its indemnification obligations under this Agreement, and (iii) the Indemnifying Party conducts the defense of the Indemnification Claim actively and diligently.

4.4 Indemnified Party's Rights. So long as the Indemnifying Party is conducting the defense of the Indemnification Claim in accordance with this Agreement, (i) the Indemnified Party may retain separate co-counsel, at its sole cost and expense, and participate in the defense of the Indemnification Claim and (ii) the Indemnified Party will not consent to the entry of any judgment or enter into any settlement with respect to the Indemnification Claim without the prior written consent of the Indemnifying Party which consent will not be unreasonably withheld or delayed.

4.5 Failure to Defend. In the event the Indemnifying Party fails to conduct the defense of an Indemnification Claim that results from a Third-Party Claim or proceeding in accordance with this Agreement, (i) the Indemnified Party may defend against, and consent to the entry of any judgment or enter into any settlement with respect to, the Third-Party Claim or proceeding giving rise to the Indemnification Claim in any manner it may deem appropriate (and the Indemnified Party need not consult with, or obtain any consent from, any Indemnifying Party in connection with the same), (ii) the Indemnifying Party will have the obligation to reimburse the Indemnified Party promptly and periodically for the costs of defending against the Indemnification Claim (including reasonable attorneys' fees and expenses) and (iii) the Indemnifying Party will remain responsible for any Adverse Consequences the Indemnified Party may suffer resulting from, arising out of, relating to, in the nature of, or caused by the Indemnification Claim to the fullest extent provided in this Agreement.

5. Determination of Adverse Consequences. The Parties shall take into account the time value/cost of money (using the Applicable Rate as the discount rate) and also any net Tax benefits/costs in determining Adverse Consequences for purposes of this Agreement.

6. Claims that Related to Periods Both Before and After the Effective Time. The Parties have attempted to allocate their responsibility and indemnification obligations in respect of the Effective Time. To the extent that any Claims otherwise covered by this Agreement relate to both the period on and prior to the Effective Time and the period after the Effective Time, the Indemnification Claim resulting therefrom and the indemnification obligations in respect thereof shall be allocated to the Avista Entities in proportion to the period prior to the Effective Time and to the Coral Entities in proportion to the period after the Effective Time. If the proportion of indemnification obligations cannot be determined between the Parties in good faith, as set forth in this Section 6, such determination shall be submitted to the trier of such Claim which determination shall be final and binding as to the Parties.

7. Limitations on Liability.

7.1 Liability Threshold. Except as provided in the following sentence, and subject to Section 7.3 and 7.4, no Party shall be liable under this Agreement until the aggregate for all Indemnification Claims made by all Coral Indemnified Parties or Avista Indemnified Parties, as the case may be, under this Agreement is in excess of $150,000 and then only for such excess over the $150,000 aggregate threshold. Notwithstanding the foregoing liability threshold, the Avista Entities' indemnification obligations for the Title and Authority Representations, Tax Representations and as set forth in Sections 2.2 and 2.3, above, and the Coral Entities' indemnification obligations for the Coral Authority Representations and Coral Tax Representation and as set forth in Sections 3.2 and 3.3 , above, shall be not be subject to such liability threshold limitation, and may be exercised in respect of the "first dollar" of any Indemnification Claim.

7.2 Maximum Liability. Except as provided in the following sentence and Section 7.4, the maximum aggregate liability of the Indemnifying Parties to the Indemnified Parties under this Agreement shall in no event exceed an amount equal to $30,000,000. Notwithstanding the foregoing:

(a) the Avista Entities' indemnification obligations for the Title and Authority Representations and the Coral Entities' indemnification obligations for the Coral Authority Representations shall not exceed the Purchase Price; and

(b) the Avista Entities' indemnification obligations set forth in Section 2.2, above and the Coral Entities' indemnification obligations set forth in Section 3.2 , above, shall be unlimited in dollar amount.

7.3 Survival of Indemnification Rights. An Indemnification Claim under this Agreement must be made, if at all, prior to the expiration of the following time periods:

(a) In the case of Indemnification Claims under Section 2.2 and Section 3.2 for which a performance period is specified, the duration of such performance period;

(b) In the case of Indemnification Claims under Section 2.2 and 3.2 other than as set forth in Section 7.3(a) above, there shall be no expiration period under this Agreement;

(c) In the case of Indemnification Claims under Section 2.1 or 3.1, other than as set forth in Section 7.3(d) below, such Indemnification Claim must be made no later than 18 months after the Effective Time;

(d) In the case of Indemnification Claims with respect to any of the Title and Authority, Tax, Environmental and Coral Authority Representations and Coral Tax Representations, such Indemnification Claim must be made no later than the third (3rd) anniversary of the Effective Time; and

(e) In the case of Indemnification Claims under Section 2.3 and Section 3.3, such Indemnification Claim must be made no later than thirty (30) days following the term of such agreement.

Indemnification Claims shall be barred if not made prior to the above expiration dates, and all obligations of indemnification with respect to such Indemnification Claims shall terminate and be of no further force or effect if such Indemnification Claims are not made prior to such dates.

7.4 Certain Breaches Not Subject to Limitations. Claims for indemnification with respect to (i) fraud or (ii) intentional misrepresentation shall not be subject to any of the limitations set forth in Section 7.1, Section 7.2, Section 7.3, Section 8 or Section 9.

8. Exclusive Remedy. The rights of the Avista Entities and the Coral Entities to assert Indemnification Claims and to receive indemnification payments pursuant to this Agreement shall be their sole and exclusive right and remedy with respect to any breach by any other party of any representation, warranty or covenant contained in the Transaction Agreements, except for the rights provided to the Parties to seek injunctions to prevent breaches of the Transaction Agreements or to enforce specifically the Transaction Agreements, as provided therein, and in all cases subject to the limitations on liability established in this Agreement.

9. Consequential Damages Limitation. Except as provided in the following sentence, in no event shall any Party have any obligation or liability arising under or relating to the Transaction Agreements (or any other agreement, document or certificate delivered in connection with the transactions contemplated by the Transaction Agreements) or this Agreement for any consequential, punitive, special or indirect loss or damage, including lost profits or lost opportunities, and each Party hereby expressly releases the other Parties from the same. As between the Parties to this Agreement, Claims for indemnification with respect to Third-Party Claims under this Agreement shall not be subject to the limitations set forth in the previous sentence to the extent of such Claims by Third-Parties, but the Parties acknowledge and agree that nothing contained in this Agreement is intended to, nor shall be construed to, waive, modify, amend or release any independent waiver of such consequential damages as may exist with respect to such Third-Party Claims outside of this Agreement or create a right for any person to recover consequential damages.

10. Miscellaneous.

10.1 Reliance. Each of the Coral Entities and the Avista Entities expressly confirms and agrees that it has entered into this Agreement and assumes the obligations imposed on it hereby in order to induce the other Parties to enter into the Transaction Agreements, and each of the Coral Entities and each of the Avista Entities acknowledges that the other Parties are relying upon this Agreement in entering into the Transaction Agreements.

10.2 Entire Agreement. This Agreement, the Transaction Agreements (including the documents referred to therein) and the Guaranty, the Security Agreement and the Escrow Agreement constitutes the entire agreement between the Parties hereto with respect to the subject matter hereof and supersedes any prior understandings, agreements or representations by or among the Parties, written or oral, to the extent they related in any way to the subject matter of this Agreement and the Transaction Agreements.

10.3 Succession and Assignment. This Agreement shall be binding upon and inure to the benefit of the Parties named in this Agreement and their respective successors and permitted assigns. Except as provided in the next sentence, no party may assign either this Agreement or any of its rights, interests or obligations under this Agreement without the prior written approval of the other Parties. The Coral Entities and the Avista Entities shall be entitled to assign this Agreement and any and all of their rights and interests under it to any Affiliate without the prior written approval of the other Parties, but such an assignment shall not relieve, discharge or otherwise affect the duties and obligations of the assigning Party under this Agreement, all of which shall remain in full force and effect.

10.4 Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original but all of which together will constitute one and the same instrument.

10.5 Headings. The Section headings contained in this Agreement are inserted for convenience only and shall not affect in any way the meaning or interpretation of this Agreement.

10.6 Notices. All notices, Indemnification Claims and other communications under this Agreement will be in writing. Any notice, Indemnification Claim or other communication under this Agreement shall be deemed duly given if it is sent to the intended recipient as set forth below:

If to the Avista Entities to:

Avista Energy, Inc.
c/o Avista Corporation
1411 East Mission Avenue
Spokane, Washington 99202
Facsimile: (509) 495-4361
Attn.: General Counsel

With copies to:

Avista Capital, Inc.
1411 East Mission Avenue
Spokane, Washington 99202
Facsimile: (509) 495-4361
Attn.: General Counsel

and to:

Heller Ehrman LLP
701 Fifth Avenue, Suite 6100
Seattle, Washington 98104
Facsimile: (206) 447-0849
Attn.: Bruce M. Pym

If to the Coral Entities to:

Coral Energy Holding, L.P.
Coral Energy Resources, L.P.
Coral Power, L.L.C.
909 Fannin, Plaza, Level 1
Houston, Texas 77010
Facsimile: (713) 767-5699
Attn.: Senior Vice President

Coral Energy Canada Inc.
3500, 450 - 1st Street S.W.
Calgary, Alberta
T2P 5H1
Facsimile: 403-716-3501
Attn: Senior Vice President

With copies to:

Coral Energy Holding, L.P.
909 Fannin Street, Level 1
Houston, Texas 77010
Facsimile: (713) 767-5699
Attn.: General Counsel

Any party may send any notice, Indemnification Claim or other communication under this Agreement to the intended recipient at the address set forth above using personal delivery, expedited or overnight courier, messenger service, facsimile or ordinary mail, but no such notice, Indemnification Claim or other communication shall be deemed to have been duly given unless and until it actually is received by or at the address or number of the intended recipient as specified in this Section 10.6 . Any party may change the address to which notices, Indemnification Claims and other communications under this Agreement are to be delivered by giving the other Parties notice in the manner set forth in this Agreement.

10.7 Governing Law. This Agreement shall be governed by and construed in accordance with the domestic laws of the State of New York without giving effect to any choice or conflict of law provision or rule (whether under 5-1401 and 5-1402 of the New York General Obligations Law or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than the State of New York.

10.8 Amendments and Waivers. No amendment of any provision of this Agreement shall be valid unless the same shall be in writing and signed by the Avista Entities and the Coral Entities. No waiver by any party of any default under this Agreement, whether intentional or not, shall be deemed to extend to any prior or subsequent default under this Agreement or affect in any way any rights arising by virtue of any prior or subsequent such occurrence.

10.9 Severability. Any term or provision of this Agreement that is invalid or unenforceable in any situation in any jurisdiction shall not affect the validity or enforceability of the remaining terms and provisions of this Agreement or the validity or enforceability of the offending term or provision in any other situation or in any other jurisdiction. Without limiting the generality of the foregoing, this Agreement is intended to confer upon the Parties indemnification rights to the fullest extent permitted by applicable laws. In the event any provision hereof conflicts with any applicable law, such provision shall be deemed modified, consistent with the aforementioned intent, to the extent necessary to resolve such conflict.

10.10 Construction. The Parties have participated jointly in the negotiation and drafting of this Agreement. In the event an ambiguity or question of intent or interpretation arises, this Agreement shall be construed as if drafted jointly by the Parties and no presumption or burden of proof shall arise favoring or disfavoring any party by virtue of the authorship of any of the provisions of this Agreement. The words "includes" and "including" shall not be words of limitation. The Parties intend that each covenant contained in this Agreement shall have independent significance. If any party has breached any covenant contained in this Agreement in any respect, the fact that there exists another covenant relating to the same subject matter (regardless of the relative levels of specificity) that the party has not breached shall not detract from or mitigate the fact that the party is in breach of the first covenant.

10.11 Interpretation and Construction. In interpreting and construing this Agreement, the following principles shall be followed:

(a) examples shall not be construed to limit, expressly or by implication, the matter they illustrate;

(b) the terms "herein," "hereof," "hereby," and "hereunder," or other similar terms, refer to this Agreement as a whole and not only to the particular article, section or other subdivision in which any such terms may be employed;

(c) references to sections and other subdivisions refer to the sections and other subdivisions of this Agreement;

(d) no consideration shall be given to the captions of the sections, subsections, or clauses, which are inserted for convenience in locating the provisions of this Agreement and not as an aid in its construction;

(e) the word "includes" and its syntactical variants mean "includes, but is not limited to" and corresponding syntactical variant expressions and the term "and/or" shall mean "or";

(f) currency amounts referenced herein, unless otherwise specified, are in U.S. Dollars;

(g) whenever this Agreement refers to a number of days, such number shall refer to calendar days unless Business Days are specified;

(h) the plural shall be deemed to include the singular, and vice versa; and

(i) each exhibit, attachment, and schedule to this Agreement is a part of this Agreement, but if there is any conflict or inconsistency between the main body of this Agreement and any exhibit, attachment, or schedule, the provisions of the main body of this Agreement shall prevail.

EXECUTED effective as of the date first above written.

CORAL ENTITIES

CORAL ENERGY HOLDING, L.P.

By: ______________________________
Name: ______________________________
Title: ______________________________

CORAL ENERGY RESOURCES, L.P.

By: ______________________________
Name: ______________________________
Title: ______________________________

CORAL POWER, L.L.C.

By: ______________________________
Name: ______________________________
Title: ______________________________

CORAL ENERGY CANADA INC.

By: ______________________________
Name: ______________________________
Title: ______________________________

AVISTA ENTITIES

AVISTA ENERGY, INC.

By: ______________________________
Name: ______________________________
Title: ______________________________

AVISTA ENERGY CANADA, LTD.

By: ______________________________
Name: ______________________________
Title: ______________________________

AVISTA TURBINE POWER, INC.

By: ______________________________
Name: ______________________________
Title: ______________________________

<u>Exhibit M</u>

Form of Security Agreement

SECURITY AGREEMENT

This SECURITY AGREEMENT dated as of ______, 2007 (this "Security Agreement") is given by **Avista Capital, Inc.**, a Washington corporation (" Debtor "), in favor of **Coral Energy Holding, L.P.** , a Delaware limited partnership ("Coral"), for the benefit of Coral, **Coral Energy Resources, L.P.** , a Delaware limited partnership, **Coral Power, L.L.C.** , a Delaware limited liability company and **Coral Energy Canada Inc.** , an Alberta corporation (collectively, the " Coral Entities ").

RECITALS

A. Pursuant to that certain Guaranty dated ______, __, 2007, Debtor has agreed to guaranty certain Obligations of its affiliates, Avista Energy, Inc., Avista Energy Canada Ltd. and Avista Turbine Power, Inc. to the Coral Entities (the "Guaranty").

B. Debtor has agreed to grant to Coral for the benefit of the Coral Entities a security interest in certain of its property as provided herein.

C. Coral has agreed to act as agent for and on behalf of the Coral Entities for purposes of this Security Agreement.

AGREEMENT

For and in consideration of the promises and the agreements contained in this Agreement and for other good and valuable consideration, the receipt and sufficient of which are hereby acknowledged, the parties agree as follows:

1. Definitions. Capitalized terms used and not otherwise defined herein shall have the meanings ascribed to them as set forth in **Appendix A** attached to and made a part of this Security Agreement. In the absence of such definitions, any other terms used herein (whether or not capitalized) shall have the meaning ascribed to them by the Code to the extent the same are defined in the Code.

2. Grant of Security Interest. Debtor hereby grants to Coral for the benefit of the Coral Entities a first priority security interest in the Collateral to secure the Obligations including, without limitation:

   2.1. the prompt and complete payment of all Obligations;

   2.2. the timely performance and observance by Debtor of all covenants, obligations and conditions contained in the Guaranty; and

   2.3. without limiting the generality of the foregoing and to the fullest extent permitted under applicable law, the payment of all amounts, including without limitation, interest which constitutes part of the Obligations and would be owed by Debtor to one or more of the Coral Entities under the Guaranty but for the fact that they are unenforceable or not allowable due to the existence of a bankruptcy, reorganization or similar proceeding involving Debtor

and Debtor hereby agrees to deliver the Collateral to the Escrow Agent under the Escrow Agreement, to be held by the Escrow Agent as the Escrow Fund under the Escrow Agreement, for the benefit of the Coral Entities. Provided, however, that under no circumstances shall the aggregate of all such obligations secured by this Security Agreement, including the Obligations and any other amounts referred to above, exceed at any time an aggregate value of Twenty-Five Million Dollars ($25,000,000.00).

3. Substitute Collateral. Debtor shall be entitled at any time, and from time to time, to substitute any of the following, in form and substance reasonably acceptable to Coral, as substitute

collateral for the Collateral: (a) a cash deposit in an amount equal to Twenty-Five Million Dollars ($25,000,000.00); (b) an irrevocable letter of credit in a face amount equal to Twenty-Five Million Dollars ($25,000,000.00), issued by a U.S. commercial bank or the U.S. branch of a foreign bank, with such bank having a credit rating of at least A- from the Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.) or its successor, or a rating of at least A3 from Moody's Investor Services, Inc. or its successor, or (c) such other form of collateral security as Coral and Debtor may mutually agree upon. Upon completion of any such substitution of collateral, the substitute collateral shall become the "Collateral" hereunder, and Coral shall release, return, surrender, and otherwise terminate any security interest granted hereunder in, the property or instruments previous serving as "Collateral" hereunder.

4. <u>Authorization to File Financing Statements</u>. Debtor authorizes Coral to file with the Department of Licensing for the State of Washington an initial financing statement and continuation statements that (a) indicate the Collateral; and (b) provide any other information required by part 5 of Article 9 of the Code or as required by such other jurisdiction for the sufficiency or filing office acceptance of such financing statement or continuation statement, including whether Debtor is an organization, the type of organization and any organization identification number issued to Debtor. Debtor agrees to furnish any such information to Coral promptly upon the request.

5. <u>Covenants Concerning Debtor's Legal Status</u>. Debtor covenants with Coral as follows:

   5.1. Without providing at least 30 days prior written notice to Coral, Debtor will not change its name, its place of business or, if more than one, chief executive office, or its mailing address or organizational identification number if it has one;

   5.2. If Debtor does not have an organizational identification number and later obtains one, Debtor will promptly notify Coral of such organizational identification number; and

   5.3. Without providing at least 30 days prior written notice to Coral, Debtor will not change its type of organization, jurisdiction of organization or other legal structure.

6. <u>Representations and Warranties Concerning Collateral</u>. Debtor further represents and warrants to Coral as follows:

   6.1. Except for the security interests granted to Coral in this Agreement, Debtor owns good and marketable title to the Collateral free and clear of all Liens, and neither the Collateral nor any interest in the Collateral has been transferred to any other party. Debtor has full right, power and authority to grant a first-priority security interest in the Collateral to Coral in the manner provided in this Security Agreement, free and clear of any other Liens, adverse claims and options and without the consent of any other person or entity or if consent is required, such consent has been obtained. No other Lien, adverse claim or option has been created by Debtor or is known by Debtor to exist with respect to any Collateral; and to the best of Debtor's knowledge and belief no financing statement or other security instrument is on file in any jurisdiction covering such Collateral other than the security interest in favor of Coral under this Security Agreement. The security interest granted is a first lien security interest.

   6.2. There are no actions, suits or proceedings pending or threatened against or affecting the Collateral before any court or by or before any governmental department, commission, board, bureau, agency or instrumentality, domestic or foreign, which in any manner draws into question the validity of this Security Agreement.

7. <u>Covenants Concerning the Collateral</u>.

   7.1. Debtor covenants with Coral that while this Security Agreement remains in effect, that except for the security interest herein granted and the deposit of the Collateral with the Escrow Agent under the Escrow Agreement, Debtor is and shall be the owner of or have other transferable rights in the Collateral free from any right or claim of any other person or any Lien, security interest or other encumbrance, and Debtor shall defend the same against all claims and demands of all persons at any time claiming the same or any interest therein adverse to Coral. Debtor shall not pledge, mortgage or create, or suffer to exist any right of any person in or claim by any person to the Collateral, or any security interest, Lien or other encumbrance in the Collateral in favor of any person other than Coral; nor permit any person, other than Coral, to file any financing statement or security interest in the Collateral.

7.2. In the event of (a) a sale, transfer, disposition or reorganization of greater than 50% of the equity of Debtor's subsidiary, Advantage IQ, Inc, a Washington corporation ("Advantage"), (b) Debtor ceasing to own and control shares of stock of and other equity interests in Advantage representing a majority of the votes entitled to be cast by shareholders of Advantage and a majority of the equity value of Advantage, or (c) the sale, transfer or other disposition of the underlying assets of Advantage outside the ordinary course of business, Debtor agrees to replace the Collateral with substitute Collateral as set forth Section 3.

8. Securities and Deposits. Coral may at any time following and during the continuance of an Event of Default, at its option, transfer to itself or any nominee any securities constituting Collateral, receive any income thereon and hold such income as additional Collateral or apply it to the Obligations. Whether or not any Obligations are due, Coral may following and during the continuance of an Event of Default demand, sue for, collect or make any settlement or compromise that it deems desirable with respect to the Collateral.

9. Rights and Remedies. If an Event of Default shall have occurred and is continuing, Coral shall have in any jurisdiction in which enforcement hereof is sought, in addition to all other rights and remedies, the rights and remedies of a secured party under the Code and any additional rights and remedies as may be provided to a secured party in any jurisdiction in which Collateral is located, including, without limitation, the right to take possession of the Collateral.

10. No Waiver by Coral. Coral shall not be deemed to have waived any of its rights and remedies in respect of the Obligations or the Collateral unless such waiver shall be made in writing and signed by Coral. No delay or omission on the part of Coral in exercising any right or remedy shall operate as a waiver of such right or remedy or any other right or remedy. A waiver on any occasion shall not be construed as a bar to or a waiver of any right or remedy on any future occasion. All rights and remedies of Coral with respect to the Obligations or the Collateral, whether evidenced hereby or by any other instrument or papers, may be exercised by Coral, shall be cumulative and may be exercised singularly, alternatively, successively or concurrently at such time or at such times as Coral deems expedient.

11. Marshalling. Subject to the terms and conditions of this Security Agreement and the Indemnification Agreement, Coral shall not be required to marshal the Collateral, or other assurances of payment of the Obligations, or any of them or to resort to the Collateral or other assurance of payment in any particular order, and all of the rights and remedies hereunder and in respect of the Collateral and other assurances of payment shall be cumulative and in addition to all other rights and remedies, however existing or arising. **TO THE EXTENT THAT IT LAWFULLY MAY, DEBTOR HEREBY AGREES THAT IT WILL NOT INVOKE ANY LAW RELATING TO THE MARSHALLING OF COLLATERAL WHICH MIGHT CAUSE DELAY IN OR IMPEDE THE ENFORCEMENT OF CORAL'S RIGHTS AND REMEDIES UNDER THIS SECURITY AGREEMENT OR UNDER ANY OTHER INSTRUMENT CREATING OR EVIDENCING ANY OF THE OBLIGATIONS OR UNDER WHICH ANY OF THE OBLIGATIONS IS OUTSTANDING OR BY WHICH ANY OF THE OBLIGATIONS IS SECURED OR PAYMENT THEREOF IS OTHERWISE ASSURED, AND, TO THE EXTENT THAT IT LAWFULLY MAY, DEBTOR HEREBY IRREVOCABLY WAIVES THE BENEFITS OF ALL SUCH LAWS.**

12. Overdue Amounts. Until paid, all amounts due and payable by Debtor hereunder shall be a debt secured by the Collateral and shall bear, whether before or after judgment, interest determined by reference to the U.S. Dollar London Interbank Offer Rate (LIBOR) quoted on Bloomberg page BBAM applicable for the relevant one-month period (or any successor or substitute page of such publication, or any successor to or substitute for such publication, providing rate quotations comparable to those currently provided on such page or such publication) at approximately 11:00 a.m., London time, two Business Days prior to the commencement of such interest period.

13. Notices. All communications hereunder shall be in writing and may be delivered by hand delivery, United States mail, overnight courier service or facsimile. Notice by facsimile or hand delivery shall be effective on the day actually received, if received during business hours on a Business Day, and otherwise shall be effective at the beginning of the recipient's next Business Day. Notice by overnight United States mail or courier shall be effective on the next Business Day after it was sent to the appropriate notice address set forth below or at such other address as any party hereto may have furnished to the other party in writing:

If to the Coral Entities:

909 Fannin, Plaza Level 1
Houston, Texas 77010
Attn: General Counsel
Phone: (713) 767-5400
Fax: (713) 230-2900

If to Debtor:

Avista Capital, Inc.
1411 East Mission Avenue
Spokane, Washington 99202
Attention: General Counsel
Phone: (509) 495-8687
Facsimile: (509) 495-4316

14. Governing Law; Consent to Jurisdiction. **THIS SECURITY AGREEMENT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK, WITHOUT REFERENCE TO ITS CONFLICT OF LAWS PROVISIONS EXCEPT SECTIONS 5-1401 AND 5-1402 OF THE NEW YORK GENERAL OBLIGATIONS LAW** .

15. Term of Agreement. This grant of a security interest under this Security Agreement shall remain in full force until the later of January 1, 2009 or, in the event that any of the Coral Entities has made a claim under the Indemnification Agreement, the date such claim has been resolved and such amount owing, if any, has been paid. Upon expiration of this Security Agreement, Coral shall promptly return possession of the Collateral, if it then has possession of the same, to Debtor and file any applicable termination statements. Notwithstanding the foregoing, this Security Agreement shall continue notwithstanding the reorganization or bankruptcy of Debtor, or any other similar event or proceeding affecting Debtor.

16. Miscellaneous. The headings of each section of this Security Agreement are for convenience only and shall not define or limit the provisions thereof. This Security Agreement and all rights and obligations hereunder shall be binding upon Debtor and its successors and assigns and shall insure to

the benefit of the Coral Entities and their successors and assigns. No party may assign its interest in this Security Agreement without the prior written consent of Coral, in the case of Debtor, and Debtor, in the case of the Coral Entities. If any term of this Security Agreement shall be held to be invalid, illegal or unenforceable, the validity of all of the other terms shall in no way be affected and this Security Agreement shall be construed and enforceable as if such invalid, illegal or unenforceable term had not be included herein. This Security Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

17. Interpretation and Construction. In interpreting and construing this Security Agreement, the following principles shall be followed:

17.1. examples shall not be construed to limit, expressly or by implication, the matter they illustrate;

17.2. the terms “herein,” “hereof,” “hereby,” and “hereunder,” or other similar terms, refer to this Security Agreement as a whole and not only to the particular article, section or other subdivision in which any such terms may be employed;

17.3. references to sections and other subdivisions refer to the sections and other subdivisions of this Security Agreement;

17.4. the word “includes” and its syntactical variants mean “includes, but is not limited to” and corresponding syntactical variant expressions and the term “and/or” shall mean “or”;

17.5. whenever this Security Agreement refers to a number of days, such number shall refer to calendar days unless Business Days are specified;

17.6. the plural shall be deemed to include the singular, and vice versa; and

17.7. each exhibit, annex, attachment, and schedule to this Security Agreement is a part of this Security Agreement, but if there is any conflict or inconsistency between the main body of this Security Agreement and any exhibit, annex, attachment, or schedule, the provisions of the main body of this Security Agreement shall prevail.

*****

IN WITNESS WHEREOF, intending to be legally bound, Debtor has caused this Security Agreement to be executed as of the date first written above.

***

Avista Capital, Inc.

BY: ____________________

NAME: ____________________

TITLE: ____________________

Coral Energy Holding, L.P.

BY: ____________________

NAME: ____________________

TITLE: ____________________

APPENDIX A TO SECURITY AGREEMENT

DEFINITIONS

"Business Day" means any day other than a Saturday, Sunday or any day in which commercial banks in Houston, Texas are required or permitted by law to be closed and the Friday following the Thanksgiving holiday.

"Code" means the Uniform Commercial Code as currently in effect and as may be amended from time to time, in the State of New York.

"Collateral" means 13,770,285 of shares of common stock of Advantage (defined and described in Section 7.2 of this Security Agreement), which represents with respect to Advantage (a) 49.96% of its common stock and 46.53% of all of its equity interests, on an as-converted basis, currently outstanding, and (b) 38.68% of all of its equity interests calculated on an as-converted and fully diluted basis, in each case as measured by vote and value.

"Coral" has the meaning ascribed to it in the preface.

"Coral Entities" has the meaning ascribed to it in the preface.

"Debtor" has the meaning ascribed to it in the preface.

"Escrow Agreement" means that certain Escrow Agreement of even date herewith entered into by and among Coral, Debtor and Avista Corporation, as escrow agent (the "Escrow Agent"), for the purposes of establishing an escrow fund (the "Escrow Fund") consisting of the Collateral.

"Event of Default" means:

a. Any default or event of default under the Guaranty;

b. Any representation or warranty made by Debtor herein is false or misleading in any material respect when made;

c. Debtor's failure to comply with any of the provisions of this Security Agreement and such failure remains unremedied for three (3) Business Days after written notice thereof has been given to Debtor;

d. The transfer or disposition of any of the Collateral, except as expressly permitted by this Security Agreement;

e. The attachment, execution or levy on any of the Collateral, except as expressly permitted by this Security Agreement;

f. Debtor voluntarily or involuntarily becomes subject to any proceeding under any bankruptcy or insolvency statute; or

g. Debtor fails to comply with or becomes subject to any administrative or judicial proceeding under any federal, state or local (a) asset forfeiture or similar law which can result in the forfeiture of property; or (b) other law, where noncompliance may have any significant effect on the Collateral.

"Indemnification Agreement" means that certain Indemnification Agreement of even date herewith entered into by and among Avista Energy, Inc., Avista Energy Canada, Ltd., Avista Turbine Power, Inc. and the Coral Entities.

"Lien" means any mortgage, pledge, security interest, encumbrance, lien, claim or charge of any kind, whether or not filed, recorded or otherwise perfected under applicable law.

"Obligations" means all of the indebtedness, obligations and liabilities of Debtor to the Coral Entities arising or accruing under the Guaranty.

"Security Agreement" has the meaning ascribed to it in the preface.

EXHIBIT 12

AVISTA CORPORATION

Computation of Ratio of Earnings to Fixed Charges and Preferred Dividend Requirements
Consolidated
(Thousands of Dollars)

	12 months ended March 31, 2007	Years Ended December 31 2006	2005	2004	2003
Fixed charges, as defined:					
Interest expense	$ 87,073	$ 88,426	$ 84,952	$ 84,746	$ 85,013
Amortization of debt expense and premium—net	7,528	7,741	7,762	8,301	7,972
Interest portion of rentals	1,744	1,802	2,394	2,443	4,452
Total fixed charges	$ 96,345	$ 97,969	$ 95,108	$ 95,490	$ 97,437
Earnings, as defined:					
Income from continuing operations	$ 55,655	$ 73,133	$ 45,168	$ 35,614	$ 50,643
Add (deduct):					
Income tax expense	31,060	42,090	25,861	21,592	35,340
Total fixed charges above	96,345	97,969	95,108	95,490	97,437
Total earnings	$ 183,060	$ 213,192	$ 166,137	$ 152,696	$ 183,420
Ratio of earnings to fixed charges	1.90	2.18	1.75	1.60	1.88
Fixed charges and preferred dividend requirements:					
Fixed charges above	$ 96,345	$ 97,969	$ 95,108	$ 95,490	$ 97,437
Preferred dividend requirements (1)	—	—	—	—	1,910
Total	$ 96,345	$ 97,969	$ 95,108	$ 95,490	$ 99,347
Ratio of earnings to fixed charges and preferred dividend requirements	1.90	2.18	1.75	1.60	1.85

(1) Preferred dividend requirements have been grossed up to their pre-tax level. Effective July 1, 2003, preferred dividends are included in interest expense with the adoption of SFAS No. 150.

Exhibit 15

May 4, 2007

Avista Corporation
Spokane, Washington

We have reviewed, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the unaudited interim financial information of Avista Corporation and subsidiaries for the periods ended March 31, 2007 and 2006, as indicated in our report dated May 3, 2007; because we did not perform an audit, we expressed no opinion on that information.

We are aware that our report referred to above, which is included in your Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, is incorporated by reference in Registration Statement Nos. 2-81697, 2-94816, 033-54791, 333-03601, 333-22373, 333-58197, 033-32148, 333-33790, 333-47290, and 333-126577 on Form S-8, in Registration Statement Nos. 333-106491, 033-53655, 333-39551, 333-82165, 333-63243, 333-16353, 333-16353-01, 333-16353-02, 333-16353-03, 333-64652, 033-60136, 333-10040, 333-113501, and 333-139239 on Form S-3, and in Registration Statement Nos. 333-62232 and 333-82502 on Form S-4, and in AVA Formation Corp.'s Registration Statement No. 333-131872 on Form S-4.

We also are aware that the aforementioned report, pursuant to Rule 436(c) under the Securities Act of 1933, is not considered a part of the Registration Statement prepared or certified by an accountant or a report prepared or certified by an accountant within the meaning of Sections 7 and 11 of that Act.

/s/ Deloitte & Touche LLP

Seattle, Washington

Exhibit 31.1

CERTIFICATION

I, Gary G. Ely, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Avista Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2007

/s/ Gary G. Ely
Gary G. Ely
Chairman of the Board and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Malyn K. Malquist, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 4, 2007

/s/ Malyn K. Malquist

Malyn K. Malquist

Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32

AVISTA CORPORATION

CERTIFICATION OF CORPORATE OFFICERS
(Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)

Each of the undersigned, Gary G. Ely, Chairman of the Board and Chief Executive Officer of Avista Corporation (the "Company"), and Malyn K. Malquist, Executive Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: May 4, 2007

/s/ Gary G. Ely
Gary G. Ely
Chairman of the Board and Chief Executive Officer

/s/ Malyn K. Malquist
Malyn K. Malquist
Executive Vice President and Chief Financial Officer

Form 8-K

AVISTA CORP - ava

Filed: June 05, 2007 (period: May 25, 2007)

Report of unscheduled material events or corporate changes.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington D.C. 20549

FORM 8-K

CURRENT REPORT

PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934

Date of Report (Date of earliest event reported): May 25, 2007

AVISTA CORPORATION
(Exact name of registrant as specified in its charter)

Washington	**1-3701**	**91-0462470**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(I.R.S. Employer Identification No.)**

1411 East Mission Avenue, Spokane, Washington	**99202-2600**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: 509-489-0500
Web site: http://www.avistacorp.com

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 8 – Other Events

Item 8.01 Other Events.

Class Action Securities Litigation

On June 1, 2007, Avista Corporation (Avista Corp. or the Company) entered into a settlement agreement with respect to a class action lawsuit filed against Avista Corp., Thomas M. Matthews, the former Chairman of the Board, President and Chief Executive Officer of Avista Corp., Gary G. Ely, the current Chairman of the Board and Chief Executive Officer of Avista Corp., and Jon E. Eliassen, the former Senior Vice President and Chief Financial Officer of Avista Corp. The settlement agreement was filed in the United States District Court for the Eastern District of Washington (the Court) on June 4, 2007.

The lawsuit commenced with the filing of several class action complaints in the Court in September through November 2002. These complaints were subsequently consolidated and ultimately dismissed by the Court in October 2005. The order to dismiss was issued without prejudice, however, which allowed the plaintiffs to file an amended complaint. The amended class action complaint was filed on November 10, 2005 and asserted claims on behalf of all persons who purchased, converted, exchanged or otherwise acquired the Company's common stock during the period between November 23, 1999 and August 13, 2002. For further background information on this lawsuit see Note 12 of the Notes to Consolidated Financial Statements in Avista Corp.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2007.

The settlement agreement provides for certification of the plaintiff class and a full release by the class and dismissal with prejudice of all claims against Avista Corp. in consideration of payment of $9.5 million into a settlement fund. The settlement payment and litigation defense costs will be paid by Avista Corp.'s insurance company with the exception of the Company's $1 million self insured retention. The settlement agreement further provides that the individual defendants Mathews, Ely and Eliassen will be dismissed from the lawsuit.

The Company has vigorously contested this lawsuit since it commenced on September 27, 2002. It has denied, and continues to deny, in their entirety the allegations of wrongdoing in the lawsuit, including the allegations that Avista Corp. made any false or misleading statements in regard to the Company's business, business practices, risk management or trading activity. The Company denies that it engaged in any improper trading in the California energy market or in any other market, and it denies that the price of its stock was artificially inflated by reason of the misrepresentations and omissions alleged in the lawsuit. There have been no adverse determinations by any court against Avista Corp. or any of the defendants on the merits of the claims asserted by the plaintiffs in the lawsuit, and the Company denies that shareholders were harmed by the conduct alleged in the lawsuit. Neither the settlement agreement nor any of its terms or provisions, nor the Company's decision to settle the lawsuit, should be construed as an admission or concession of any kind of the merit or truth of any of the allegations of wrongdoing in the lawsuit, or of any fault, liability or wrongdoing whatsoever on the part of Avista Corp. The Company believes that throughout the class period alleged in the lawsuit it fully and adequately disclosed all material facts regarding the Company and made no misrepresentations of material facts regarding Avista Corp. The Company nonetheless considers it desirable to settle the lawsuit in order to avoid the cost and risks of further litigation and trial, and to dispose of burdensome and protracted litigation.

The settlement agreement must be approved by the Court before it will become effective. The Court's approval process has several steps. The settlement agreement is first presented to the Court for preliminary approval. If the Court grants preliminary approval of the settlement agreement, then there will follow a period in which plaintiffs' counsel give notice of and administer the settlement agreement. A fairness hearing will be held at which the Court will judge the fairness, reasonableness and adequacy of the settlement agreement, including payment of plaintiffs' and plaintiffs' counsel's fees and expenses, and at which any objections to the settlement agreement will be heard. If the Court then grants final approval of the settlement agreement, it will enter an order certifying the class and dismissing the claims in the lawsuit with prejudice. The Court's decision can be appealed. If the settlement agreement becomes effective, the settlement fund, less various costs of administration and plaintiffs' costs and attorneys' fees, will be distributed to class members who have filed an approved claim.

Update on Disposition of Avista Energy

On May 25, 2007, Avista Energy, Inc., a subsidiary of Avista Capital, Inc. and an indirect subsidiary of Avista Corp., received the final regulatory approval required to complete the sale of substantially all of its contracts and ongoing operations to Coral Energy Holding, L.P. (Coral Energy), a subsidiary of the Shell Group of Companies, as well as certain other subsidiaries of Coral Energy. Certain regulatory approvals were required from the Federal Energy Regulatory Commission and also from the Canadian government with respect to Canadian anti-competition laws.

For further information on this transaction see Note 3 of the Notes to Consolidated Financial Statements in Avista Corp.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2007.

With the receipt of all required regulatory approvals, the transaction is targeted to close at the end of the second quarter of 2007 subject to customary conditions including, but not limited to, release of all liens on the assets being acquired and the consents of parties to certain contracts to the assignment of those contracts.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

AVISTA CORPORATION
(Registrant)

Date: June 5, 2007

/s/ Marian M. Durkin
Marian M. Durkin
Senior Vice President, General Counsel
and Chief Compliance Officer

Form 10-Q

AVISTA CORP - ava

Filed: August 08, 2007 (period: June 30, 2007)

Quarterly report which provides a continuing view of a company's financial position

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington D.C. 20549

FORM 10-Q

(Mark One)
☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2007

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ______ to ______

Commission file number 1-3701

AVISTA CORPORATION
(Exact name of registrant as specified in its charter)

Washington **(State or other jurisdiction of incorporation or organization)**	**91-0462470** **(I.R.S. Employer Identification No.)**
1411 East Mission Avenue, Spokane, Washington **(Address of principal executive offices)**	**99202-2600** **(Zip Code)**

Registrant's telephone number, including area code: 509-489-0500
Web site: http://www.avistacorp.com

None
(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act): Yes ☐ No ☒

As of July 31, 2007, 52,828,118 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

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AVISTA CORPORATION

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FORWARD-LOOKING STATEMENTS

Our Quarterly Report on Form 10-Q contains forward-looking statements, which should be read with the cautionary statements and important factors included at "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Forward-Looking Statements" on pages 31-32. Forward-looking statements are all statements except those of historical fact, including, without limitation, those that are identified by the use of words that include "will," "may," "could," "should," "intends," "plans," "seeks," "anticipates," "estimates," "expects," "forecasts," "projects," "predicts," and similar expressions. All forward-looking statements are subject to a variety of risks and uncertainties and other factors. Many of these factors are beyond our control and could have a significant effect on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in our statements.

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CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

Avista Corporation

For the Three Months Ended June 30
Dollars in thousands, except per share amounts

	2007	2006
Operating Revenues:		
Utility revenues	$ 267,997	$ 258,076
Non-utility energy marketing and trading revenues	19,398	14,315
Other non-utility revenues	16,610	15,003
Total operating revenues	304,005	287,394
Operating Expenses:		
Utility operating expenses:		
Resource costs	135,520	122,086
Other operating expenses	50,191	48,218
Depreciation and amortization	21,298	20,111
Taxes other than income taxes	15,050	18,323
Non-utility operating expenses:		
Resource costs	18,386	18,196
Other operating expenses	22,172	16,569
Depreciation and amortization	1,170	1,313
Total operating expenses	263,787	244,816
Income from operations	40,218	42,578
Other Income (Expense):		
Interest expense	(20,234)	(22,209)
Interest expense to affiliated trusts	(1,817)	(1,765)
Capitalized interest	1,258	645
Other income-net	3,547	2,078
Total other income (expense)-net	(17,246)	(21,251)
Income before income taxes	22,972	21,327
Income taxes	8,789	7,868
Net income	$ 14,183	$ 13,459
Weighted-average common shares outstanding (thousands), basic	52,775	48,958
Weighted-average common shares outstanding (thousands), diluted	53,313	49,694
Total earnings per common share, basic (Note 11)	$ 0.27	$ 0.27
Total earnings per common share, diluted (Note 11)	$ 0.26	$ 0.27
Dividends paid per common share	$ 0.150	$ 0.140

The Accompanying Notes are an Integral Part of These Statements.

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CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

Avista Corporation

For the Six Months Ended June 30
Dollars in thousands, except per share amounts

	2007	2006
Operating Revenues:		
Utility revenues	$ 682,263	$ 681,366
Non-utility energy marketing and trading revenues	48,807	75,857
Other non-utility revenues	32,122	29,373
Total operating revenues	763,192	786,596
Operating Expenses:		
Utility operating expenses:		
Resource costs	405,506	393,691
Other operating expenses	99,232	93,945
Depreciation and amortization	42,388	41,091
Taxes other than income taxes	39,045	40,389
Non-utility operating expenses:		
Resource costs	56,113	68,323
Other operating expenses	39,308	32,880
Depreciation and amortization	2,445	2,761
Total operating expenses	684,037	673,080
Income from operations	79,155	113,516
Other Income (Expense):		
Interest expense	(40,607)	(44,354)
Interest expense to affiliated trusts	(3,627)	(3,469)
Capitalized interest	2,374	1,170
Other income-net	7,258	4,553
Total other income (expense)-net	(34,602)	(42,100)
Income before income taxes	44,553	71,416
Income taxes	16,276	26,385
Net income	$ 28,277	$ 45,031
Weighted-average common shares outstanding (thousands), basic	52,736	48,877
Weighted-average common shares outstanding (thousands), diluted	53,324	49,498
Total earnings per common share, basic (Note 11)	$ 0.54	$ 0.92
Total earnings per common share, diluted (Note 11)	$ 0.53	$ 0.91
Dividends paid per common share	$ 0.295	$ 0.280

The Accompanying Notes are an Integral Part of These Statements.

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CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

Avista Corporation

For the Three Months Ended June 30
Dollars in thousands

	2007	2006
Net income	$ 14,183	$ 13,459
Other Comprehensive Income (Loss):		
Foreign currency translation adjustment	896	428
Reclassification adjustment for foreign currency translation adjustment included in loss on sale of contracts	(2,379)	—
Unrealized gains on interest rate swap agreements - net of taxes of $1,606 and $1,419	2,983	2,635
Change in unfunded benefit obligation for pensions and other postretirement benefit plans, net of taxes of $29	53	—
Unrealized losses on derivative commodity instruments - net of taxes of $(997) and $(873)	(1,851)	(1,622)
Reclassification adjustment for realized gains on derivative commodity instruments included in net income - net of taxes of $(97) and $(156)	(180)	(289)
Reclassification adjustment for realized gains on derivative commodity instruments included in loss on sale of contracts, net of taxes of $464	862	—
Unrealized investment losses - net of taxes of $(11)	—	(21)
Total other comprehensive income	384	1,131
Comprehensive income	$ 14,567	$ 14,590

For the Six Months Ended June 30
Dollars in thousands

	2007	2006
Net income	$ 28,277	$ 45,031
Other Comprehensive Income (Loss):		
Foreign currency translation adjustment	1,010	410
Reclassification adjustment for foreign currency translation adjustment included in loss on sale of contracts	(2,379)	—
Unrealized gains on interest rate swap agreements - net of taxes of $1,634 and $3,466	3,035	6,436
Change in unfunded benefit obligation for pensions and other postretirement benefit plans, net of taxes of $156	289	—
Unrealized gains (losses) on derivative commodity instruments - net of taxes of $(324) and $230	(602)	427
Reclassification adjustment for realized gains on derivative commodity instruments included in net income - net of taxes of $(136) and $(491)	(253)	(912)
Reclassification adjustment for realized gains on derivative commodity instruments included in loss on sale of contracts, net of taxes of $464	862	—
Unrealized investment losses - net of taxes of $(9)	—	(17)
Total other comprehensive income	1,962	6,344
Comprehensive income	$ 30,239	$ 51,375

The Accompanying Notes are an Integral Part of These Statements.

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CONSOLIDATED BALANCE SHEETS
(Unaudited)

Avista Corporation

Dollars in thousands

	June 30, 2007	December 31, 2006 (as restated see Note 14)
Assets:		
Current Assets:		
Cash and cash equivalents	$ 103,302	$ 28,242
Restricted cash	3,621	29,903
Accounts and notes receivable-less allowances of $42,418 and $42,360	187,639	286,150
Energy commodity derivative assets	—	343,726
Utility energy commodity derivative assets	10,410	10,828
Regulatory asset for utility derivatives	17,977	62,650
Funds held for customers	89,752	90,134
Deposits with counterparties	31,064	79,477
Materials and supplies, fuel stock and natural gas stored	29,437	42,425
Deferred income taxes	20,479	10,932
Other current assets	67,508	47,807
Total current assets	561,189	1,032,274
Net Utility Property:		
Utility plant in service	2,990,655	2,938,456
Construction work in progress	133,033	103,226
Total	3,123,688	3,041,682
Less: Accumulated depreciation and amortization	856,070	826,645
Total net utility property	2,267,618	2,215,037
Other Property and Investments:		
Investment in exchange power-net	29,808	31,033
Non-utility properties and investments-net	57,505	60,301
Non-current energy commodity derivative assets	—	313,300
Investment in affiliated trusts	13,403	13,403
Other property and investments-net	18,460	15,594
Total other property and investments	119,176	433,631
Deferred Charges:		
Regulatory assets for deferred income taxes	103,363	105,935
Regulatory assets for pensions and other postretirement benefits	52,814	54,192
Other regulatory assets	34,518	31,752
Non-current utility energy commodity derivative assets	31,960	25,575
Power and natural gas deferrals	77,025	97,792
Unamortized debt expense	43,275	46,554
Other deferred charges	14,192	13,766
Total deferred charges	357,147	375,566
Total assets	$ 3,305,130	$ 4,056,508

The Accompanying Notes are an Integral Part of These Statements.

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CONSOLIDATED BALANCE SHEETS (continued)
(Unaudited)

Avista Corporation

Dollars in thousands

	June 30, 2007	December 31, 2006 (as restated see Note 14)
Liabilities and Stockholders' Equity:		
Current Liabilities:		
Accounts payable	$ 179,589	$ 286,099
Energy commodity derivative liabilities	—	313,499
Customer fund obligations	89,752	90,134
Deposits from counterparties	50,110	41,493
Current portion of long-term debt	307,720	26,605
Current portion of preferred stock-cumulative	26,250	26,250
Short-term borrowings	16,000	4,000
Interest accrued	15,455	11,595
Utility energy commodity derivative liabilities	28,387	73,478
Other current liabilities	71,088	72,056
Total current liabilities	784,351	945,209
Long-term debt	655,377	949,854
Long-term debt to affiliated trusts	113,403	113,403
Other Non-Current Liabilities and Deferred Credits:		
Non-current energy commodity derivative liabilities	—	309,990
Regulatory liability for utility plant retirement costs	203,242	197,712
Non-current regulatory liability for utility derivatives	27,961	15,400
Pensions and other postretirement benefits	99,120	103,604
Deferred income taxes	425,199	459,756
Other non-current liabilities and deferred credits	69,887	47,055
Total other non-current liabilities and deferred credits	825,409	1,133,517
Total liabilities	2,378,540	3,141,983
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Stockholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 52,826,120 and 52,514,326 shares outstanding	720,349	715,620
Accumulated other comprehensive loss	(15,854)	(17,816)
Retained earnings	222,095	216,721
Total stockholders' equity	926,590	914,525
Total liabilities and stockholders' equity	$ 3,305,130	$ 4,056,508

The Accompanying Notes are an Integral Part of These Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

Avista Corporation

For the Six Months Ended June 30
Dollars in thousands

	2007	2006
Operating Activities:		
Net income	$ 28,277	$ 45,031
Non-cash items included in net income:		
Depreciation and amortization	44,833	43,852
Benefit for deferred income taxes	(17,143)	(16,469)
Power and natural gas cost amortizations, net of deferrals	23,591	41,369
Amortization of debt expense	3,263	3,847
Unrealized loss on energy commodity derivatives	24,594	9,938
Other	773	(8,390)
Changes in working capital components:		
Accounts and notes receivable	98,453	292,355
Materials and supplies, fuel stock and natural gas stored	(8,280)	(4,266)
Deposits with counterparties	48,413	(11,658)
Other current assets	2,060	(42,098)
Accounts payable	(101,949)	(276,927)
Deposits from counterparties	8,617	39,489
Other current liabilities	2,510	45,874
Net cash provided by operating activities	158,012	161,947
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(92,626)	(73,278)
Proceeds from sale of utility property claim	—	5,484
Other capital expenditures	(1,989)	(1,523)
Decrease (increase) in restricted cash	26,282	(14,506)
Changes in other property and investments	(2,863)	(2,078)
Proceeds from property sales	215	7,709
Net cash used in investing activities	(70,981)	(78,192)
Financing Activities:		
Increase (decrease) in short-term borrowings	12,000	(56,494)
Redemption and maturity of long-term debt	(12,290)	(7,639)
Premiums paid for the redemption of long-term debt	—	(355)
Cash dividends paid	(15,577)	(13,661)
Issuance of common stock	3,354	4,973
Other	542	(647)
Net cash used in financing activities	(11,971)	(73,823)
Net increase in cash and cash equivalents	75,060	9,932
Cash and cash equivalents at beginning of period	28,242	25,917
Cash and cash equivalents at end of period	$ 103,302	$ 35,849
Supplemental Cash Flow Information:		
Cash paid during the period:		
Interest	$ 37,111	$ 46,072
Income taxes	28,742	36,944
Non-cash financing and investing activities:		
Liability to subsidiary minority shareholders	11,567	—

The Accompanying Notes are an Integral Part of These Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The accompanying consolidated financial statements of Avista Corporation (Avista Corp. or the Company) for the interim periods ended June 30, 2007 and 2006 are unaudited; however, in the opinion of management, the statements reflect all adjustments necessary for a fair statement of the results for the interim periods. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. The Consolidated Statements of Income for the interim periods are not necessarily indicative of the results to be expected for the full year. These consolidated financial statements do not contain the detail or footnote disclosure concerning accounting policies and other matters which would be included in full fiscal year consolidated financial statements; therefore, they should be read in conjunction with the Company's audited consolidated financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2006 (2006 Form 10-K). Please refer to the section "Acronyms and Terms" in the 2006 Form 10-K for definitions of terms such as capacity, energy and therm.

The Company has restated its Consolidated Balance Sheet as of December 31, 2006 for immaterial adjustments as described in Note 14.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corp. is an energy company engaged in the generation, transmission and distribution of energy as well as other energy-related businesses. Avista Utilities is an operating division of Avista Corp., comprising the regulated utility operations. Avista Utilities generates, transmits and distributes electricity in parts of eastern Washington and northern Idaho. In addition, Avista Utilities has electric generating facilities in western Montana and northern Oregon. Avista Utilities also provides natural gas distribution service in parts of eastern Washington and northern Idaho, as well as parts of northeast and southwest Oregon. Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility business segments, including Avista Energy, Inc. (Avista Energy) and Advantage IQ, Inc. (Advantage IQ). Avista Energy was an electricity and natural gas marketing, trading and resource management business. On June 30, 2007, Avista Energy completed the sale of substantially all of its contracts and ongoing operations. See Note 3 for further information. Advantage IQ is a provider of facility information and cost management services for multi-site customers throughout North America. See Note 15 for business segment information.

The Company's operations are exposed to risks including, but not limited to:

- market prices and supply of wholesale energy, which the Company purchases and sells, including power, fuel and natural gas,
- regulatory allowance of the recovery of power and natural gas costs, operating costs and capital investments,
- streamflow and weather conditions,
- the effects of changes in legislative and governmental regulations, including restrictions on emissions from generating plants and requirements for the acquisition of new resources,
- changes in regulatory requirements,
- availability of generation facilities,
- competition,
- technology, and
- availability of funding.

Also, like other utilities, the Company's facilities and operations are exposed to terrorism risks or other malicious acts. In addition, the energy business exposes the Company to the financial, liquidity, credit and price risks associated with wholesale purchases and sales of energy commodities.

Basis of Reporting

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries, including variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. All significant intercompany balances have been eliminated in consolidation. The accompanying financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants.

Other Income-Net

Other income-net consisted of the following items for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Interest income	$ 3,911	$ 2,279	$ 6,386	$ 4,183
Interest on power and natural gas deferrals	1,026	1,588	2,228	3,494
Net gain (loss) on investments	1	43	445	(390)
Other expense	(2,375)	(2,512)	(3,786)	(3,964)
Other income	984	680	1,985	1,230
Total	$ 3,547	$ 2,078	$ 7,258	$ 4,553

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss), net of tax, consisted of the following as of June 30, 2007 and December 31, 2006 (dollars in thousands):

	June 30, 2007	December 31, 2006
Foreign currency translation adjustment	$ —	$ 1,369
Unfunded benefit obligation for pensions and other postretirement benefit plans	(15,543)	(15,832)
Unrealized loss on interest rate swap agreements	(311)	(3,346)
Unrealized loss on derivative commodity instruments	—	(7)
Total accumulated other comprehensive loss	$ (15,854)	$ (17,816)

Assets Held for Sale

Assets held for sale are recorded at the lower of their carrying amount or fair value less cost to sell. As of June 30, 2007 and December 31, 2006, assets held for sale of $3.5 million primarily included turbines and related equipment at Avista Utilities, which is included in other current assets on the Consolidated Balance Sheets. There were not any liabilities held for sale as of June 30, 2007 and December 31, 2006. See Note 3 regarding the sale of substantially all of the contracts and ongoing operations of Avista Energy on June 30, 2007.

Regulatory Deferred Charges and Credits

The Company prepares its consolidated financial statements in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." The Company prepares its financial statements in accordance with SFAS No. 71 because:

- rates for regulated services are established by or subject to approval by an independent third-party regulator,
- the regulated rates are designed to recover the cost of providing the regulated services, and
- in view of demand for the regulated services and the level of competition, it is reasonable to assume that rates can be charged to and collected from customers at levels that will recover costs.

SFAS No. 71 requires the Company to reflect the impact of regulatory decisions in its financial statements. SFAS No. 71 requires that certain costs and/or obligations (such as incurred power and natural gas costs not currently recovered through rates, but expected to be recovered in the future) are reflected as deferred charges or credits on the Consolidated Balance Sheets. These costs and/or obligations are not reflected in the statement of income until the period during which matching revenues are recognized.

If at some point in the future the Company determines that it no longer meets the criteria for continued application of SFAS No. 71 for all or a portion of its regulated operations, the Company could be:

- required to write off its regulatory assets, and
- precluded from the future deferral of costs not recovered through rates at the time such costs are incurred, even if the Company expected to recover such costs in the future.

The Company's primary regulatory assets include:

- power and natural gas deferrals,
- investment in exchange power,
- regulatory asset for deferred income taxes,
- unamortized debt expense,
- assets offsetting net utility energy commodity derivative liabilities (see Note 5 for further information),
- demand side management programs,

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- conservation programs, and
- unfunded pensions and other postretirement benefits.

Those items without a specific line on the Consolidated Balance Sheets are included in other regulatory assets.

Regulatory liabilities include:

- utility plant retirement costs,
- liabilities created when the Centralia Power Plant was sold,
- liabilities offsetting net utility energy commodity derivative assets (see Note 5 for further information), and
- the gain on the general office building sale/leaseback.

Those items without a specific line on the Consolidated Balance Sheets are included in other current liabilities and other non-current liabilities and deferred credits.

NOTE 2. NEW ACCOUNTING STANDARDS

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109," (FIN 48) which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires the evaluation of a tax position as a two-step process. First, the Company is required to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If the tax position meets the "more likely than not" recognition threshold, it is then measured and recorded at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. The Company adopted FIN 48 in the first quarter of 2007 (effective January 1, 2007). The adoption of FIN 48 did not have a cumulative effect on the Company's financial statements. See Note 8 for further information.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which provides enhanced guidance for using fair value to measure assets and liabilities. This statement also expands disclosures about fair value measurements. This statement applies under other accounting pronouncements that require or permit fair value measurements. However, the statement does not require any new fair value measurements. This statement emphasizes that fair value is a market-based measurement and not an entity-specific measurement. Therefore a fair value measurement should be determined based on the assumptions that market participants would use in pricing an asset or liability. The statement establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data. The Company will be required to adopt SFAS No. 157 in 2008. The Company is evaluating the impact SFAS No. 157 will have on its financial condition and results of operations.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." This statement permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected would be reported in net income. The Company will be required to adopt SFAS No. 159 in 2008. The Company is evaluating the impact SFAS No. 159 will have on its financial condition and results of operations.

NOTE 3. DISPOSITION OF AVISTA ENERGY

On June 30, 2007, Avista Energy and Avista Energy Canada, Ltd. (Avista Energy Canada) completed the sale of substantially all of their contracts and ongoing operations to Coral Energy Holding, L.P. (Coral Energy), a subsidiary of the Shell Group of Companies, as well as to certain other subsidiaries of Coral Energy.

The transaction was completed through the purchase and sale agreement and certain other ancillary agreements. As consideration for the assets acquired (net of liabilities assumed), the purchase price paid by Coral Energy was calculated on the closing date as the sum of the following:

- the net trade book value of contracts acquired,
- the market value of the natural gas inventory, and
- the net book value of the tangible fixed assets acquired.

Proceeds from the transaction included cash consideration for the net assets acquired by Coral Energy and the liquidation of the remaining net current assets of Avista Energy not sold to Coral Energy (primarily receivables, restricted cash and deposits with counterparties, the majority of which will be liquidated within 60 days). On July 2, 2007, Avista Energy received $34.4 million from Coral Energy based on the value of the net assets sold as of May 31, 2007. This amount was adjusted and Avista Energy paid Coral Energy $4.5 million on August 2, 2007 based on the determination of final market values and other closing adjustments as of June 30, 2007. The pre-tax net loss on the transaction was $4.2 million, which is included in non-utility other operating expenses in the Consolidated Statements of Income for the three and six months ended June 30, 2007. The net loss on the transaction increased from March 31, 2007 primarily due to a decrease in the market value of natural gas inventory and changes in the value of certain hedging contracts.

In addition to the cash proceeds received from Coral Energy, Avista Energy has liquidated substantially all of its remaining net current assets through July 31, 2007. Over time, Avista Corp. plans to redeploy into its regulated utility operations the majority of the approximate $170 million of total proceeds either received from Coral Energy or realized from the liquidation of the remaining net current assets of Avista Energy.

Assets and liabilities excluded from the sale and retained or liquidated by Avista Energy include:

- cash,
- certain agreements, including electric transmission, natural gas transportation and a power purchase agreement, related to a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho (Lancaster Plant), for periods after December 31, 2009 through 2026,
- storage rights at a natural gas facility located in Washington (Jackson Prairie) for periods after April 30, 2011,
- accounts receivable,
- certain software, hardware, licenses and permits,
- accounts payable,
- tax obligations,
- cash deposits with and from counterparties,
- litigation matters (including matters related to western energy markets), and
- certain employment agreements and employee related obligations.

Certain assets of Avista Energy with a net book value of approximately $25 million will not be liquidated within 60 days. These primarily include natural gas storage and deferred tax assets. The Company expects that the natural gas storage will ultimately be transferred to Avista Utilities, subject to future regulatory approval by the Washington Utilities and Transportation Commission (WUTC) and the Idaho Public Utilities Commission (IPUC). The Company also expects that the power purchase agreement for the Lancaster Plant for the period 2010 through 2026 will be transferred to Avista Utilities, subject to future regulatory approval.

In connection with the transaction, on June 30, 2007, Avista Energy and its affiliates entered into an Indemnification Agreement with Coral Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Coral Energy each agree to provide indemnification of the other and the other’s affiliates for certain events arising out of and matters described in the purchase and sale agreement entered into on April 16, 2007 and certain other transaction agreements. In general, such indemnification is not required unless and until a party’s claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy’s obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of $30 million plus certain fees and expenses. Avista Capital has granted Coral Energy a security interest in 50 percent of Avista Capital’s common shares of Advantage IQ as collateral for its Guaranty. The aggregate obligations secured by this security interest will in no event exceed $25 million. Avista Capital may substitute collateral, such as cash or letters of credit, in place of the security interest in Advantage IQ’s common shares. This security interest in Advantage IQ’s common shares will terminate in 18 months (December 31, 2008) except to the extent of claims actually made prior to expiration of the 18-month period. The Guaranty will terminate April 30, 2011 except with respect to claims made prior to termination.

Avista Energy has made customary representations, warranties and covenants in the purchase and sale agreement. Avista Corp. and its subsidiaries have agreed that for a period of 60 calendar months beginning on the closing of the transaction (June 30, 2007), neither Avista Corp. nor any of its subsidiaries will form or participate through ownership or any alliance, or internally, develop capabilities to replicate the business activities of Avista Energy within the region of the Western Electric Coordinating Council. This restriction has certain exceptions primarily related to any assets or contracts retained by Avista Energy and any current corporate activities outside of Avista Energy, including any resource optimization or associated trading or hedging activities of the character currently being conducted by Avista Utilities, an operating division of Avista Corp., in the ordinary course of its regulated utility business (see Notes 5 and 6).

NOTE 4. ACCOUNTS RECEIVABLE SALE

Avista Receivables Corporation (ARC) is a wholly owned, bankruptcy-remote subsidiary of Avista Corp., formed for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. On March 19, 2007, Avista Corp., ARC and a third-party financial institution amended a Receivables Purchase Agreement. The most significant amendment was to extend the termination date from March 20, 2007 to March 17, 2008. Under the Receivables Purchase Agreement, ARC can sell without recourse, on a revolving basis, up to $85.0 million of those receivables. ARC is obligated to pay fees that approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. On a consolidated basis, the amount of such fees is included in other operating expenses of Avista Corp. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of Avista Corp.'s $320.0 million committed line of credit (see Note 9). As of June 30, 2007, $66.0 million in accounts receivables were sold under this revolving agreement, a decrease from $85.0 million as of December 31, 2006.

NOTE 5. UTILITY ENERGY COMMODITY DERIVATIVE ASSETS AND LIABILITIES

SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It requires the recording of all derivatives as either assets or liabilities on the balance sheet measured at estimated fair value and the recognition of the unrealized gains and losses. In certain defined conditions, a derivative may be specifically designated as a hedge for a particular exposure. The accounting for derivatives depends on the intended use of the derivatives and the resulting designation.

Avista Utilities enters into forward contracts to purchase or sell electricity and natural gas. Under these forward contracts, Avista Utilities commits to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. Certain of these forward contracts are considered derivative instruments. Avista Utilities also records derivative commodity assets and liabilities for over-the-counter and exchange-traded derivative instruments as well as certain long-term contracts. These contracts are entered into as part of Avista Utilities' management of its loads and resources as discussed in Note 6. In conjunction with the issuance of SFAS No. 133, the WUTC and the IPUC issued accounting orders authorizing Avista Utilities to offset any derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The orders provide for Avista Utilities to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Consolidated Statements of Income. Realized gains and losses are recognized in the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the Energy Recovery Mechanism in Washington and the Power Cost Adjustment mechanism in Idaho.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as assets or liabilities at estimated fair value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives under SFAS No. 133 are generally accounted for at cost until they are settled or realized, unless there is a decline in the fair value of the contract that is determined to be other than temporary.

Utility energy commodity derivatives consisted of the following as of June 30, 2007 and December 31, 2006 (dollars in thousands):

	June 30, 2007	December 31, 2006
Current utility energy commodity derivative assets	$ 10,410	$ 10,828
Current utility energy commodity derivative liabilities	(28,387)	(73,478)
Net current regulatory asset	$ (17,977)	$ (62,650)
Non-current utility energy commodity derivative assets	$ 31,960	$ 25,575
Non-current utility energy commodity derivative liabilities	(3,999)	(10,175)
Net non-current regulatory liability	$ 27,961	$ 15,400

Non-current utility energy commodity derivative liabilities are included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets.

NOTE 6. ENERGY COMMODITY TRADING

The Company's energy-related businesses are exposed to risks relating to, but not limited to:

- changes in certain commodity prices,
- interest rates,
- foreign currency, and
- counterparty performance.

Avista Utilities utilizes derivative instruments, such as forwards, futures, swaps and options in order to manage the various risks relating to these exposures, and Avista Energy engaged in the trading of such instruments. The Company uses a variety of techniques to manage risks for their energy resources and wholesale energy market activities. The Company has risk management policies and procedures to manage these risks, both qualitative and quantitative. The Company's Risk Management Committee establishes the Company's risk management policies and procedures and monitors compliance. The Risk Management Committee is comprised of certain Company officers and other individuals and is overseen by the Audit Committee of the Company's Board of Directors.

Avista Utilities

Avista Utilities engages in an ongoing process of resource optimization, which involves the economic selection from available resources to serve Avista Utilities' load obligations and uses its existing resources to capture available economic value. Avista Utilities sells and purchases wholesale electric capacity and energy and fuel as part of the process of acquiring resources to serve its load obligations. These transactions range from terms of one hour up to multiple years. Avista Utilities makes continuing projections of:

- loads at various points in time (ranging from one hour to multiple years) based on, among other things, estimates of factors such as customer usage and weather, as well as historical data and contract terms, and
- resource availability at these points in time based on, among other things, estimates of streamflows, availability of generating units, historic and forward market information and experience.

On the basis of these projections, Avista Utilities makes purchases and sales of energy to match expected resources to expected electric load requirements. Resource optimization involves generating plant dispatch and scheduling available resources and also includes transactions such as:

- purchasing fuel for generation,
- when economic, selling fuel and substituting wholesale purchases for the operation of Avista Utilities' resources, and
- other wholesale transactions to capture the value of generation and transmission resources.

Avista Utilities' optimization process includes entering into hedging transactions to manage risks.

As part of its resource optimization process described above, Avista Utilities manages the impact of fluctuations in electric energy prices by measuring and controlling the volume of energy imbalance between projected loads and resources and through the use of derivative commodity instruments for hedging purposes. Load/resource imbalances within a rolling 18-month planning horizon are compared against established volumetric guidelines and management determines the timing and specific actions to manage the imbalances. Management also assesses available resource decisions and actions that are appropriate for longer-term planning periods.

Avista Energy

As disclosed in Note 3, on June 30, 2007, Avista Energy and Avista Energy Canada sold substantially all of their contracts and ongoing operations. Avista Energy's results of operations are reflected in Avista Corp's consolidated financial statements for the three and six months ended June 30, 2007.

Avista Energy implemented hedge accounting in accordance with SFAS No. 133. Specific natural gas and electric trading derivative contracts were designated as hedging instruments in cash flow hedging relationships. With the completion of the sale of substantially all contracts on June 30, 2007, hedge accounting at Avista Energy was terminated and the balance of accumulated other comprehensive loss was reclassified to earnings as part of the loss on the transaction.

The change in the estimated fair value position of Avista Energy's energy commodity portfolio, net of reserves for credit and market risk for the six months ended June 30, 2007 (prior to the sale) was an unrealized loss of $24.6 million and is included in the Consolidated Statements of Income in non-utility energy marketing and trading revenues. The change in the fair value position for the six months ended June 30, 2006 was an unrealized loss of $9.9 million.

NOTE 7. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering substantially all regular full-time employees at Avista Utilities and Avista Energy. Individual benefits under this plan are based upon the employee's years of service and average compensation as specified in the plan. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company made $15 million in cash contributions to the pension plan in 2006 and expects to contribute $15 million to the pension plan in 2007.

The Company also has a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to executive officers of the Company. The SERP is intended to provide benefits to executive officers whose benefits under the pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans.

The Company provides certain health care and life insurance benefits for substantially all of its retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services.

The Company established a Health Reimbursement Arrangement to provide employees with tax-advantaged funds to pay for allowable medical expenses upon retirement. The amount earned by the employee is fixed on the retirement date based on employee's years of service and the ending salary. The liability and expense of this plan are included as other postretirement benefits.

The Company provides death benefits to beneficiaries of executive officers who die during their term of office or after retirement. The liability and expense for this plan are included as other postretirement benefits. As disclosed in Note 14, the Company has restated prior financial statements to recognize the liability and costs of this plan.

The Company uses a December 31 measurement date for its pension and postretirement plans. The following table sets forth the components of net periodic benefit costs for the three and six months ended June 30 (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
Three months ended June 30:				
Service cost	$ 2,740	$ 2,495	$ 184	$ 175
Interest cost	4,766	4,231	541	416
Expected return on plan assets	(4,802)	(4,236)	(391)	(342)
Transition obligation recognition	—	—	126	126
Amortization of prior service cost	164	164	—	—
Net loss recognition	774	895	55	86
Net periodic benefit cost	$ 3,642	$ 3,549	$ 515	$ 461
Six months ended June 30:				
Service cost	$ 5,480	$ 4,990	$ 320	$ 350
Interest cost	9,532	8,463	980	832
Expected return on plan assets	(9,604)	(8,472)	(782)	(684)
Transition obligation recognition	—	—	252	253
Amortization of prior service cost	328	327	—	—
Net loss recognition	1,543	1,742	112	171
Net periodic benefit cost	$ 7,279	$ 7,050	$ 882	$ 922

NOTE 8. ACCOUNTING FOR INCOME TAXES

As disclosed in Note 2, the Company adopted FIN 48 effective January 1, 2007, which did not have a cumulative effect on the Company's financial statements.

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon, Montana and California. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The Internal Revenue Service (IRS) has examined the Company's 2001, 2002 and 2003 federal income tax returns. Despite those tax years still remaining open, all issues have been resolved with the exception of the timing for the deductions of certain indirect overhead costs. The IRS is currently conducting an examination of the Company's 2004 and 2005 federal income tax returns. This examination could result in a change in the liability for uncertain tax positions. However, an estimate of the range of any such possible change cannot be made at this time. The Company does not believe that any open tax years with respect to state income taxes could result in any adjustments that would be significant to the consolidated financial statements.

In August 2005, the Treasury Department issued regulations and the IRS issued a revenue ruling that affects the tax treatment by Avista Corp. of certain indirect overhead expenses. Avista Corp. had previously made a tax election to currently deduct certain indirect overhead costs, starting with the 2002 tax return, that were capitalized for financial accounting purposes. This election allowed Avista Corp. to take tax deductions resulting in a total reduction of approximately $40 million in current tax liabilities for 2002, 2003 and 2004. These current tax benefits were deferred on the balance sheet in accordance with the provisions of SFAS No. 109 and did not affect net income.

Due to the revenue ruling and related regulations, the IRS has disallowed the tax deduction of indirect overhead expenses during their examination of the Company's 2001, 2002 and 2003 federal income tax returns. The Company believes that the tax deductions claimed on tax returns were appropriate based on the applicable statutes and regulations in effect at the time. Avista Corp. appealed the proposed IRS adjustment on April 19, 2006. The Company's appeal has been received and has been scheduled for review by the IRS Appeals Division starting later in 2007. The Company repaid a portion of the previous tax deductions through tax payments in 2005 and 2006. There can be no assurance that the Company's position will prevail. However, it is not expected to have a significant effect on the Company's net income.

The Company estimates that its liability for unrecognized tax benefits is $22.6 million at each of January 1, 2007 and June 30, 2007. With the adoption of FIN 48, this amount was reclassified from deferred income taxes to liability for unrecognized tax benefits. This liability primarily relates to the indirect overhead expenses described above, and the amount of this liability is included as other non-current liabilities and deferred credits on the Consolidated Balance Sheet as of June 30, 2007. The liability for unrecognized tax benefits would not affect the tax rate if recognized in 2007, as any adjustment to this tax item would be offset by an adjustment to current income tax expense. The liability for interest expense for unrecognized tax benefits as of January 1, 2007 was not material due to net operating loss and tax credit carryovers. The change in the liability for interest expense during the six months ended June 30, 2007 was not material. The Company has not accrued any penalties. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operating expense.

NOTE 9. SHORT-TERM BORROWINGS

The Company has a committed line of credit agreement with various banks in the total amount of $320.0 million with an expiration date of April 5, 2011. Under the credit agreement, the Company can request the issuance of up to $320.0 million in letters of credit. The Company had $16.0 million of borrowings outstanding as of June 30, 2007 and $4.0 million of borrowings outstanding as of December 31, 2006. Total letters of credit outstanding were $44.3 million as of June 30, 2007 and $77.1 million as of December 31, 2006. The committed line of credit is secured by $320.0 million of non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions, including a covenant requiring the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Utilities for the preceding twelve-month period at the end of any fiscal quarter to be greater than 1.6 to 1. As of June 30, 2007, the Company was in compliance with this covenant with a ratio of 2.50 to 1. The committed line of credit agreement also has a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 70 percent at the end of any fiscal quarter. This ratio limitation will be increased to 75 percent during the period between the completion of the proposed change in the Company's corporate organization (see Note 13) and December 31, 2007. As of June 30, 2007, the Company was in compliance with this covenant with a ratio of 53.4 percent. If the proposed change in organization becomes effective, the committed line of credit agreement will remain at Avista Corp.

On June 30, 2007, Avista Energy and Avista Energy Canada, as co-borrowers, terminated a committed credit agreement with a group of banks in the aggregate amount of $145.0 million that had an expiration date of July 12, 2007. The credit agreement was terminated in connection with the closing of the sale of substantially all of the contracts and ongoing operations of Avista Energy and Avista Energy Canada as described at Note 3. There were not any early termination penalties incurred by Avista Energy or Avista Energy Canada.

NOTE 10. LONG-TERM DEBT

The following details the interest rate and maturity dates of long-term debt outstanding as of June 30, 2007 and December 31, 2006 (dollars in thousands):

Maturity Year	Description	Interest Rate	June 30, 2007	December 31, 2006
2007	Secured Medium-Term Notes	5.99%	$ 13,850	$ 13,850
2008	Secured Medium-Term Notes	6.06%-6.95%	45,000	45,000
2010	Secured Medium-Term Notes	6.67%-8.02%	35,000	35,000
2012	Secured Medium-Term Notes	7.37%	7,000	7,000
2013	First Mortgage Bonds	6.13%	45,000	45,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Pollution Control Bonds	5.00%	66,700	66,700
2034	Pollution Control Bonds	5.13%	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
	Total secured long-term debt		680,550	680,550
2007	Unsecured Medium-Term Notes	7.90%-7.94%	—	12,000
2008	Unsecured Senior Notes	9.75%	272,860	272,860
2023	Pollution Control Bonds	6.00%	4,100	4,100
	Total unsecured long-term debt		276,960	288,960
	Other long-term debt and capital leases		5,789	7,364
	Interest rate swaps		1,064	1,037
	Unamortized debt discount		(1,266)	(1,452)
	Total		963,097	976,459
	Current portion of long-term debt		(307,720)	(26,605)
	Total long-term debt		$ 655,377	$ 949,854

NOTE 11. EARNINGS PER COMMON SHARE

The following table presents the computation of basic and diluted earnings per common share for the three and six months ended June 30 (in thousands, except per share amounts):

	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Numerator:				
Net income	$ 14,183	$ 13,459	$ 28,277	$ 45,031
Subsidiary earnings adjustment for dilutive securities	(118)	—	(208)	—
Adjusted net income for computation of diluted earnings per common share	$ 14,065	$ 13,459	$ 28,069	$ 45,031
Denominator:				
Weighted-average number of common shares outstanding-basic	52,775	48,958	52,736	48,877
Effect of dilutive securities:				
Contingent stock awards	214	388	244	300
Stock options	324	348	344	321
Weighted-average number of common shares outstanding-diluted	53,313	49,694	53,324	49,498
Total earnings per common share, basic	$ 0.27	$ 0.27	$ 0.54	$ 0.92
Total earnings per common share, diluted	$ 0.26	$ 0.27	$ 0.53	$ 0.91

Total stock options outstanding that were not included in the calculation of diluted earnings per common share were 20,200 for the three and six months ended June 30, 2007 and 393,900 for the three and six months ended June 30, 2006. These stock options were excluded from the calculation because they were antidilutive based on the fact that the exercise price of the stock options was higher than the average market price of Avista Corp. common stock during the respective period.

NOTE 12. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. With respect to these proceedings, the Company intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. With respect to matters that affect Avista Utilities' operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the rate making process. With respect to matters discussed in this Note that affect Avista Energy (particularly the California Refund Proceeding), any potential liabilities or refunds remain at Avista Corp. and/or its subsidiaries and have not been assumed by Coral Energy and/or its affiliates.

Federal Energy Regulatory Commission Inquiry

On April 19, 2004, the FERC issued an order approving the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) reached by Avista Corp. doing business as Avista Utilities, Avista Energy and the FERC's Trial Staff with respect to an investigation into the activities of Avista Utilities and Avista Energy in western energy markets during 2000 and 2001. In the Agreement in Resolution, the FERC Trial Staff stated that its investigation found: (1) no evidence that any executives or employees of Avista Utilities or Avista Energy knowingly engaged in or facilitated any improper trading strategy; (2) no evidence that Avista Utilities or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; and (3) that Avista Utilities and Avista Energy did not withhold relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001. In April 2005 and June 2005, the California Parties and the City of Tacoma, respectively, filed petitions for review of the FERC's decisions approving the Agreement in Resolution with the United States Court of Appeals for the Ninth Circuit. Based on the FERC's order approving the Agreement in Resolution and the FERC's denial of rehearing requests, the Company does not expect that this proceeding will have any material adverse effect on its financial condition, results of operations or cash flows.

Class Action Securities Litigation

On June 1, 2007, Avista Corp. entered into a settlement agreement with respect to a class action lawsuit filed against Avista Corp., Thomas M. Matthews, the former Chairman of the Board, President and Chief Executive Officer of Avista Corp., Gary G. Ely, the current Chairman of the Board and Chief Executive Officer of Avista Corp., and Jon E. Eliassen, the former Senior Vice President and Chief Financial Officer of Avista Corp. The settlement agreement was filed in the United States District Court for the Eastern District of Washington (the Court) on June 4, 2007.

The lawsuit commenced with the filing of several class action complaints in the Court in September through November 2002. These complaints were subsequently consolidated and ultimately dismissed by the Court in October 2005. The order to dismiss was issued without prejudice, however, which allowed the plaintiffs to file an amended complaint. The amended class action complaint was filed on November 10, 2005 and asserted claims on behalf of all persons who purchased, converted, exchanged or otherwise acquired the Company's common stock during the period between November 23, 1999 and August 13, 2002.

The settlement agreement provides for certification of the plaintiff class and a full release by the class and dismissal with prejudice of all claims against Avista Corp. in consideration of payment of $9.5 million into a settlement fund. The settlement payment and litigation defense costs will be paid by Avista Corp.'s insurance company with the exception of the Company's $1 million self-insured retention. The settlement agreement further provides that the individual defendants Matthews, Ely and Eliassen will be dismissed from the lawsuit.

The Company has vigorously contested this lawsuit since it commenced on September 27, 2002. The Company has denied, and continues to deny in their entirety, the allegations of wrongdoing in the lawsuit, including the allegations that Avista Corp. made any false or misleading statements with regard to the Company's business, business practices, risk management or trading activity. The Company denies that it engaged in any improper trading in the California energy market or in any other market, and it denies that the price of its stock was artificially inflated by reason of the misrepresentations and omissions alleged in the lawsuit. There have been no adverse determinations by any court against Avista Corp. or any of the defendants on the merits of the claims asserted by the plaintiffs in the lawsuit, and the Company denies that shareholders were harmed by the conduct alleged in the lawsuit. Neither the settlement agreement nor any of its terms or provisions, nor the Company's decision to settle the lawsuit, should be construed as an admission or concession of any kind of the merit or truth of any of the allegations of wrongdoing in the lawsuit, or of any fault, liability or wrongdoing whatsoever on the part of Avista Corp. The Company believes that throughout the class period alleged in the lawsuit it fully and adequately disclosed all material facts regarding the Company and made no misrepresentations of material facts regarding Avista Corp. The Company nonetheless considers it desirable to settle the lawsuit in order to avoid the cost and risks of further litigation and trial, and to dispose of burdensome and protracted litigation.

The settlement agreement must be approved by the Court before it will become effective. The Court's approval process has several steps. The settlement agreement is first presented to the Court for preliminary approval. If the Court grants preliminary approval of the settlement agreement, then there will follow a period in which plaintiffs' counsel give notice of and administer the settlement agreement. A fairness hearing will be held at which the Court will judge the fairness, reasonableness and adequacy of the settlement agreement, including payment of plaintiffs' and plaintiffs' counsel fees and expenses, and at which any objections to the settlement agreement will be heard. If the Court then grants final approval of the settlement agreement, it will enter an order certifying the class and dismissing the claims in the lawsuit with prejudice. The Court's decision can be appealed. If the settlement agreement becomes effective, the settlement fund, less various costs of administration and plaintiffs' costs and attorney fees, will be distributed to class members who have filed an approved claim.

California Refund Proceeding

In July 2001, the FERC ordered an evidentiary hearing to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX) during the period from October 2, 2000 to June 20, 2001 (Refund Period). The findings of the FERC administrative law judge were largely adopted in March 2003 by the FERC. The refunds ordered are based on the development of a mitigated market clearing price (MMCP) methodology. If the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, the FERC has held that the seller would be allowed to document these costs and limit its refund liability commensurately. In September 2005, Avista Energy submitted its cost filing claim pursuant to the FERC's August 2005 order and demonstrated an overall revenue shortfall for sales into the California spot markets during the Refund Period after the MMCP methodology is applied to its transactions. That filing was accepted in orders issued by the FERC in January 2006 and November 2006. In its February 2007 status report, the CalISO stated that it intends to process Avista Energy's cost offset filing. In July 2007, the CalISO filed an updated status report at the FERC stating that it continues finalizing the financial adjustment phase, in which the CalISO is making adjustments to its refund rerun settlement data to account for fuel cost allowance offsets, emission offsets, cost-based offsets, and interest on amounts unpaid and refunds. Although no completion date was specifically projected, the CalISO stated that it will distribute interest calculations on refunds two weeks after all offsets are finalized.

In 2001, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) defaulted on payment obligations to the CalPX and the CalISO. As a result, the CalPX and the CalISO failed to pay various energy sellers, including Avista Energy. Both PG&E and the CalPX declared bankruptcy in 2001. In March 2002, SCE paid its defaulted obligations to the CalPX. In April 2004, PG&E paid its defaulted obligations into an escrow fund in accordance with its bankruptcy reorganization. Funds held by the CalPX and in the PG&E escrow fund are not subject to release until the FERC issues an order directing such release in the California refund proceeding. As of June 30, 2007, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from defaulting parties.

In addition, in June 2003, the FERC issued an order to review bids above $250 per MW made by participants in the short-term energy markets operated by the CalISO and the CalPX from May 1, 2000 to October 2, 2000. In May 2004, the FERC provided notice that Avista Energy was no longer subject to this investigation. In March and April 2005, the California Parties and PG&E, respectively, petitioned for review of the FERC's decision by the United States Court of Appeals for the Ninth Circuit. In addition, many of the other orders that the FERC has issued in the California refund proceedings are now on appeal before the Ninth Circuit. Some of those issues have been consolidated as a result of a case management conference conducted in September 2004. In October 2004, the Ninth Circuit ordered that briefing proceed in two rounds. The first round is limited to three issues: (1) which parties are subject to the FERC's refund jurisdiction in light of the exemption for government-owned utilities in section 201(f) of the Federal Power Act (FPA); (2) the temporal scope of refunds under section 206 of the FPA; and (3) which categories of transactions are subject to refunds. In September 2005, the Ninth Circuit held that the FERC did not have the authority to order refunds for sales made by municipal utilities in the California Refund Case. In August 2006, the Ninth Circuit upheld October 2, 2000 as the refund effective date for the FPA section 206 Refund Proceeding, but remanded to the FERC its decision not to consider a FPA section 309 remedy for tariff violations prior to October 2, 2000. The Ninth Circuit also granted California's petition for review challenging the FERC's exclusion of the energy exchange transactions as well as the FERC's exclusion of forward market transactions from the California refund proceedings. The Ninth Circuit has extended until August 13, 2007, the time for filing petitions for rehearing. It is unclear at this time what impact, if any, the Court's remand might have on Avista Energy. The second round of issues and their corresponding briefing schedules have not yet been set by the Ninth Circuit Court of Appeals.

Any potential liabilities or refunds owed by or to Avista Energy in the California Refund Proceeding have been assumed by Avista Corp. and/or its subsidiaries and have not been transferred to Coral Energy and/or its affiliates. Because the resolution of the California refund proceeding remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect that the California refund proceeding will have a material adverse effect on its financial condition, results of operations or cash flows. This is primarily due to the fact that FERC orders have stated that any refunds will be netted against unpaid amounts owed to the respective parties and the Company does not believe that refunds would exceed unpaid amounts owed to the Company.

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. During the hearing, Avista Utilities and Avista Energy vigorously opposed claims that rates for spot market sales were unjust and unreasonable and that the imposition of refunds would be appropriate. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. Seven petitions for review, including one filed by Puget Sound Energy, Inc. (Puget), are now pending before the United States Court of Appeals for the Ninth Circuit. Opening briefs were filed in January 2005. Petitioners other than Puget challenged the merits of the FERC's decision not to order refunds. Puget's brief is directed to the procedural flaws in the underlying docket. Puget argues that because its complaint was withdrawn as a matter of law in July 2001, the FERC erred in relying on it to serve as the basis to initiate the preliminary investigation into whether refunds for individually negotiated bilateral transactions in the Pacific Northwest were appropriate. In February 2005, intervening parties, including Avista Energy and Avista Utilities, filed in support of Puget and also filed in opposition to petitioners seeking refunds. Briefing was completed in May 2005 and oral arguments were heard on January 8, 2007. Because the resolution of the Pacific Northwest refund proceeding remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect that the Pacific Northwest refund proceeding will have a material adverse effect on its financial condition, results of operations or cash flows.

California Attorney General Complaint

In May 2002, the FERC conditionally dismissed a complaint filed in March 2002 by the Attorney General of the State of California (California AG) that alleged violations of the Federal Power Act by the FERC and all sellers (including Avista Corp. and its subsidiaries) of electric power and energy into California. The complaint alleged that the FERC's adoption and implementation of market-based rate authority was flawed and, as a result, individual sellers should refund the difference between the rate charged and a just and reasonable rate. In May 2002, the FERC issued an order dismissing the complaint but directing sellers to re-file certain transaction summaries. It was not clear that Avista Corp. and its subsidiaries were subject to this directive but the Company took the conservative approach and re-filed certain transaction summaries in June and July of 2002. In July 2002, the California AG requested a rehearing on the FERC order, which request was denied in September 2002. Subsequently, the California AG filed a Petition for Review of the FERC's decision with the United States Court of Appeals for the Ninth Circuit. In September 2004, the United States Court of Appeals for the Ninth Circuit upheld the FERC's market-based rate authority, but found the requirement that all sales at market-based rates be contained in quarterly reports filed with the FERC to be integral to a market-based rate tariff. The California AG has interpreted the decision as providing authority to the FERC to order refunds in the California refund proceeding for an expanded refund period. The Court's decision leaves to the FERC the determination as to whether refunds are appropriate. In October 2004, Avista Energy joined with others in seeking rehearing of the Court's decision to remand the case back to the FERC for further proceedings. The Court denied the request without explanation on July 31, 2006. Based on its current schedule, the Ninth Circuit will issue the mandate on this decision on August 13, 2007, which will return the case to the FERC for further proceedings. On December 28, 2006 certain parties filed a petition for a writ of certiorari at the Supreme Court. That petition was denied on June 18, 2007. Based on information currently known to the Company's management, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

Wah Chang Complaint

In May 2004, Wah Chang, a division of TDY Industries, Inc. (a subsidiary of Allegheny Technologies, Inc.), filed a complaint in the United States District Court for the District of Oregon against numerous companies, including

Avista Corp., Avista Energy and Avista Power. This complaint is similar to the Port of Seattle and City of Tacoma complaints (which were dismissed by the United States District Court and the United States Court of Appeals for the Ninth Circuit as disclosed in the Company's prior Securities and Exchange Commission filings) and seeks compensatory and treble damages for alleged violations of the Sherman Act, the Racketeer Influenced and Corrupt Organization Act, as well as violations of Oregon state law. According to the complaint, from September 1997 to September 2002, the plaintiff purchased electricity from PacifiCorp pursuant to a contract that was indexed to the spot wholesale market price of electricity. The plaintiff alleges that the defendants, acting in concert among themselves and/or with Enron Corporation and certain affiliates thereof (collectively, Enron) and others, engaged in a scheme to defraud electricity customers by transmitting false market information in interstate commerce in order to artificially increase the price of electricity provided by them, to receive payment for services not provided by them and to otherwise manipulate the market price of electricity, and by executing wash trades and other forms of market manipulation techniques and sham transactions. The plaintiff also alleges that the defendants, acting in concert among themselves and/or with Enron and others, engaged in numerous practices involving the generation, purchase, sale, exchange, scheduling and/or transmission of electricity with the purpose and effect of causing a shortage (or the appearance of a shortage) in the generation of electricity and congestion (or the appearance of congestion) in the transmission of electricity, with the ultimate purpose and effect of artificially and illegally fixing and raising the price of electricity in California and throughout the Pacific Northwest. As a result of the defendants' alleged conduct, the plaintiff allegedly suffered damages of not less than $30 million through the payment of higher electricity prices. In September 2004, this case was transferred to the United States District Court for the Southern District of California for consolidation with other pending actions. In February 2005, the Court granted the defendants' motion to dismiss the complaint because it determined that it was without jurisdiction to hear the plaintiff's complaint, based on, among other things, the exclusive jurisdiction of the FERC and the filed-rate doctrine. In March 2005, Wah Chang filed an appeal with the United States Court of Appeals for the Ninth Circuit. The appeal of Wah Chang is still pending before the Ninth Circuit and oral arguments were heard on April 10, 2007. Because the resolution of this lawsuit remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect that this lawsuit will have a material adverse effect on its financial condition, results of operations or cash flows.

State of Montana Proceedings

In June 2003, the Attorney General of the State of Montana (Montana AG) filed a complaint in the Montana District Court on behalf of the people of Montana and the Flathead Electric Cooperative, Inc. against numerous companies, including Avista Corp. The complaint alleges that the companies illegally manipulated western electric and natural gas markets in 2000 and 2001. This case was subsequently moved to the United States District Court for the District of Montana; however, it has since been remanded back to the Montana District Court.

The Montana AG also petitioned the Montana Public Service Commission (MPSC) to fine public utilities $1,000 a day for each day it finds they engaged in alleged "deceptive, fraudulent, anticompetitive or abusive practices" and order refunds when consumers were forced to pay more than just and reasonable rates. In February 2004, the MPSC issued an order initiating investigation of the Montana retail electricity market for the purpose of determining whether there is evidence of unlawful manipulation of that market. The Montana AG has requested specific information from Avista Energy and Avista Corp. regarding their transactions within the state of Montana during the period from January 1, 2000 through December 31, 2001.

Because the resolution of these proceedings remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect that these proceedings will have a material adverse effect on its financial condition, results of operations or cash flows.

Montana Public School Trust Fund Lawsuit

In October 2003, a lawsuit was originally filed by two residents of the state of Montana in the United States District Court for the District of Montana against all private owners of hydroelectric dams in Montana, including Avista Corp. The lawsuit alleged that the hydroelectric facilities are located on state-owned riverbeds and the owners of the dams have never paid compensation to the state's public school trust fund. The lawsuit requests lease payments dating back to the construction of the respective dams and also requests damages for trespassing and unjust enrichment. In February 2004, the Company filed its motion to dismiss this lawsuit; PacifiCorp and PPL Montana, the other named defendants, also filed a motion to dismiss, or joined therein. In May 2004, the Montana AG filed a complaint on behalf of the state in the District Court to join in this lawsuit to allegedly protect and preserve state lands/school trust lands from use without compensation. In July 2004, the defendants (including Avista Corp.) filed a motion to dismiss the Montana AG's complaint. In September 2004, the motion to dismiss the Montana AG's complaint was denied, rejecting the defendants' argument, among other things, that the FERC has exclusive jurisdiction over this matter. In September 2005, the U.S. District Court issued an order vacating its prior decision based on lack of jurisdiction.

In November 2004, the defendants (including Avista Corp.) filed a petition for declaratory relief in Montana State Court requesting the resolution of the claim that the plaintiffs raised in federal court, as discussed above, and the Montana AG filed an answer, counterclaim and motion for summary judgment. In June 2005, Avista Corp. moved for leave to amend its complaint to, inter alia, add two causes of action relating to breach of contract and negligent misrepresentation arising out of its Clark Fork Settlement Agreement that was entered into in 1999 with the state of Montana relating to the relicensing of Avista Corp.'s Noxon Rapids Hydroelectric Generating Project. On April 14, 2006, the Montana State Court granted the Montana AG's motion for summary judgment and denied Avista Corp.'s motion to amend its complaint to add its breach of contract and negligent misrepresentation claims. However, the Montana State Court granted Avista Corp.'s motion to amend its complaint to contend that the Clark Fork River is not navigable. The Company contends that if the Clark Fork River was not navigable at the time of statehood in 1889, the state of Montana never acquired ownership of the riverbeds under the equal footing doctrine. The Court determined that the Montana AG's claims for compensation were not preempted by the Federal Power Act because the claims were not, on their face, in conflict with Montana law, nor were they preempted by a federal navigational right for purposes of interstate commerce. The Court also rejected defenses based on estoppel, waiver, and the statute of limitations. The Court did not relieve the Montana AG, however, of its obligation to prove that the state of Montana actually owns the riverbeds or that the land is part of a school trust under the Montana Constitution. In addition, the question of whether there is federal preemption under the Federal Power Act, not on its face, but as actually applied in these circumstances, and the question of compensation, still remain open issues in the case. On May 16, 2006, the state of Montana filed a motion for summary judgment on the question of liability. On October 6, 2006, the Company filed several motions, which addressed, among other things, the question of navigability of the Clark Fork River arguing that since the Clark Fork River was not navigable at the time of statehood, the state of Montana never acquired ownership of the riverbeds under the equal footing doctrine. Oral arguments on the Company's motions were heard in December 2006. The Company expects this matter to proceed in the normal course of litigation and a trial date is currently scheduled for October 2007. Mediation of this matter has been scheduled for September 2007. Because the resolution of this lawsuit remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, the Company intends to seek recovery, through the rate making process, of any amounts paid.

Colstrip Generating Project Complaints

In May 2003, various parties (all of which are residents or businesses of Colstrip, Montana) filed a consolidated complaint against the owners of the Colstrip Generating Project (Colstrip) in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs allege damages to buildings as a result of rising ground water, as well as damages from contaminated waters leaking from the lakes and ponds of Colstrip. The plaintiffs are seeking punitive damages, an order by the court to remove the lakes and ponds and the forfeiture of all profits earned from the generation of Colstrip. The owners of Colstrip have undertaken certain groundwater investigation and remediation measures to address groundwater contamination. These measures include improvements to the lakes and ponds of Colstrip.

In March 2007, a group of ranchers filed a consolidated complaint against the owners of Colstrip in Montana District Court. The plaintiffs allege damages to livestock, land and water from contaminated waters leaking from the waste water pond of Colstrip. The plaintiffs are seeking unspecified punitive damages.

The Company intends to continue to work with the other owners of Colstrip in defense of these complaints. Because the resolution of these lawsuits remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect that these lawsuits will have a material adverse effect on its financial condition, results of operations or cash flows.

Colstrip Royalty Claim

Western Energy Company (WECO) supplies coal to the owners of Colstrip Units 3 & 4 under a Coal Supply Agreement and a Transportation Agreement. Avista Corp. owns a 15 percent interest in Colstrip Units 3 & 4. The Minerals Management Service (MMS) of the United States Department of the Interior issued orders to WECO to pay additional royalties concerning coal delivered to Colstrip Units 3 & 4 via the conveyor belt (4.46 miles long). The owners of Colstrip Units 3 & 4 take delivery of the coal at the beginning of the conveyor belt. The orders assert that additional royalties are owed MMS as a result of WECO not paying royalties in connection with revenue received by

WECO from the owners of Colstrip Units 3 & 4 under the Transportation Agreement during the period October 1, 1991 through December 31, 2004. WECO's appeal to the MMS for the period through 2001 was substantially denied in March 2005; WECO has now appealed the orders pertaining to the periods up to 2001 to the Board of Land Appeals of the U.S. Department of the Interior. WECO has also filed an appeal with the MMS pertaining to the period from 2002 to 2004. The entire appeal process could take several years to resolve. The owners of Colstrip Units 3 & 4 are monitoring the appeal process between WECO and MMS. WECO has indicated to the owners of Colstrip Units 3 & 4 that if WECO is unsuccessful in the appeal process, WECO will seek reimbursement of any royalty payments by passing these costs through the Coal Supply Agreement. The owners of Colstrip Units 3 & 4 advised WECO that their position would be that these claims are not allowable costs per the Coal Supply Agreement nor the Transportation Agreement in the event the owners of Colstrip Units 3 & 4 were invoiced for these claims. Presumably, royalty and tax demands for periods of time after the years in dispute and future years will be determined by the outcome of the pending proceedings. Because the resolution of this issue remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. Based on information currently known to the Company's management, the Company does not expect that this issue will have a material adverse effect on its financial condition, results of operations or cash flows. However, the Company would most likely seek recovery, through the rate making process, of any amounts paid.

Spokane River

The Company has entered into a settlement with the state of Washington's Department of Ecology (DOE) and Kaiser Aluminum & Chemical Corporation (Kaiser) relating to the remediation of a contaminated site on the Spokane River. The Company's involvement with this contaminated site relates to its previous ownership of a wastewater treatment plant through Avista Development. Under the agreement with the DOE and Kaiser, the Company is performing the selected remedial action under the Cleanup Action Plan. Kaiser, operating under Chapter 11 bankruptcy protection, paid the Company approximately 50 percent of the estimated total costs, which was approved by the Kaiser bankruptcy judge. The funds from Kaiser have been used by the Company to pay a portion of the costs of the remediation. The Company accrued its share of the total estimated costs, which was not material to the Company's financial condition or results of operations. Under the direction of the Company, work under the Cleanup Action Plan was substantially completed by January 2007. Some minor final work should be completed in the second half of 2007.

Northeast Combustion Turbine Site

In August 2005, a diesel fuel spill occurred at the Company's Northeast Combustion Turbine generating facility (Northeast CT) located in Spokane, Washington. The Northeast CT site had fuel storage facilities that were leased to Co-op Supply, Inc., an affiliate of Cenex Cooperative (Co-op). The fuel spill occurred when Co-op made a delivery of diesel to a tank that was already nearly full, causing excess fuel to overflow into a containment area. Fuel escaped the containment area and leaked into the soil below it. The Company immediately commenced remediation efforts, including the removal of contaminated soil and the related fuel storage facilities. The Company accrued the estimated cleanup costs during 2005, which was not material to the Company's consolidated financial condition or results of operations. Through mediation the Company recovered a substantial portion of the cleanup costs from Co-op and an engineering firm in the fourth quarter of 2006. The Company's estimate of its liability could change in future periods. Based on information currently known to the Company's management, the Company does not believe that such a change would be material to its financial condition, results of operations or cash flows.

Harbor Oil Inc. Site

Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, EPA Region 10 provided notification to Avista Corp., as a customer of Harbor Oil, that the EPA had determined that hazardous substances were released at the Harbor Oil site in Portland, Oregon and that Avista Corp. may be liable for investigation and cleanup of the site under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as the federal "Superfund" law. Harbor Oil's primary business was the collection and blending of used oil for sale as fuel to ships at sea. The initial indication from the EPA is that the site may be contaminated with PCBs, petroleum hydrocarbons, chlorinated solvents and heavy metals. Thirteen other companies received a similar notice, including current and former owners of the site. Six potentially responsible parties, including Avista Corp., signed an Administrative Order on Consent with the EPA on May 31, 2007 to conduct a remedial investigation and feasibility study (RI/FS). The total cost of the RI/FS is estimated to be $0.6 million and will take approximately 2 1/2 years to complete. The actual cleanup, if any, will not occur until the RI/FS is complete. Based on the review of its records related to Harbor Oil, the Company does not believe it is a major contributor to this potential environmental contamination based on the relative volume of waste oil delivered to the Harbor Oil site. However, there is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred. As such, it is not possible to make an estimate of any liability at this time.

Lake Coeur d'Alene

In July 1998, the United States District Court for the District of Idaho issued its finding that the Coeur d'Alene Tribe of Idaho (Tribe) owns, among other things, portions of the bed and banks of Lake Coeur d'Alene (Lake) lying within the current boundaries of the Coeur d'Alene Reservation. This action had been brought by the United States on behalf of the Tribe against the state of Idaho. The Company was not a party to this action. The United States District Court decision was affirmed by the United States Court of Appeals for the Ninth Circuit. The United States Supreme Court affirmed this decision in June 2001. This ownership decision will result in, among other things, the Company being liable to the Tribe for compensation for the use of reservation lands under Section 10(e) of the Federal Power Act.

The Company's Post Falls Hydroelectric Generating Station (Post Falls), a facility constructed in 1906 with annual generation of 10 aMW, utilizes a dam on the Spokane River downstream of the Lake which controls the water level in the Lake for portions of the year (including portions of the lakebed owned by the Tribe). The Company has other hydroelectric facilities on the Spokane River downstream of Post Falls, but these facilities do not affect the water level in the Lake. The Company and the Tribe are engaged in discussions related to past and future compensation (which may include interest) for use of the portions of the bed and banks of the Lake, which are owned by the Tribe. If the parties cannot agree on the amount of compensation, the matter could result in litigation. The Company cannot predict the amount of compensation that it will ultimately pay or the terms of such payment. The Company intends to seek recovery, through the rate making process, of any amounts paid.

Spokane River Relicensing

The Company owns and operates six hydroelectric plants on the Spokane River, and five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls, which have a total present capability of 155.7 MW) are under one FERC license and are referred to as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. Since the FERC was unable to issue new license orders prior to the August 1, 2007 expiration of the current license, an annual license has been issued, in effect extending the current license and its conditions. The Company has no reason to believe that Spokane River Project operations will be interrupted in any manner relative to the timing of the FERC's actions.

The Company filed a Notice of Intent to Relicense in July 2002. The formal consultation process involving planning and information gathering with stakeholder groups has been underway since that time. The Company filed its new license applications with the FERC in July 2005. The Company has requested the FERC to consider a license for Post Falls, which has a present capability of 18 MW, that is separate from the other four hydroelectric plants because Post Falls presents more complex issues that may take longer to resolve than those dealing with the rest of the Spokane River Project. If granted, new licenses would have a term of 30 to 50 years. In the license applications, the Company proposed a number of measures intended to address the impact of the Spokane River Project and enhance resources associated with the Spokane River.

Since the Company's July 2005 filing of applications to relicense the Spokane River Project, the FERC has continued various stages of processing the applications. In May 2006, the FERC issued a notice calling for terms and conditions regarding the two license applications. In response to that notice, a number of parties (including the Coeur d'Alene Tribe, the state of Idaho, Washington State agencies, and the United States Department of Interior (DOI)) filed either recommended terms and conditions, pursuant to Sections 10(a) and 10(j) of the Federal Power Act (FPA), or mandatory conditions related to the Post Falls application, pursuant to Section 4(e) of the FPA. The Company's initial estimate of the potential cost of the conditions proposed for Post Falls total between $400 million and $500 million over a 50-year period. For the rest of the Spokane River Project, which is located in Washington, the Company's initial estimate of the cost of meeting the recommended conditions, should they be included in a final license, totaled between $175 million and $225 million over a 50-year period. These cost estimates were based on the preliminary conditions and recommendations.

The Company requested a trial-type hearing on facts in front of an Administrative Law Judge (ALJ) related to the DOI's mandatory conditions for Post Falls. In January 2007, the ALJ issued his ruling regarding the Company's challenge of the facts. The Company believes that the ALJ's factual findings supported, in several key areas, its analysis of the facts at hand. The ALJ's factual findings also supported the DOI's analysis in certain areas as well.

The DOI issued final mandatory conditions for Post Falls on May 7, 2007. The final conditions did change reflecting the findings of the ALJ. Most significantly, the DOI dropped an earlier proposed fishery condition. However, the DOI increased obligations that the Company could incur in other areas, such as wetlands restoration.

In July 2007, the FERC issued a Final Environmental Impact Statement (FEIS) after review and consideration of comments. This is the last administrative step for the FERC before the issuance of license orders; however the FERC cannot proceed until several other matters are resolved, including Clean Water Act and Endangered Species Act issues as disclosed below. The Company is in the process of reviewing the FEIS. While the Company believes the ultimate cost of relicensing will be less than its earlier projections as disclosed above, the Company is unable to base specific new cost estimates on its analysis of the final terms and conditions issued by the DOI and the FEIS at this point.

The relicensing process also triggers review under the Endangered Species Act. In the FEIS, the FERC analyzed potential project impacts on listed and threatened endangered species, and has determined that the proposed action and continued operation of the Post Falls and Spokane River projects is not likely to adversely affect any threatened or endangered species. The Company prepared a draft Biological Assessment in 2005. The FERC has issued a Biological Assessment and formally requested concurrence from the United States Department of Fish and Wildlife Service (USFWS). The USFWS responded by letter, concurring with regards to bald eagles, and requesting additional information regarding bull trout. The Company has filed a supplemental report to address the USFWS information request. If the FERC initiates formal consultation with the USFWS, additional evaluation will be required by the Company.

In addition, the Company must receive Clean Water Act Certifications from the states of Idaho and Washington for the Projects. Applications for such certification were filed last July with each state; the FERC is precluded from issuing a license order until such certification has been issued, or waived, by the states. The Company cannot predict the schedule for these final phases of relicensing.

The total annual operating and capitalized costs associated with the relicensing of the Spokane River Project will become better known and estimable as the process continues. The Company intends to seek recovery, through the rate making process, of all such operating and capitalized costs.

Clark Fork Settlement Agreement

Dissolved atmospheric gas levels exceed state of Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement, the Company developed an abatement and mitigation strategy with the other signatories to the agreement and completed the Gas Supersaturation Control Program (GSCP). The Idaho Department of Environmental Quality and the USFWS approved the GSCP in February 2004 and the FERC issued an order approving the GSCP in January 2005.

The GSCP provides for the opening and modification of one and, potentially, both of the two existing diversion tunnels built when Cabinet Gorge was originally constructed. When river flows exceed the capacity of the powerhouse turbines, the excess flows would be diverted to the tunnels rather than released over the spillway. The Company has undertaken physical and computer modeling studies to confirm the feasibility and likely effectiveness of its tunnel solution. The Company has completed its preliminary design development efforts (which include additional computer model studies, some site investigation, and preliminary engineering design) and the cost estimates have been updated. Analysis of the predicted total dissolved gas (TDG) performance indicates that the tunnels are unlikely to meet the performance criteria anticipated in the GSCP. The costs of modifying the first tunnel are now estimated to be $58 million (using 2006 dollars with inflation projected at 5 percent) with the majority of these costs to be incurred in 2008 through 2012, an increase from prior estimates of $38 million and an extension of the schedule. The calculated updated cost estimates to modify the second tunnel are $39 million, an increase from prior estimates of $26 million. The second tunnel would be modified only after evaluation of the performance of the first tunnel and such modifications would commence no later than ten years following the completion of the first tunnel. The increases in costs are mainly due to inflation and large increases in materials costs, such as concrete and steel. Efforts will continue throughout 2007 toward the completion of a final Design Development Report, which will include updated tunnel performance predictions, cost estimates, and schedule. As a result of the predicted TDG performance, the new cost estimates and extension of the schedule, the Company will continue meeting with stakeholders to explore amending the GSCP and possible alternatives to the construction of the tunnels. The Company intends to seek recovery, through the rate making process, of the costs to address the dissolved atmospheric gas levels, including the mitigation payments.

The USFWS has listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company is evaluating the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies will help the Company and other parties determine the best use of funds toward continuing fish passage efforts or other bull trout population enhancement measures.

Air Quality

The Company must be in compliance with requirements under the Clean Air Act and Clean Air Act Amendments for its thermal generating plants. The Company continues to monitor legislative developments at both the state and national level for the potential of further restrictions on sulfur dioxide, nitrogen oxide, carbon dioxide (including cap and trade emission reduction programs), as well as other greenhouse gas and mercury emissions.

In particular, the EPA has finalized mercury emission regulations that will affect coal-fired generation plants, including Colstrip. The new EPA regulations establish an emission trading program to take effect beginning in January 2010, with a second phase to take effect in 2018. In addition, in 2006, the Montana DEQ adopted final rules for the control of mercury emissions from coal-fired plants that are more restrictive than EPA regulations. The new rules set strict mercury emission limits by 2010, and put in place a recurring ten-year review process to ensure facilities are keeping pace with advancing technology in mercury emission control. The rules also provide for temporary alternate emission limits provided certain provisions are met, and they allocate mercury emission credits in a manner that rewards the cleanest facilities. Avista Corp. owns a 15 percent interest in Colstrip Units 3 & 4, located in Montana.

Compliance with these new and proposed requirements and possible additional legislation or regulations will result in increases to capital expenditures and operating expenses for expanded emission controls at the Company's thermal generating facilities. The Company, along with the other owners of Colstrip, are in the process of testing technologies and computing estimates for the amount of these costs and the impact the restrictions will have on the operation of the facilities. The Company will continue to seek recovery, through the rate making process, of the costs to comply with various air quality requirements.

Residential Exchange Program

The residential exchange program provides access to the benefits of low-cost federal hydroelectricity to residential and small-farm customers of the region's investor-owned utilities. The Bonneville Power Administration (BPA) administers the residential exchange program under the Northwest Power Act. Previously, Avista Corp. and the other investor-owned utilities (IOUs) in the Pacific Northwest had executed settlement agreements with BPA to resolve each party's rights and obligations under the residential exchange program. These settlements covered payment of benefits for the period October 1, 2001, through September 30, 2011. The payments Avista Corp. received under the agreements with BPA were passed through directly to its residential and small-farm customers via a credit to their monthly electric bills.

At the time the settlement agreements were concluded, several public power and other parties filed suit against BPA in the United States Ninth Circuit Court of Appeals, challenging the validity of the agreements between Avista Corp. and BPA, as well as BPA's agreements with the other IOUs. And on May 3, 2007, the Ninth Circuit ruled that BPA had exceeded its authority when it entered into the settlement agreements with the IOUs (including Avista Corp.) for the period from 2001 through 2011. The panel concluded that those settlement agreements were inconsistent with the Northwest Power Act. BPA concluded that the Ninth Circuit's decisions created substantial doubt about whether its certifying official could allow continuation of payments under the settlement agreements. Consequently, on May 21, 2007, the BPA notified Avista Corp. and the other IOUs that it was immediately suspending payments made to the IOUs pursuant to settlement agreements. In its May 21, 2007 notice, BPA indicated that the suspension of payments would continue at least until any requests for rehearing were filed and the Ninth Circuit issued final decisions on those requests for rehearing. On July 18, 2007 Avista Corp. and numerous other parties, including the Public Utility Commission of Oregon and the WUTC, filed Petitions for Review, *en banc*, in the United States Ninth Circuit Court of Appeals, challenging the ruling of panel that struck down the settlement agreements.

With approval from the WUTC and the IPUC, Avista Corp. has eliminated from its customers' monthly electric bills, the credit associated with the settlement agreements with BPA. Avista Corp. has an over-refunded balance of approximately $4.7 million ($3.2 million in Washington and $1.5 million in Idaho). Avista Corp. will recover the over-refund in Idaho through an approved surcharge to customers, and expects to ultimately recover the over-refund in Washington, either through a charge to customers or future payments from BPA. The over-refunded balance results from the timing of payments received from the BPA and allocation of those funds to customers based on seasonal demand. When the existing rate credit was established it was projected that the balancing account would reach zero at the end of the contract year (October 2007).

Since these payments were passed through to Avista Corp.'s customers as adjustments to electric bills, the suspension of payments from BPA is not expected to have any effect on Avista Corp.'s net income. There is currently not enough information to allow Avista Corp. to assess the probability or amount of any potential liability that may be incurred related to any issues regarding payments made to Avista Corp. pursuant to the settlement agreements. Since 2001, Avista Corp. has passed through to its customers approximately $70 million pursuant to the settlement agreements.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material adverse impact on its financial condition, results of operations or cash flows. It is possible that a change could occur in the Company's estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant.

NOTE 13. POTENTIAL HOLDING COMPANY FORMATION

At the 2006 Annual Meeting of Shareholders in May 2006, the shareholders of Avista Corp. approved a proposal to proceed with a statutory share exchange, which would change the Company's organization to a holding company structure. The holding company, currently named AVA Formation Corp. (AVA), would become the parent of Avista Corp. After the contemplated dividend to AVA of the capital stock of Avista Capital (Avista Capital Dividend) now held by Avista Corp., AVA would then also be the parent of Avista Capital. The Avista Capital Dividend would effect the structural separation of Avista Corp.'s non-utility businesses from its regulated utility business. Since the company's 9.75 percent Senior Notes due June 1, 2008 contain a restriction that would prohibit the Avista Capital Dividend (but not the holding company structure), the dividend would not be distributed until the Senior Notes are retired.

Avista Corp. received approval from the FERC in April 2006 (conditioned on approval by the state regulatory agencies), the IPUC in June 2006 and the WUTC in February 2007. Avista Corp. has also filed for approval from the utility regulators in Oregon and Montana and proceedings are pending in each of these jurisdictions. The statutory share exchange is subject to the receipt of the remaining regulatory approvals and the satisfaction of other conditions. If the statutory share exchange and the implementation of the holding company structure are approved by regulators on terms acceptable to the Company, it may be completed sometime in 2008.

The IPUC accepted a stipulation entered into between Avista Corp. and the IPUC Staff that sets forth a variety of conditions, which would serve to segregate the Company's utility operations from the other businesses conducted by the holding company. The stipulation would require Avista Corp. to maintain certain common equity levels as part of its capital structure. Avista Corp. has committed to increase its actual utility common equity component to 35 percent by the end of 2007 and 38 percent by the end of 2008, which is consistent with provisions of the Company's Washington general rate case implemented on January 1, 2006. The calculation of the utility equity component is essentially the ratio of Avista Corp.'s total common equity to total capitalization excluding, in each case, Avista Corp.'s investment in Avista Capital. In addition, IPUC approval would be required for any dividend from Avista Corp. to the holding company that would reduce utility common equity below 25 percent of total capitalization which, for this purpose, includes long and short-term debt, capitalized lease obligations and preferred and common equity.

The WUTC accepted a similar stipulation entered into between Avista Corp. and the WUTC staff. The stipulation requires Avista Corp. to increase its actual utility common equity component to 40 percent by June 30, 2008. In addition, WUTC approval would be required for any dividend from Avista Corp. to the holding company that would reduce utility common equity below 30 percent of total capitalization.

Pursuant to the Plan of Share Exchange, a statutory share exchange would be effected whereby each outstanding share of Avista Corp. common stock would be exchanged for one share of AVA common stock, no par value, so that holders of Avista Corp. common stock would become holders of AVA common stock and Avista Corp. would become a subsidiary of AVA. The other outstanding securities of Avista Corp. would not be affected by the statutory share exchange, with limited exceptions for stock options and other securities outstanding under equity compensation and employee benefit plans.

NOTE 14. RESTATEMENT OF FINANCIAL STATEMENTS

During preparation of the Company's Form 10-Q for the quarter ended June 30, 2007, the Company determined that SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" was inadvertently not followed in connection with a plan under which benefits are provided to the beneficiaries of former and current executive officers of the Company in case of death. The Company has not previously recognized the actuarial liability or costs relating to this plan in its financial statements since the plan's inception in 1989.

The Company has determined that this accounting error is not material to its previously issued financial statements. As such, in accordance with the provisions of Securities and Exchange Commission Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements," the Company will reflect the correction of this error in those financial statements when they are included in future filings with the Securities and Exchange Commission, including this Form 10-Q and the Annual Report on Form 10-K for the year ended December 31, 2007.

The restatement adjustments have the cumulative effect of reducing retained earnings by $2.1 million as of January 1, 2005. The adjustments increase pensions and other postretirement liabilities by $3.6 million, decrease non-current deferred tax liabilities by $1.3 million, decrease accumulated other comprehensive loss by $0.2 million and decrease retained earnings by $2.5 million as of December 31, 2006. In addition, previously reported net income of $73.1 million and $45.2 million for the years ended December 31, 2006 and 2005 will each be reduced by $0.2 million.

As the restatement adjustments are not material to the results of operations for fiscal year 2006 or any quarterly period of 2006, the Company has not restated its Consolidated Statements of Income for the three and six months ended June 30, 2006. The effect of the restatement adjustments on affected line items of the Consolidated Balance Sheet as of December 31, 2006 was as follows (dollars in thousands):

	As Previously Reported	Adjustments	As Restated
Pensions and other postretirement benefits	$ 100,033	$ 3,571	$ 103,604
Deferred income taxes	461,006	(1,250)	459,756
Total other non-current liabilities and deferred credits	1,131,196	2,321	1,133,517
Total liabilities	3,139,662	2,321	3,141,983
Accumulated other comprehensive loss	(17,966)	150	(17,816)
Retained earnings	219,192	(2,471)	216,721
Total stockholders' equity	916,846	(2,321)	914,525

NOTE 15. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis currently used by the Company's management to analyze performance and determine the allocation of resources. Avista Utilities' business is managed based on the total regulated utility operation. The Energy Marketing and Resource Management business segment primarily consisted of electricity and natural gas marketing, trading and resource management, including optimization of energy assets owned by other entities and derivative commodity instruments such as futures, options, swaps and other contractual arrangements. On June 30, 2007, Avista Energy and Avista Energy Canada completed the sale of substantially all of their contracts and ongoing operations. This transaction effectively ends substantially all of the operations of the Energy Marketing and Resource Management business segment. See Note 3 for further information. Advantage IQ is a provider of facility information and cost management services for multi-site customers throughout North America. The Other business segment includes other investments and operations of various subsidiaries as well as certain other operations of Avista Capital.

The following table presents information for each of the Company's business segments (dollars in thousands):

	Avista Utilities	Energy Marketing and Resource Management	Advantage IQ	Other	Intersegment Eliminations (1)	Total
For the three months ended June 30, 2007:						
Operating revenues	$ 267,997	$ 19,398	$ 11,415	$ 5,195	$ —	$ 304,005
Resource costs	135,520	18,386	—	—	—	153,906
Gross margin	132,477	1,012	—	—	—	133,489
Other operating expenses	50,191	8,336	8,629	5,207	—	72,363
Depreciation and amortization	21,298	167	601	402	—	22,468
Income (loss) from operations	45,938	(7,491)	2,185	(414)	—	40,218
Interest expense (2)	22,047	71	72	253	(392)	22,051
Income taxes	9,412	(967)	777	(433)	—	8,789
Net income (loss)	17,257	(3,938)	1,310	(446)	—	14,183
Capital expenditures	52,071	112	494	44	—	52,721
For the three months ended June 30, 2006:						
Operating revenues	$ 258,076	$ 14,315	$ 9,545	$ 5,458	$ —	$ 287,394
Resource costs	122,086	18,196	—	—	—	140,282
Gross margin	135,990	(3,881)	—	—	—	132,109
Other operating expenses	48,218	4,773	6,497	5,299	—	64,787
Depreciation and amortization	20,111	252	485	576	—	21,424
Income (loss) from operations	49,338	(8,906)	2,563	(417)	—	42,578
Interest expense (2)	23,826	53	158	523	(586)	23,974
Income taxes	10,067	(2,486)	848	(561)	—	7,868
Net income (loss)	16,879	(4,610)	1,558	(368)	—	13,459
Capital expenditures	43,535	268	602	16	—	44,421
For the six months ended June 30, 2007:						
Operating revenues	$ 682,263	$ 48,807	$ 22,414	$ 9,708	$ —	$ 763,192
Resource costs	405,506	56,113	—	—	—	461,619
Gross margin	276,757	(7,306)	—	—	—	269,451
Other operating expenses	99,232	13,420	16,456	9,432	—	138,540
Depreciation and amortization	42,388	345	1,197	903	—	44,833
Income (loss) from operations	96,092	(21,071)	4,761	(627)	—	79,155
Interest expense (2)	44,050	154	153	442	(565)	44,234
Income taxes	20,407	(5,298)	1,689	(522)	—	16,276
Net income (loss)	37,184	(11,561)	2,894	(240)	—	28,277
Capital expenditures	92,626	318	1,252	419	—	94,615
For the six months ended June 30, 2006:						
Operating revenues	$ 681,366	$ 75,857	$ 18,622	$ 10,751	$ —	$ 786,596
Resource costs	393,691	68,323	—	—	—	462,014
Gross margin	287,675	7,534	—	—	—	295,209
Other operating expenses	93,945	9,527	12,660	10,693	—	126,825
Depreciation and amortization	41,091	593	1,000	1,168	—	43,852
Income (loss) from operations	112,250	(2,586)	4,962	(1,110)	—	113,516
Interest expense (2)	47,506	99	354	1,091	(1,227)	47,823
Income taxes	25,878	223	1,623	(1,339)	—	26,385
Net income (loss)	43,051	436	2,985	(1,441)	—	45,031
Capital expenditures	73,278	539	967	17	—	74,801
Total Assets:						
Total assets as of June 30, 2007	$ 2,844,371	$ 315,119	$ 102,330	$ 43,310	$ —	$ 3,305,130
Total assets as of December 31, 2006	2,895,883	1,017,203	100,431	42,991	—	4,056,508

(1) Intersegment eliminations reported as interest expense represent intercompany interest.
(2) Including interest expense to affiliated trusts.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Avista Corporation
Spokane, Washington

We have reviewed the accompanying consolidated balance sheet of Avista Corporation and subsidiaries (the "Corporation") as of June 30, 2007, and the related consolidated statements of income and of comprehensive income for the three-month and six-month periods ended June 30 2007 and 2006, and of cash flows for the six-month periods ended June 30, 2007 and 2006. These interim financial statements are the responsibility of the Corporation's management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to such consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Avista Corporation and subsidiaries as of December 31, 2006, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for the year then ended (not presented herein) prior to the restatement described in Note 14 to the accompanying consolidated financial statements; and in our report dated February 26, 2007, we expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph for certain changes in accounting and presentation resulting from the impact of recently adopted accounting standards. We also audited the adjustments described in Note 14 that were applied to restate the December 31, 2006 consolidated balance sheet of Avista Corporation and subsidiaries (not presented herein). In our opinion, such adjustments are appropriate and have been properly applied to the previously issued consolidated balance sheet in deriving the accompanying restated consolidated balance sheet as of December 31, 2006.

/s/ Deloitte & Touche LLP

August 6, 2007

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Forward-Looking Statements

From time to time, we make forward-looking statements such as statements regarding projected or future:

- financial performance,
- capital expenditures,
- dividends,
- capital structure,
- other financial items,
- strategic goals and objectives, and
- plans for operations.

These statements have underlying assumptions (many of which are based, in turn, upon further assumptions). Such statements are made both in our reports filed under the Securities Exchange Act of 1934, as amended (including this Quarterly Report on Form 10-Q), and elsewhere. Forward-looking statements are all statements except those of historical fact including, without limitation, those that are identified by the use of words that include "will," "may," "could," "should," "intends," "plans," "seeks," "anticipates," "estimates," "expects," "forecasts," "projects," "predicts," and similar expressions.

All forward-looking statements (including those made in this Quarterly Report on Form 10-Q) are subject to a variety of risks and uncertainties and other factors. Most of these factors are beyond our control and many of them could have a significant effect on our operations, results of operations, financial condition or cash flows. This could cause actual results to differ materially from those anticipated in our statements. Such risks, uncertainties and other factors include, among others:

- weather conditions and its effect on energy demand and generation, including the effect of precipitation and temperatures on the availability of hydroelectric resources and the effect of temperatures on customer demand;
- changes in wholesale energy prices that can affect, among other things, cash needed to purchase electricity, natural gas for our retail customers and natural gas fuel for electric generation, and the value of surplus energy sold, as well as the market value of derivative assets and liabilities;
- volatility and illiquidity in wholesale energy markets, including the availability of generation and prices of purchased energy and demand for energy sales;
- the effect of state and federal regulatory decisions affecting our ability to recover costs and/or earn a reasonable return including, but not limited to, the disallowance of costs that we have deferred;
- the outcome of pending regulatory and legal proceedings arising out of the "western energy crisis" of 2000 and 2001, and including possible retroactive price caps and resulting refunds;
- the outcome of legal proceedings and other contingencies concerning us or affecting directly or indirectly our operations;
- the potential effects of any legislation or administrative rulemaking passed into law, including the possible adoption of national, regional, or state laws requiring all new resources to meet certain standards and placing restrictions on greenhouse gas emissions and global warming;
- changes in, and compliance with, environmental and endangered species laws, regulations, decisions and policies, including present and potential environmental remediation costs;
- the potential impact of changes to electric transmission ownership, operation and governance, such as the formation of one or more regional transmission organizations or similar entities;
- wholesale and retail competition including, but not limited to, electric retail wheeling and transmission costs;
- the ability to relicense and maintain licenses for our hydroelectric generating facilities at cost-effective levels with reasonable terms and conditions;
- unplanned outages at any of our generating facilities or the inability of facilities to operate as intended;
- unanticipated delays or changes in construction costs, as well as our ability to obtain required operating permits for present or prospective facilities;
- natural disasters that can disrupt energy production or delivery, as well as the availability and costs of materials and supplies and support services;
- blackouts or disruptions of interconnected transmission systems;
- the potential for future terrorist attacks or other malicious acts, particularly with respect to our utility assets;
- changes in the long-term climate of the Pacific Northwest, which can affect, among other things, customer demand patterns and the volume and timing of streamflows to our hydroelectric resources;
- changes in future economic conditions in our service territory and the United States in general, including inflation or deflation and monetary policy;

- changes in industrial, commercial and residential growth and demographic patterns in our service territory;
- the loss of significant customers and/or suppliers;
- failure to deliver on the part of any parties from which we purchase and/or sell capacity or energy;
- changes in the creditworthiness of our customers and energy trading counterparties;
- our ability to obtain financing through the issuance of debt and/or equity securities, which can be affected by various factors including our credit ratings, interest rates and other capital market conditions;
- the effect of any change in our credit ratings;
- changes in actuarial assumptions, the interest rate environment and the actual return on plan assets for our pension plan, which can affect future funding obligations, costs and pension plan liabilities;
- increasing health care costs and the resulting effect on health insurance premiums paid for our employees and retirees;
- increasing costs of insurance, changes in coverage terms and our ability to obtain insurance;
- employee issues, including changes in collective bargaining unit agreements, strikes, work stoppages or the loss of key executives, as well as our ability to recruit and retain employees;
- the potential effects of negative publicity regarding business practices, whether true or not, which could result in, among other things, costly litigation and a decline in our common stock price;
- changes in technologies, possibly making some of the current technology quickly obsolete;
- changes in tax rates and/or policies; and
- changes in our strategic business plans and/or our subsidiaries, which may be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses.

Our expectations, beliefs and projections are expressed in good faith. We believe they have a reasonable basis including, without limitation, an examination of historical operating trends, data contained in our records and other data available from third parties. However, there can be no assurance that our expectations, beliefs or projections will be achieved or accomplished. Furthermore, any forward-looking statement speaks only as of the date on which such statement is made. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for us to predict all of such factors, nor can we assess the effect of each such factor on our business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

The following discussion and analysis is provided for the consolidated financial condition and results of operations of Avista Corp. and its subsidiaries. This discussion focuses on significant factors concerning our financial condition and results of operations and should be read along with the consolidated financial statements.

Potential Holding Company Formation

In May 2006, our shareholders approved a proposal to proceed with a statutory share exchange, which would change our organization to a holding company structure. If the implementation of the holding company structure is approved by all regulators on terms acceptable to us, it may be completed sometime in 2008. See further information at "Note 13 of the Notes to Consolidated Financial Statements."

Business Segments

We have four business segments as follows:

- **Avista Utilities** – generation, transmission and distribution of electric energy and distribution of natural gas to retail customers, as well as wholesale purchases and sales of energy commodities. Avista Utilities is an operating division of Avista Corp. comprising our regulated utility operations.
- **Energy Marketing and Resource Management** – electricity and natural gas marketing, trading and resource management. The activities of this business segment were conducted primarily by Avista Energy, Inc., an indirect subsidiary of Avista Corp. On June 30, 2007, Avista Energy and Avista Energy Canada completed the sale of substantially all of their contracts and ongoing operations. Completion of this transaction will effectively end substantially all of the operations of this business segment.
- **Advantage IQ** – facility information and cost management services for multi-site customers. The activities of this business segment are conducted by Advantage IQ, Inc., an indirect subsidiary of Avista Corp.
- **Other** – includes sheet metal fabrication, venture fund investments and real estate investments. The activities of this business segment are conducted by various indirect subsidiaries of Avista Corp., including Advanced Manufacturing and Development (AM&D), doing business as METALfx.

Avista Energy, Advantage IQ and the various companies in the Other business segment are subsidiaries of Avista Capital, which is a direct, wholly owned subsidiary of Avista Corp. Our total common stockholders' equity was $926.6 million as of June 30, 2007, of which $230.3 million represented our investment in Avista Capital.

The following table presents net income (loss) for each of our business segments for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Avista Utilities	$ 17,257	$ 16,879	$ 37,184	$ 43,051
Energy Marketing and Resource Management	(3,938)	(4,610)	(11,561)	436
Advantage IQ	1,310	1,558	2,894	2,985
Other	(446)	(368)	(240)	(1,441)
Net income	$ 14,183	$ 13,459	$ 28,277	$ 45,031

Executive Level Summary

Overall

Our operating results and cash flows have been derived primarily from:

- regulated utility operations (Avista Utilities),
- energy trading, marketing and resource management activities (Avista Energy in the Energy Marketing and Resource Management segment), and
- Advantage IQ.

We intend to continue to focus on improving earnings and operating cash flows, controlling costs and reducing debt, while working to restore an investment grade credit rating.

On June 30, 2007, Avista Energy and Avista Energy Canada completed the sale of substantially all of their contracts and ongoing operations to Coral Energy Holding, L.P. (Coral Energy), as well as to certain other subsidiaries of Coral Energy. After closing costs and other adjustments, the transaction resulted in a pre-tax loss of $4.2 million. Proceeds from the transaction will include cash consideration for the net assets acquired by Coral Energy and liquidation of the net current assets of Avista Energy not sold to Coral Energy (primarily receivables, restricted cash and deposits with counterparties). Over time, we plan to redeploy the majority of the estimated $170 million of proceeds from the transaction into our regulated utility operations. Also, we have retained natural gas storage rights and facilities for the period subsequent to April 2011 and the power purchase agreement for the Lancaster Plant for the period 2010 through 2026. We plan to use these assets and contracts in our utility operations, subject to future regulatory approval.

Our net income was $14.2 million for the three months ended June 30, 2007 compared to $13.5 million for the three months ended June 30, 2006. This increase was primarily due to a decrease in the net loss for the Energy Marketing and Resource Management segment (Avista Energy) and an increase in net income at Avista Utilities, partially offset by lower earnings at Advantage IQ. Our net income was $28.3 million for the six months ended June 30, 2007 compared to $45.0 million for the six months ended June 30, 2006. This decrease was primarily due to a net loss at Avista Energy and lower earnings at Avista Utilities.

Avista Utilities

Avista Utilities is our most significant business segment. Our utility operating and financial performance is dependent upon, among other things:

- weather conditions,
- the price of natural gas in the wholesale market, including the effect on the price of fuel for generation,
- the price of electricity in the wholesale market, including the effects of weather conditions, natural gas prices and other factors affecting supply and demand, and
- regulatory decisions, allowing our utility to recover costs, including purchased power and fuel costs, on a timely basis, and to earn a fair return on investment.

Weather has a significant effect on our utility operations. Weather can impact customer demand and operating revenues and we normally have our highest retail (electric and natural gas) energy sales during the winter heating season in the first and fourth quarters of the year. We also have high electricity demand for air conditioning during the summer (third quarter). In general, warmer weather in the heating season and cooler weather in the cooling season will reduce operating revenues. In addition, a reduction in precipitation (particularly winter snowpack) can negatively impact electric resource costs by decreasing hydroelectric generation capability and increasing the costs for fuel to run thermal generation. This also increases the need for cash to purchase electric resources in the wholesale market. Regional precipitation and snowpack conditions typically have a significant effect on the wholesale price of electricity. In addition, high demand for electricity will generally increase the cost of fuel for electric generation and wholesale electric market prices.

Our hydroelectric generation was 104 percent of normal in 2006. For 2007, we are forecasting hydroelectric generation to be near normal. This 2007 forecast will be revised based on precipitation, temperatures and other variables during the remainder of the year.

We are subject to electric and natural gas commodity price risk. In general, price risk is the risk of fluctuation in the market price of the commodity needed, held or traded. Changes in energy commodity prices have a significant effect on our liquidity, as well as the market value of derivative assets and liabilities and unrealized gains and losses. Our utility operation has regulatory mechanisms in place that provide for the deferral and recovery of the majority of power and natural gas supply costs. However, if prices increase above the level currently recovered in retail rates during periods when we must purchase energy, power and natural gas deferral balances will increase. This would negatively affect operating cash flows and liquidity until such costs, with interest, are recovered from customers.

Our utility net income was $17.3 million for the three months ended June 30, 2007, an increase from $16.9 million for the three months ended June 30, 2006 primarily due to a decrease in interest expense and taxes other than income taxes. This was partially offset by a decrease in gross margin (operating revenues less resource costs) and an increase in other operating expenses. The decrease in gross margin was primarily due to the difference in electric resource costs as compared to the amount included in base retail rates. We recognized a benefit of $0.8 million under the Washington Energy Recovery Mechanism (ERM) for the three months ended June 30, 2007 compared to a benefit of $2.0 million under the ERM for the three months ended June 30, 2006. It is important to note that the amounts recognized under the ERM can vary significantly from quarter to quarter due to a variety of factors including changes in purchased power and fuel costs as well as the level of hydroelectric generation.

Our utility net income was $37.2 million for the six months ended June 30, 2007, a decrease from $43.1 million for the six months ended June 30, 2006 primarily due to a decrease in gross margin (operating revenues less resource costs). The decrease was also due to an increase in other operating expenses. This was partially offset by a decrease in interest expense. The decrease in gross margin was primarily due to the difference in electric resource costs as compared to the amount included in base retail rates. We recognized an expense of $2.4 million under the ERM for the six months ended June 30, 2007 compared to a benefit of $7.2 million under the ERM for the six months ended June 30, 2006.

We plan to continue to invest in generation, transmission and distribution systems with a focus on providing reliable service to our customers. Utility capital expenditures were $92.6 million for the six months ended June 30, 2007. We are expecting utility capital expenditures to be in the range of $180 to $190 million for 2007. Significant projects include the continued enhancement of our transmission system and upgrades to our generation facilities.

We are not expecting to receive any general rate increases in 2007 and we expect to absorb expenses under the ERM in 2007 as compared to a benefit in 2006. Based primarily on these factors, utility net income is likely to decrease for 2007 as compared to 2006. We filed a general rate case in Washington in April 2007 requesting rate increases averaging 15.9 percent for electric and 2.3 percent for natural gas. Any rate adjustments, if approved by the WUTC, would most likely become effective in early 2008.

Energy Marketing and Resource Management (Avista Energy)

On June 30, 2007 we sold substantially all of the contracts and ongoing operations of this business.

The historical activities of Avista Energy included:

- trading electricity and natural gas,
- the optimization of generation assets owned by other entities,
- long-term electric supply contracts,
- natural gas storage, and
- electric transmission and natural gas transportation arrangements.

Avista Energy Canada, Ltd. (Avista Energy Canada), a wholly owned subsidiary of Avista Energy, provided natural gas services to end-user industrial and commercial customers in British Columbia, Canada.

Our earnings and cash flows from this business segment have been by nature subject to significant variability because they are derived primarily from the day-to-day trading of electricity and natural gas and optimization of assets owned by other entities, rather than predictable long-term revenue streams. Also, these activities are for the most part subject to mark-to-market accounting. However, this is different from the required accounting for natural gas storage and certain other assets and contracts. As such, our earnings from Avista Energy have been subject to variability caused by the differences between the estimated market value and the required accounting for these assets and contracts.

Primarily through Avista Energy, we are involved in a number of legal and regulatory proceedings and complaints with respect to power markets in the western United States that remain unresolved. However, we believe that we have adequate reserves established for refunds that may be ordered. Any potential refunds or obligations arising from western power market issues (or any other contingent matters) have been retained by Avista Energy.

The Energy Marketing and Resource Management segment had a net loss of $3.9 million for the three months ended June 30, 2007 compared to a net loss of $4.6 million for the three months ended June 30, 2006. The difference between the estimated market value and the required accounting for certain contracts and physical assets under management increased the net loss by $2.9 million from this segment for the three months ended June 30, 2007 and reduced results by $7.9 million for the three months ended June 30, 2006.

The Energy Marketing and Resource Management segment had a net loss of $11.6 million for the six months ended June 30, 2007 compared to net income of $0.4 million for the six months ended June 30, 2006. The difference between the estimated market value and the required accounting for certain contracts and physical assets under management increased the net loss by $6.4 million from this segment for the six months ended June 30, 2007 and reduced net income by $5.3 million for the six months ended June 30, 2006.

The lower than expected results from this segment for both the second quarter and year-to-date 2007 were primarily due to:

- underperformance on the power side of the business,
- losses on the power purchase agreement for the Lancaster Plant,
- the difference between the estimated market value and the required accounting for certain contracts and physical assets under management, and
- a loss on the net assets sold to Coral Energy.

Advantage IQ

Our subsidiary, Advantage IQ, had net income of $1.3 million for the three months ended June 30, 2007, a decrease from $1.6 million for the three months ended June 30, 2006. Advantage IQ's net income was $2.9 million for the six months ended June 30, 2007, a decrease from $3.0 million for the six months ended June 30, 2006. The decrease for each period of 2007 as compared to 2006 was primarily due to an increase in operating expenses from expanding operations that included consulting services received in the second quarter, partially offset by increased operating revenues as a result of customer growth and an increase in interest earnings on funds held for customers.

We are implementing certain strategic investments at Advantage IQ aimed at creating long-term savings that will increase operating and capitalized costs in the short term. This will limit earnings growth from this segment in 2007 while enhancing the long-term profit potential of Advantage IQ.

Other Business Segment

Over time as opportunities arise, we plan to dispose of assets and phase out operations in the Other business segment. However, we may invest incremental funds in these businesses to protect existing investments. The net loss in our Other business segment was $0.4 million for the three months ended June 30, 2007 compared to a net loss of $0.4 million for the three months ended June 30, 2006. The net loss in our Other business segment was $0.2 million for the six months ended June 30, 2007 compared to a net loss of $1.4 million for the six months ended June 30, 2006. This improvement in results on a year-to-date basis was primarily due to net gains on certain long-term venture fund investments in 2007 as compared to net losses in 2006. We are not expecting a significant change in results from this business segment for second half of 2007 as compared to the second half of 2006.

Liquidity and Capital Resources

We have a committed line of credit in the total amount of $320.0 million with an expiration date of April 2011. There were $16.0 million of borrowings outstanding under the committed line of credit at June 30, 2007.

In March 2007, we amended our accounts receivable sales facility to extend the termination date to March 2008. Under this facility, we can sell without recourse, on a revolving basis, up to $85.0 million of accounts receivable.

Avista Energy had a $145.0 million committed line of credit that was terminated with the closing of the sale of substantially all of its contracts and ongoing operations to Coral Energy.

In December 2006, we entered into a sales agency agreement with a sales agent to issue up to 2 million shares of our common stock from time to time. Due to the proceeds from the sale and liquidation of Avista Energy's assets, we are not currently planning to issue any shares under this agreement.

For the remainder of 2007, we expect net cash flows from operating activities, proceeds from the sale and liquidation of Avista Energy's assets and our $320.0 million committed line of credit to provide adequate resources to fund:

- capital expenditures,
- maturing long-term debt and preferred stock,
- dividends, and
- other contractual commitments.

We have $358 million of long-term debt maturities and mandatory preferred stock redemptions in the remainder of 2007 and 2008. While proceeds from the Avista Energy transaction should reduce our funding needs, our forecasts indicate that we will need to issue new debt securities to fund a portion of these requirements in 2008.

Succession Planning

We have management succession plans that work towards ensuring that executive officer and key management positions can be appropriately filled as vacancies occur. We also have workforce development plans for key technical and craft areas.

Avista Utilities – Regulatory Matters

General Rate Cases

In recent years, we have generally not earned our authorized rates of return in our regulated utility operations. We regularly review the need for electric and natural gas rate changes in each state in which we provide service. We will continue to file for rate adjustments to:

- provide for recovery of operating costs and capital investments, and
- more closely align earned returns with those allowed by regulators.

With regards to the timing and plans for future filings, the assessment of our need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include in-service dates of major infrastructure investments and the timing of changes in major revenue and expense items. We are planning to file a natural gas general rate case in Oregon by the end of 2007.

We filed a general rate case in Washington in April 2007. In the general rate case, we have requested to increase electric rates for our Washington customers by an average of 15.9 percent, which is intended to increase annual revenues by $51.1 million. Approximately 40 percent of the increase in electric revenues would provide for an increased level of base power supply costs. A portion of these costs would otherwise be recovered through deferrals under the ERM and as such would not increase net income. We have also requested to increase natural gas rates by an average of 2.3 percent, which is intended to increase annual revenues by $4.5 million. Our request is based on a proposed rate of return of 9.39 percent with a common equity ratio of 47.8 percent and an 11.3 percent return on equity.

In our Washington general rate case filing, we have requested the establishment of a limited-scope proceeding called a Power Cost Only Rate Case. This process would allow us to file for an update to our base power supply and transmission-related revenues and expenses between general rate cases to provide more timely recovery of our costs.

In May 2007, the WUTC issued an order that consolidated our request for an accounting order regarding the accounting for debt repurchase costs into the general rate case filing. The current schedule from the WUTC anticipates an order in the general rate case on or before March 1, 2008.

The following is a summary of our authorized rates of return in each jurisdiction:

Jurisdiction and service	Implementation Date	Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
Washington electric and natural gas	January 2006	9.11%	10.40%	40%
Idaho electric and natural gas	September 2004	9.25%	10.40%	43%
Oregon natural gas	October 2003	8.88%	10.25%	48%

As part of the general rate case settlement agreement that was modified and approved by the WUTC Order in December 2005, we agreed to increase the utility equity component to 35 percent by the end of 2007 and 38 percent by the end of 2008. If we do not meet those targets, it could result in a reduction to base rates of 2 percent for each target. The calculation of the utility equity component is essentially the ratio of our total consolidated common equity to total capitalization excluding, in each case, our investment in Avista Capital. The utility equity component was 39.5 percent as of June 30, 2007. We should be able to meet these equity targets through expected earnings and proceeds from the Avista Energy transaction.

Oregon Senate Bill 408

The Public Utility Commission of Oregon (OPUC) issued final rules related to Oregon Senate Bill 408 (OSB 408). OSB 408 was enacted into law in 2005. These rules direct the utility to establish an automatic adjustment clause to account for the difference between income taxes collected in rates and taxes paid to units of government, net of adjustments, when that difference exceeds $100,000. The automatic adjustment clause may result in either rate increases or rate decreases and applies only to taxes paid and collected on or after January 1, 2006.

The final rules provide for an "apportionment method" that uses a three-factor formula consisting of property, payroll and sales for regulated operations of the utility in Oregon as the numerator, and these same factors for the consolidated company as the denominator, to determine the amount of consolidated taxes paid that are properly attributed to Oregon operations. Under the new rules, we will determine the least of:

- the properly attributed amount of taxes paid using the apportionment method,
- the amount of taxes determined on a stand-alone basis for Oregon operations, and
- total consolidated taxes paid.

We will then compare this amount to taxes collected in rates to determine if a refund or surcharge is required.

As required by OPUC orders, we (along with other utilities in Oregon) filed a private letter ruling request with the Internal Revenue Service in December 2006. The private letter ruling request seeks guidance on whether OSB 408 and the related OPUC orders violate normalization rules for accounting for income taxes. Based on an analysis of operating results for prior years and current rules, we recorded a liability for potential refunds to our customers of $1.3 million for 2006 and $0.7 million for the six months ended June 30, 2007.

Natural Gas Decoupling

In February 2007, the WUTC approved the implementation of a natural gas decoupling mechanism. Decoupling separates the direct link between natural gas sales volume and the recovery of the fixed cost of providing service to our customers. Because our rate structure provides for recovery of the majority of fixed costs on a per-therm (sales volume) basis, energy efficiency and conservation objectives have been directly at odds with the recovery of fixed costs, which do not vary with the volume of natural gas sold. Our decoupling mechanism should allow us to recover lost margin resulting from lower usage by Washington customers due to conservation and price elasticity. However, the mechanism will not provide rate adjustments related to abnormal weather. The decoupling mechanism is a three-year "pilot" that began in January 2007. A rate adjustment in any one year would be limited to no more than 2 percent. The filing of the first decoupling rate adjustment will be in the fall of 2007.

Accounting for Debt Repurchase Costs

The WUTC staff raised questions and requested information regarding our method of amortization of costs related to debt repurchased between 2002 and 2006. After discussions with the WUTC staff, we agree that the costs associated with debt repurchases beginning in 2002 should have been accounted for in accordance with FERC General Instruction 17 (FERC 17). In February 2007, we filed a request with the WUTC for an accounting order approving our current accounting treatment for debt repurchase costs. In May 2007, the WUTC issued an order that consolidated this issue into our April 2007 general rate case filing. In the April general rate case filing, we agreed that costs associated with any new repurchases of debt would be accounted for in accordance with FERC General Instruction 17 (FERC 17), and in the event we desire to account for the cost of new debt repurchases differently than prescribed in FERC 17, we would request an accounting order from the WUTC prior to the repurchase. Under FERC 17, debt repurchase costs are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs can be amortized over the life of the new debt. We have amortized debt repurchase costs over the average remaining maturity of outstanding debt and these costs are currently recovered through retail rates as a component of interest expense. In our request for an accounting order, we are not proposing to change the amortization method for debt repurchase costs incurred prior to December 31, 2006.

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used to track certain differences between actual power supply costs and the amount included in base retail rates for our Washington customers.

This difference in power supply costs primarily results from changes in:

- short-term wholesale market prices,
- the level of hydroelectric generation, and
- the level of thermal generation (including changes in fuel prices).

The initial amount of power supply costs in excess or below the level in retail rates, which we either incur the cost of, or receive the benefit from, is referred to as the deadband. The annual deadband amount is currently $4.0 million. We will incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. We will share annual power supply cost variances between $4.0 million and $10.0 million with customers. As such, 50 percent of the annual power supply cost variance in this range is deferred for future surcharge or rebate to customers and we will incur the cost of, or receive the benefit from, the remaining 50 percent. Once the annual power supply cost variance from the amount included in base rates exceeds $10.0 million, 90 percent of the cost variance is deferred for future surcharge or rebate. We will incur the cost of, or receive the benefit from, the remaining 10 percent of the annual variance beyond $10.0 million without affecting current or future customer rates.

The following is a summary of the ERM:

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
+/- $0 - $4 million	0%	100%
+/- between $4 million - $10 million	50%	50%
+/- excess over $10 million	90%	10%

Under the ERM, we make an annual filing on or before April 1st of each year to provide the opportunity for the WUTC and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. The ERM provides for a 90-day review period for the filing; however, the period may be extended by agreement of the parties or by WUTC order.

We have a Power Cost Adjustment (PCA) mechanism in Idaho that allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. In June 2007, the IPUC approved continuation of the PCA mechanism with the annual rate adjustment provision. The October 1 rate adjustments recover or rebate power costs that have been deferred during the preceding, July-June, twelve-month period. The PCA rate surcharge is currently 2.5 percent and, if approved by the IPUC, will increase to 4.7 percent on October 1, 2007.

The following table shows activity in deferred power costs for Washington and Idaho during the six months ended June 30, 2007 (dollars in thousands):

	Washington	Idaho	Total
Deferred power costs as of December 31, 2006	$ 70,159	$ 9,357	$ 79,516
Activity from January 1 – June 30, 2007:			
Power costs deferred	—	3,256	3,256
Interest and other net additions	1,564	361	1,925
Recovery of deferred power costs through retail rates	(15,884)	(2,400)	(18,284)
Deferred power costs as of June 30, 2007	$ 55,839	$ 10,574	$ 66,413

Purchased Gas Adjustments

Effective November 1, 2006, natural gas rates:

- increased 1.3 percent in Washington,
- decreased 3.4 percent in Idaho, and
- increased 6.9 percent in Oregon.

These natural gas rate increases and decreases are designed to pass through changes in purchased natural gas costs to our customers with no change in gross margin or net income. The increase in Oregon was approved subject to refund pending further review of our natural gas purchasing and hedging strategies. We have entered into a settlement agreement with the OPUC staff and the Northwest Industrial Gas Users related to this review, which was approved by the OPUC in May 2007. In Oregon, there is also an ongoing review of the PGA mechanism used by all natural gas distribution companies in Oregon (including Avista Corp.). The outcome of this review could impact our PGA mechanism and natural gas purchasing and hedging strategies in Oregon. Total deferred natural gas costs were $9.5 million as of June 30, 2007, a decrease from $18.3 million as of December 31, 2006 primarily due to recovery from customers during the first half of 2007.

Legal and Regulatory Proceedings in Western Power Markets

We are involved in a number of legal and regulatory proceedings and complaints with respect to power markets in the western United States. Most of these proceedings and complaints relate to the significant increase in the spot market price of energy in western power markets in 2000 and 2001, which allegedly contributed to or caused unjust and unreasonable prices. These proceedings and complaints include, but are not limited to:

- refund proceedings in California and the Pacific Northwest,
- market conduct investigations by the FERC, and
- complaints filed by various parties related to alleged misconduct by other parties in western power markets.

As a result of these proceedings and complaints, certain parties have asserted claims for refunds and damages from us (primarily through Avista Energy), which could result in a negative effect on future earnings. However, we believe that we have adequate reserves established for refunds that may be ordered. We have joined other parties in opposing these refund claims and complaints for damages. See further information in "Note 12 of the Notes to Consolidated Financial Statements." Any potential refunds or obligations arising from western power market issues (or any other contingent matters) have been retained by Avista Energy.

Results of Operations

The following provides an overview of changes in our Consolidated Statements of Income. More detailed explanations are provided, particularly for operating revenues and operating expenses in the business segment discussions (Avista Utilities, Energy Marketing and Resource Management, Advantage IQ and Other), that follow this section.

Three months ended June 30, 2007 compared to the three months ended June 30, 2006

Utility revenues increased $9.9 million to $268.0 million as a result of an increase in natural gas revenues of $18.6 million due to increased wholesale (primarily due to increased volumes) and retail (due to an increase in rates) natural gas sales. This was partially offset by decreased electric revenues of $8.7 million reflecting decreased sales of fuel and wholesale revenues.

Non-utility energy marketing and trading revenues increased $5.1 million to $19.4 million primarily due to a $6.9 million increase from sales of natural gas to commercial and industrial end-user customers (both through Avista Energy Canada and to Montana customers), partially offset by a decrease of $1.8 million in net trading margin on contracts accounted for under SFAS No. 133, as amended. This category of revenues, as well as non-utility resource costs, will decrease significantly in future periods with the sale of substantially all of Avista Energy's contracts and ongoing operations.

Other non-utility revenues increased $1.6 million to $16.6 million as a result of increased revenues from Advantage IQ of $1.9 million primarily due to customer growth, as well as an increase in interest earnings on funds held for customers. This was partially offset by decreased revenues from the Other business segment of $0.3 million primarily due to decreased sales at AM&D.

Utility resource costs increased $13.4 million as a result of an increase in natural gas resource costs of $19.2 million primarily due to an increase in the volume of natural gas purchases. The increase in natural gas resource costs was partially offset by a decrease in electric resource costs of $5.8 million reflecting a decrease in other fuel costs (economic sales of fuel that was not used in generation) and a change in deferred power costs. These decreases were partially offset by increased power purchased and fuel costs.

Utility other operating expenses increased $2.0 million primarily due to increased maintenance expenses, natural gas distribution expenses and outside services.

Utility depreciation and amortization increased $1.2 million primarily due to additions to utility plant. Utility plant in service has increased $104 million from June 30, 2006 to June 30, 2007.

Utility taxes other than income taxes decreased $3.3 million primarily due to decreased property taxes.

The net change in other non-utility operating expenses was an increase of $5.6 million due to:

- an increase of $3.6 million in the Energy Marketing and Resource Management segment due to the loss on the sale of contracts to Coral Energy, offset by decreased incentive compensation based on lower earnings,
- an increase of $2.1 million for Advantage IQ due to expanding operations and consulting services, and
- a decrease of $0.1 million in the Other business segment.

Interest expense decreased $2.0 million primarily due to our issuance of fixed rate long-term debt that replaced maturing debt (which had relatively high interest rates) in the fourth quarter of 2006.

Capitalized interest increased $0.6 million due to increased utility construction activity and the associated increase in construction work in progress balances.

Other income-net increased $1.5 million due to an increase in interest income, partially offset by a decrease in interest on power and natural gas deferrals.

Income taxes increased $0.9 million primarily due to increased income before income taxes and the tax effects of the sale of Avista Energy's contracts and ongoing operations to Coral Energy. Our effective tax rate was 38.3 percent for the three months ended June 30, 2007 compared to 36.9 percent for the three months ended June 30, 2006.

Six months ended June 30, 2007 compared to the six months ended June 30, 2006

Utility revenues increased $0.9 million to $682.3 million as a result of increased natural gas revenues of $41.4 million due to increased wholesale (primarily due to increased volumes) and retail (due to an increase in rates and volumes) natural gas sales. This was offset by a decrease in electric revenues of $40.5 million reflecting decreased wholesale revenues and sales of fuel, partially offset by increased retail revenues.

Non-utility energy marketing and trading revenues decreased $27.1 million to $48.8 million due to a decrease of $26.7 million in net trading margin on contracts accounted for under SFAS No. 133, as amended, and a $0.4 million decrease from sales of natural gas to commercial and industrial end-user customers (both through Avista Energy Canada and to Montana customers). This category of revenues will decrease significantly in future periods with the sale of substantially all of Avista Energy's contracts and ongoing operations.

Other non-utility revenues increased $2.7 million to $32.1 million as a result of increased revenues from Advantage IQ of $3.8 million primarily due to customer growth, as well as an increase in interest earnings on funds held for customers. This was partially offset by decreased revenues from the Other business segment of $1.0 million primarily due to decreased sales at AM&D.

Utility resource costs increased $11.8 million due to an increase in natural gas resource costs of $39.9 million primarily reflecting an increase in the volume of natural gas purchases. The increase in natural gas resource costs was partially offset by a decrease in electric resource costs of $28.1 million reflecting a decrease in other fuel costs (economic sales of fuel that was not used in generation) and a change in deferred power costs. These decreases are consistent with reduced resource optimization activities and lower sales of fuel and wholesale sales as part of the process of balancing loads and resources.

Utility other operating expenses increased $5.3 million primarily due to increased maintenance expenses, natural gas distribution expenses, compensation and benefits, outside services and the settlement of the shareholder litigation case.

Utility depreciation and amortization increased $1.3 million primarily due to additions to utility plant.

Utility taxes other than income taxes decreased $1.3 million primarily due to decreased property taxes, partially offset by increased retail electric and natural gas revenues and related taxes.

Non-utility resource costs decreased $12.2 million primarily due to decreased resource costs related to sales of natural gas to commercial and industrial end-user customers, and a change in natural gas inventory. This category of expenses will decrease significantly in future periods with the sale of substantially all of Avista Energy's contracts and ongoing operations.

The net change in other non-utility operating expenses was an increase of $6.4 million due to:

- an increase of $3.9 million in the Energy Marketing and Resource Management segment primarily due to the loss on the sale of contracts to Coral Energy,
- an increase of $3.8 million for Advantage IQ due to expanding operations, and
- a decrease of $1.3 million in the Other business segment due to lower operating expenses at AM&D and the accrual of an environmental liability at Avista Development during 2006.

Interest expense decreased $3.7 million primarily due to our issuance of fixed rate long-term debt that replaced maturing debt (which had relatively high interest rates) in the fourth quarter of 2006 and partially due to a decrease in interest expense on short-term borrowings under our committed line of credit.

Capitalized interest increased $1.2 million due to increased utility construction activity and the associated increase in construction work in progress balances.

Other income-net increased $2.7 million due to an increase in interest income and gains on long-term venture fund investments (Other segment), partially offset by a decrease in interest on power and natural gas deferrals.

Income taxes decreased $10.1 million primarily due to decreased income before income taxes, partially offset by the tax effects of Avista Energy's sale of contracts and ongoing operations to Coral Energy. Our effective tax rate was 36.5 percent for the six months ended June 30, 2007 compared to 36.9 percent for the six months ended June 30, 2006.

Avista Utilities

Three months ended June 30, 2007 compared to the three months ended June 30, 2006

Net income for the utility was $17.3 million for the three months ended June 30, 2007 compared to $16.9 million for the three months ended June 30, 2006. Utility income from operations was $45.9 million for the three months ended June 30, 2007 compared to $49.3 million for the three months ended June 30, 2006. This decrease in income from operations was primarily due to decreased gross margin (operating revenues less resource costs). The decrease was also due to an increase in other utility operating expenses (primarily maintenance expenses, natural gas distribution expenses and outside services). This was partially offset by a decrease in utility taxes other than income taxes (primarily due to decreased property taxes).

The following table presents our utility gross margin for the three months ended June 30 (dollars in thousands):

	Electric		Natural Gas		Total	
	2007	2006	2007	2006	2007	2006
Operating revenues	$ 163,809	$ 172,495	$ 104,188	$ 85,581	$ 267,997	$ 258,076
Resource costs	51,901	57,698	83,619	64,388	135,520	122,086
Gross margin	$ 111,908	$ 114,797	$ 20,569	$ 21,193	$ 132,477	$ 135,990

Utility operating revenues increased $9.9 million and utility resource costs increased $13.4 million, which resulted in a decrease of $3.5 million in gross margin. The gross margin on electric sales decreased $2.9 million and the gross margin on natural gas sales decreased $0.6 million. The decrease in our electric gross margin was partially due to the difference in electric resource costs as compared to the amount included in base retail rates resulting in the benefit of $0.8 million (of the $4.0 million deadband) of power supply costs in Washington during the second quarter of 2007. In the second quarter of 2006, we received a benefit of $2.0 million under the ERM. The increase in power supply costs for 2007 (as compared to the amount included in base rates) was primarily a result of lower hydroelectric generation, increased purchased power, higher fuel costs and greater use of our thermal generating resources (particularly Coyote Springs 2) to meet demand. The remaining decrease in electric gross margin and the decrease in natural gas gross margin were primarily due to a decrease in use per customer. This appears to be due to warmer than normal weather during the first half of the quarter and partially due to customer response to price increases, particularly with respect to the natural gas.

The following table presents our utility electric operating revenues and megawatt-hour (MWh) sales for the three months ended June 30 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2007	2006	2007	2006
Residential	$ 48,580	$ 48,184	734	738
Commercial	52,729	53,389	732	747
Industrial	23,936	23,501	526	520
Public street and highway lighting	1,367	1,320	7	6
Total retail	126,612	126,394	1,999	2,011
Wholesale	32,790	33,278	677	929
Sales of fuel	6	8,310	—	—
Other	4,401	4,513	—	—
Total	$ 163,809	$ 172,495	2,676	2,940

Retail electric revenues increased $0.2 million due to:

- an increase in revenue per MWh (increased revenues $1.0 million) due to a slight change in revenue mix, partially offset by
- a decrease in total MWhs sold (decreased revenues $0.8 million) primarily due to a decrease in use per customer.

Wholesale electric revenues decreased $0.5 million due to:

- a decrease in sales volumes (decreased revenues $12.2 million) consistent with decreased wholesale purchases and decreased resource optimization activities, partially offset by
- an increase in sales prices (increased revenues $11.7 million).

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market as sales of fuel. Sales of fuel decreased $8.3 million as almost all of our fuel purchases were used in generation.

The following table presents our utility natural gas operating revenues and therms delivered for the three months ended June 30 (dollars and therms in thousands):

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2007	2006	2007	2006
Residential	$ 38,579	$ 38,461	26,662	27,341
Commercial	22,527	22,138	17,951	17,729
Interruptible	1,268	1,039	1,245	979
Industrial	1,190	1,381	1,093	1,295
Total retail	63,564	63,019	46,951	47,344
Wholesale	37,757	19,682	56,198	35,663
Transportation	1,901	1,757	33,960	38,048
Other	966	1,123	64	95
Total	$ 104,188	$ 85,581	137,173	121,150

Natural gas revenues increased $18.6 million due to an increase in retail and wholesale natural gas revenues. The $0.5 million increase in retail natural gas revenues was due to higher retail rates (increased revenues $1.2 million), partially offset by a decrease in retail sales volumes (decreased revenues $0.7 million). We sold less retail natural gas in the second quarter of 2007 primarily due to a decrease in use per customer. The increase in our wholesale revenues of $18.1 million was due to an increase in volumes (increased revenues $13.8 million) and prices (increased revenues $4.3 million). Wholesale sales reflect the balancing of loads and resources and the sale of resources in excess of load requirements as part of the natural gas procurement process.

The following table presents our average number of electric and natural gas retail customers for the three months ended June 30:

	Electric Customers		Natural Gas Customers	
	2007	2006	2007	2006
Residential	305,383	299,582	272,546	266,645
Commercial	38,340	37,772	32,265	31,635
Interruptible	—	—	14	42
Industrial	1,370	1,390	260	252
Public street and highway lighting	425	433	—	—
Total retail customers	345,518	339,177	305,085	298,574

The following table presents our utility resource costs for the three months ended June 30 (dollars in thousands):

	2007	2006
Electric resource costs:		
Power purchased	$ 28,112	$ 23,972
Power cost amortizations, net of deferrals	8,366	16,397
Fuel for generation	12,239	7,714
Other fuel costs	23	7,931
Other regulatory amortizations, net	171	(1,037)
Other electric resource costs	2,990	2,721
Total electric resource costs	51,901	57,698
Natural gas resource costs:		
Natural gas purchased	81,821	58,231
Natural gas amortizations, net of deferrals	546	5,783
Other regulatory amortizations, net	1,252	374
Total natural gas resource costs	83,619	64,388

Total resource costs	$ 135,520	$ 122,086

Power purchased increased $4.1 million due to an increase in the price of power purchases (increased costs $7.8 million) due to overall increases in wholesale markets. This was partially offset by a decrease in the volume of purchases (decreased costs $3.7 million) consistent with lower wholesale sales volumes and decreased resource optimization activity as part of the balancing of loads and resources.

Net amortization of deferred power costs was $8.4 million for the three months ended June 30, 2007 compared to $16.4 million for the three months ended June 30, 2006. During the second quarter of 2007, we recovered (collected as revenue) $6.7 million of previously deferred power costs in Washington and $1.1 million in Idaho. During the second quarter of 2007, we deferred $0.5 million of power costs in Idaho below the amount included in base retail rates. We did not defer any power costs in Washington during the second quarter of 2007, as power supply costs were within the $4.0 million deadband under the ERM.

Fuel for generation increased $4.5 million primarily due to higher natural gas fuel prices and an increase in thermal generation volumes.

Other fuel costs decreased $7.9 million. This represents fuel that was purchased for generation, but was later sold when conditions indicated that it was not economic to use the fuel in generation as part of the resource optimization process. The associated revenues are reflected as sales of fuel. Other fuel costs exceeded revenues we received from selling the natural gas. We account for this shortfall under the ERM in Washington and the PCA in Idaho. The decrease in other fuel costs was primarily due to almost all of our fuel purchases being used as fuel for generation.

The expense for natural gas purchased for sale to customers increased $23.6 million primarily due to an increase in total therms purchased. This was primarily due to an increase in wholesale sales as part of the balancing of loads and resources as part of the natural gas procurement process. The increase was also partially due to an increase natural gas prices. During the second quarter of 2007, we amortized $0.5 million of deferred natural gas costs compared to $5.8 million for the second quarter of 2006.

Six months ended June 30, 2007 compared to the six months ended June 30, 2006

Net income for the utility was $37.2 million for the six months ended June 30, 2007 compared to $43.1 million for the six months ended June 30, 2006. Utility income from operations was $96.1 million for the six months ended June 30, 2007 compared to $112.3 million for the six months ended June 30, 2006. This decrease in income from operations was primarily due to decreased gross margin (operating revenues less resource costs). The decrease was also due to an increase in other utility operating expenses (primarily maintenance expenses, natural gas distribution expenses, compensation and benefits, outside services and the settlement of the shareholder litigation case). This was partially offset by a decrease in utility taxes other than income taxes (primarily due to decreased property taxes, partially offset by increased revenue related taxes).

The following table presents our utility gross margin for the six months ended June 30 (dollars in thousands):

	Electric		Natural Gas		Total	
	2007	2006	2007	2006	2007	2006
Operating revenues	$ 353,977	$ 394,502	$ 328,286	$ 286,864	$ 682,263	$ 681,366
Resource costs	143,965	172,102	261,541	221,589	405,506	393,691
Gross margin	$ 210,012	$ 222,400	$ 66,745	$ 65,275	$ 276,757	$ 287,675

Utility operating revenues increased $0.9 million and utility resource costs increased $11.8 million, which resulted in a decrease of $10.9 million in gross margin. The gross margin on electric sales decreased $12.4 million and the gross margin on natural gas sales increased $1.5 million. The decrease in our electric gross margin was primarily due to the difference in electric resource costs as compared to the amount included in base retail rates resulting in the expense of $2.4 million (of the $4.0 million deadband) of power supply costs in Washington during the first half of 2007. We received a benefit of $7.2 million under the ERM in the first half of 2006. The increase in power supply costs for 2007 (as compared to the amount included in base rates) was primarily due to lower hydroelectric generation (second quarter), higher fuel costs and greater use of our thermal generating resources (particularly Coyote Springs 2). The increase in natural gas gross margin was primarily due to colder weather in the first quarter of 2007 and customer growth.

The following table presents our utility electric operating revenues and megawatt-hour (MWh) sales for the six months ended June 30 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2007	2006	2007	2006
Residential	$ 121,676	$ 116,931	1,841	1,780
Commercial	107,840	105,983	1,503	1,482
Industrial	46,183	46,275	1,019	1,029
Public street and highway lighting	2,773	2,599	13	12
Total retail	278,472	271,788	4,376	4,303
Wholesale	59,098	72,429	1,019	1,404
Sales of fuel	8,149	39,247	—	—
Other	8,258	11,038	—	—
Total	$ 353,977	$ 394,502	5,395	5,707

Retail electric revenues increased $6.7 million due to an increase in:

- total MWhs sold (increased revenues $4.7 million) primarily due to customer growth and partially due to an increase in use per customer, and
- revenue per MWh (increased revenues $2.0 million) due to a slight change in revenue mix with a lower percentage of industrial sales.

The increase in use per customer was primarily due to colder weather in the first quarter.

Wholesale electric revenues decreased $13.3 million due to:

- a decrease in sales volumes (decreased revenues $22.3 million) consistent with decreased wholesale purchases and decreased resource optimization activities, partially offset by
- an increase in sales prices (increased revenues $9.0 million).

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market as sales of fuel. Sales of fuel decreased $31.1 million as a greater percentage of our fuel purchases were used in generation.

Other electric revenues decreased $2.8 million primarily due to revenues of $3.0 million from the sale of claims we had against Enron Corporation and certain of its affiliates received in 2006 (first quarter), partially offset by increased transmission revenues.

The following table presents our utility natural gas operating revenues and therms delivered for the six months ended June 30 (dollars and therms in thousands):

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2007	2006	2007	2006
Residential	$ 151,118	$ 143,594	110,525	108,403
Commercial	83,905	80,231	67,759	66,452
Interruptible	2,856	2,747	2,806	2,652
Industrial	3,258	3,408	2,974	3,171
Total retail	241,137	229,980	184,064	180,678
Wholesale	81,291	50,897	121,660	81,557
Transportation	3,576	3,365	77,765	80,231
Other	2,282	2,622	303	308
Total	$ 328,286	$ 286,864	383,792	342,774

Natural gas revenues increased $41.4 million due to an increase in retail and wholesale natural gas revenues. The $11.2 million increase in retail natural gas revenues was due to higher retail rates (increased revenues $6.7 million) and increased volumes (increased revenues $4.5 million). We sold more retail natural gas in the first half of 2007 primarily due to an increase in use per customer (due to colder weather in the first quarter) and customer growth. The increase in our wholesale revenues of $30.4 million was due to an increase in volumes (increased revenues $26.8 million) and an increase in prices (increased revenues $3.6 million). Wholesale sales reflect the balancing of loads and resources and the sale of resources in excess of load requirements as part of the natural gas procurement process.

The following table presents our average number of electric and natural gas retail customers for the six months ended June 30:

	Electric Customers		Natural Gas Customers	
	2007	2006	2007	2006
Residential	305,556	299,537	272,828	266,547
Commercial	38,337	37,784	32,242	31,680
Interruptible	—	—	40	41
Industrial	1,369	1,392	259	256
Public street and highway lighting	425	431	—	—
Total retail customers	345,687	339,144	305,369	298,524

The following table presents our utility resource costs for the six months ended June 30 (dollars in thousands):

	2007	2006
Electric resource costs:		
Power purchased	$ 67,991	$ 67,890
Power cost amortizations, net of deferrals	15,028	26,576
Fuel for generation	46,370	33,041
Other fuel costs	10,919	42,388
Other regulatory amortizations, net	(2,183)	(3,070)
Other electric resource costs	5,840	5,277
Total electric resource costs	143,965	172,102
Natural gas resource costs:		
Natural gas purchased	248,160	204,974
Natural gas amortizations, net of deferrals	9,036	15,246
Other regulatory amortizations, net	4,345	1,369
Total natural gas resource costs	261,541	221,589
Total resource costs	$ 405,506	$ 393,691

Power purchased increased $0.1 million due to an increase in the price of power purchases (increased costs $13.1 million) due to overall increases in wholesale markets. This was mostly offset by a decrease in the volume of power purchases (decreased costs $13.0 million) primarily due to increased thermal generation as well as decreased resource optimization activities as part of the process of balancing loads and resources. This was consistent with a decrease in wholesale sales.

Net amortization of deferred power costs was $15.0 million for the six months ended June 30, 2007 compared to $26.6 million for the six months ended June 30, 2006. During the first half of 2007, we recovered (collected as revenue) $15.9 million of previously deferred power costs in Washington and $2.4 million in Idaho. During the first half of 2007, we deferred $3.3 million of power costs in Idaho above the amount included in base retail rates. We did not defer any power costs in Washington during the first half of 2007, as power supply costs were within the $4.0 million deadband under the ERM.

Fuel for generation increased $13.3 million due to higher natural gas fuel prices and an increase in thermal generation volumes (particularly Coyote Springs 2).

Other fuel costs decreased $31.5 million. This represents fuel that was purchased for generation, but was later sold when conditions indicated that it was not economic to use the fuel in generation as part of the resource optimization process. The associated revenues are reflected as sales of fuel. Other fuel costs exceeded revenues we received from selling the natural gas. We account for this shortfall under the ERM in Washington and the PCA in Idaho. The decrease in other fuel costs was primarily due to an increased percentage of fuel used in generation.

The expense for natural gas purchased for sale to customers increased $43.2 million primarily due to an increase in total therms purchased. This was primarily due to an increase in wholesale sales as part of the balancing of loads and resources as part of the natural gas procurement process, and partially due to an increase in retail sales volumes. The increase was also partially due to an increase natural gas prices. During the first half of 2007, we amortized $9.0 million of deferred natural gas costs compared to $15.2 million for the first half of 2006.

Energy Marketing and Resource Management

The Energy Marketing and Resource Management segment primarily includes the results of Avista Energy. On June 30, 2007, Avista Energy completed the sale of substantially all of its contracts and ongoing operations. Completion of this transaction effectively ends substantially all of the operations of this business segment.

Historical earnings from Avista Energy were derived from the following activities:

- taking speculative positions on future price movements within established risk management policies,
- optimizing generation assets owned by other entities,
- capturing price differences between commodities (spark spread) by converting natural gas into electricity through the power generation process,
- purchasing and storing natural gas for later sales to seek gains from seasonal price variations and demand peaks,
- transmitting electricity and transporting natural gas between locations, including moving energy from lower priced/demand regions to higher priced/demand markets and hub locations, and
- marketing natural gas to end-user industrial and commercial customers.

Avista Energy reports the net margin on derivative commodity instruments held for trading as operating revenues. Revenues from contracts that are not derivatives under SFAS No. 133 and derivative commodity instruments not held for trading are reported on a gross basis in operating revenues. Costs from contracts that are not derivatives under SFAS No. 133 and derivative commodity instruments not held for trading, are reported on a gross basis in resource costs.

The following table presents our net realized gains and net unrealized losses from Avista Energy for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2007	**2006**	**2007**	**2006**
Net realized gains	$ 4,673	$ 12,197	$ 17,288	$ 17,472
Net unrealized losses	(3,661)	(16,078)	(24,594)	(9,938)
Total gross margin (operating revenues less resource costs)	$ 1,012	$ (3,881)	$ (7,306)	$ 7,534

Differences in the estimated market value and the required accounting for certain contracts and physical assets under management

Earnings from this segment were affected by the variability associated with the difference between the estimated market value and the required accounting for certain contracts and physical assets under management of Avista Energy. These operations were managed on an economic basis reflecting contracts and assets under management at estimated market value. Under SFAS No. 133, certain contracts, which are considered derivatives, economically hedge other contracts and physical assets under management, which are not considered derivatives. Derivative contracts are generally recorded at estimated market value. Non-derivative contracts are generally accounted for at the lower of cost or market value. The accounting treatment does not affect the underlying cash flows or economics of our transactions. This difference between the estimated market value and the required accounting are generally reversed in future periods when market values change or when our contracts are settled or realized. However, the amount of the difference could increase or decrease prior to settlement due to changes in forward market prices. This primarily related to Avista Energy's management of natural gas inventory and its control of natural gas-fired generation through a power purchase agreement related to the Lancaster Plant.

Analysis of operating revenues, resource costs and gross margin for the three months ended June 30, 2007 compared to the three months ended June 30, 2006

Operating revenues increased $5.1 million to $19.4 million due to a $6.9 million increase from sales of natural gas to commercial and industrial end-user customers (both through Avista Energy Canada and to Montana customers), partially offset by a decrease of $1.8 million in net trading margin on contracts accounted for under SFAS No. 133, as amended.

Resource costs increased $0.2 million primarily due to decreased resource costs related to sales of natural gas to commercial and industrial end-user customers, partially offset by a change in natural gas inventory.

Our gross margin (operating revenues less resource costs) from Avista Energy was a gain of $1.0 million for the three months ended June 30, 2007 compared to a loss of $3.9 million for the three months ended June 30, 2006. The improvement was primarily due to the difference between the estimated market value and the required accounting for certain contracts and physical assets under management. This reduced gross margin by $4.4 million for the three months ended June 30, 2007 and $12.2 million for the three months ended June 30, 2006.

Our net realized gains from Avista Energy decreased to $4.7 million for the three months ended June 30, 2007 from $12.2 million for the three months ended June 30, 2006. The decrease in net realized gains was primarily due to decreased net gains on physical electric transactions and increased net losses on physical natural gas transactions. These decreases were partially offset by the change in natural gas inventory.

Our total mark-to-market adjustment from this segment was a net unrealized loss of $3.7 million for the three months ended June 30, 2007 compared to a net unrealized loss of $16.1 million for the three months ended June 30, 2006. This change was primarily due to the difference between the estimated market value and the required accounting for certain contracts and physical assets under management as described above.

Analysis of operating revenues, resource costs and gross margin for the six months ended June 30, 2007 compared to the six months ended June 30, 2006

Operating revenues decreased $27.1 million to $48.8 million due to a decrease of $26.7 million in net trading margin on contracts accounted for under SFAS No. 133, as amended, and a $0.4 million decrease from sales of natural gas to commercial and industrial end-user customers (both through Avista Energy Canada and to Montana customers).

Resource costs decreased $12.2 million primarily due to decreased resource costs related to sales of natural gas to commercial and industrial end-user customers, and a change in natural gas inventory.

Our gross margin (operating revenues less resource costs) from Avista Energy was a loss of $7.3 million for the six months ended June 30, 2007 compared to a gain of $7.5 million for the six months ended June 30, 2006. The decrease was primarily due to underperformance on the power side of the business, losses on the power purchase agreement for the Lancaster Plant, and the difference between the estimated market value and the required accounting for certain contracts and physical assets under management.

Our net realized gains from Avista Energy were $17.3 million for the six months ended June 30, 2007, as compared to $17.5 million for the six months ended June 30, 2006. Net gains on physical electric transactions decreased and net losses on physical natural gas transactions increased. This was partially offset by increased net gains on settled financial transactions and decreased transmission and transportation fees.

Our total mark-to-market adjustment from this segment was a net unrealized loss of $24.6 million for the six months ended June 30, 2007 compared to a net unrealized loss of $9.9 million for the six months ended June 30, 2006.

Energy trading activities and positions

The following table summarizes information for trading activities at Avista Energy during the six months ended June 30, 2007 (dollars in thousands):

	Electric Assets net of Liabilities	Natural Gas Assets net of Liabilities	Total Unrealized Gain (Loss)
Fair value of contracts as of December 31, 2006	$ 34,044	$ (507)	$ 33,537
Less contracts settled during 2007 (1)	(25,080)	7,792	(17,288)
Less contracts sold to Coral Energy (2)	(13,571)	5,670	(7,901)
Fair value of new contracts when entered into during 2007 (3)	—	—	—
Change in fair value due to changes in valuation techniques (4)	—	—	—
Change in fair value attributable to market prices and other market changes	4,607	(12,955)	(8,348)
Fair value of contracts as of June 30, 2007	$ —	$ —	$ —

(1) Contracts settled during 2007 include those contracts that were open in 2006 but settled during the six months ended June 30, 2007 as well as new contracts entered into and settled during 2007. Amount represents net realized gains associated with these settled transactions.

(2) Represents the estimated fair value of the contracts sold to Coral Energy on June 30, 2007.

(3) We did not enter into any origination transactions during the six months ended June 30, 2007 in which we recognized any dealer profit or mark-to-market gain or loss at inception.

(4) During the six months ended June 30, 2007, we did not experience a change in fair value due to changes in valuation techniques.

Advantage IQ

Three months ended June 30, 2007 compared to the three months ended June 30, 2006

Net income for Advantage IQ was $1.3 million for the three months ended June 30, 2007 compared to $1.6 million for the three months ended June 30, 2006. Operating revenues increased $1.9 million and operating expenses increased $2.2 million. The increase in operating revenues was primarily due to the expansion of Advantage IQ's customer base as well as an increase in interest earnings on funds held for customers. The increase in interest earnings on funds held for customers was due in part to an increase in interest rates. The increase in operating expenses primarily reflects increased labor and other operational costs necessary to serve an expanding customer base, which included fees for consulting services in the second quarter of 2007.

Six months ended June 30, 2007 compared to the six months ended June 30, 2006

Net income for Advantage IQ was $2.9 million for the six months ended June 30, 2007 compared to $3.0 million for the six months ended June 30, 2006. Operating revenues increased $3.8 million and operating expenses increased $4.0 million. The increase in operating revenues was primarily due to the expansion of Advantage IQ's customer base as well as an increase in interest earnings on funds held for customers. Advantage IQ has over 385 customers representing 227,000 billed sites in North America. The number of billed sites increased by 36,000, or 19 percent, from June 30, 2006. The increase in operating expenses primarily reflects increased labor and other operational costs necessary to serve an expanding customer base.

Other Business Segment

Three months ended June 30, 2007 compared to the three months ended June 30, 2006

The net loss from this business segment was $0.4 million for the three months ended June 30, 2007 consistent with a net loss of $0.4 million for the three months ended June 30, 2006. Operating revenues decreased $0.3 million and operating expenses decreased $0.3 million.

Six months ended June 30, 2007 compared to the six months ended June 30, 2006

The net loss from this business segment was $0.2 million for the six months ended June 30, 2007 compared to a net loss of $1.4 million for the six months ended June 30, 2006. Operating revenues decreased $1.0 million and operating expenses decreased $1.5 million. Net income for AM&D was $0.2 million for the first half of 2007 consistent with $0.2 million for the first half of 2006. With respect to overall segment results, the improvement was due to:

- the accrual for an environmental liability in 2006, and
- gains on certain long-term venture fund investments in this segment in 2007 compared to losses in 2006.

New Accounting Standards

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109," (FIN 48) which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. We adopted FIN 48 in the first quarter of 2007. The adoption of FIN 48 did not have a cumulative effect on our financial condition and results of operations. See Notes 2 and 8 of the Notes to Consolidated Financial Statements for further information.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which provides enhanced guidance for using fair value to measure assets and liabilities. We will be required to adopt SFAS No. 157 in 2008. We are evaluating the impact SFAS No. 157 will have on our financial condition and results of operations.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." This statement permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected would be reported in net income. We will be required to adopt SFAS No. 159 in 2008. We are evaluating the impact SFAS No. 159 will have on our financial condition and results of operations.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires us to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on our consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein. Our critical accounting policies that require the use of estimates and assumptions were discussed in detail in the 2006 Form 10-K and have not changed materially from that discussion with the exception of "Avista Energy Revenues and Trading Activities," which will no longer be a critical accounting policy due to the sale of substantially all of Avista Energy's contracts and ongoing operations.

Liquidity and Capital Resources

Review of Cash Flow Statement

Overall During the six months ended June 30, 2007, positive cash flows from operating activities of $158.0 million were used to fund the majority of our cash requirements. These cash requirements included utility property capital expenditures of $92.6 million, debt maturities of $12.3 million and dividends of $15.6 million. As cash flows from operating activities and other sources of cash inflows exceeded other funding requirements, our total cash and cash equivalents increased $75.1 million during the first half of 2007. This was primarily due to the liquidation of restricted cash and deposits with counterparties at Avista Energy.

Operating Activities Net cash provided by operating activities was $158.0 million for the six months ended June 30, 2007 compared to $161.9 million for the six months ended June 30, 2006. Net cash provided by working capital components was $49.8 million for the six months ended June 30, 2007, compared to $42.8 million for the six months ended June 30, 2006. The net cash provided during the six months ended June 30, 2007 primarily reflects positive cash flows from:

- accounts receivable (representing net cash received from our customers),
- deposits with counterparties (representing the return from counterparties of cash posted as collateral at Avista Energy), and
- deposits from counterparties (representing cash received as collateral funds from counterparties at Avista Utilities).

This cash provided was partially offset by negative cash flows from accounts payable (representing net cash paid to our vendors).

The net cash provided during the six months ended June 30, 2006 primarily reflects positive cash flows from:

- accounts receivable (representing net cash received from customers),
- other current liabilities (primarily due to an increase in customer fund obligations at Advantage IQ), and
- cash deposits from counterparties (representing cash received as collateral funds from counterparties).

These positive cash flows were partially offset by a decrease in accounts payable (representing net cash paid to vendors) and other current assets (primarily due to an increase in funds held for customers at Advantage IQ).

Significant non-cash items included $23.6 million of power and natural gas cost amortizations, net of deferrals, for the first half of 2007, a decrease from $41.4 million for the first half of 2006 primarily due to a decrease in recoveries of previously deferred costs from customers. Significant changes in non-cash items also included a $14.7 million change in the unrealized loss on energy commodity derivatives, representing the change to an unrealized loss of $24.6 million on energy trading activities for the first half of 2007 as compared to an unrealized loss of $9.9 million for the first half of 2006.

Investing Activities Net cash used in investing activities was $71.0 million for the six months ended June 30, 2007, a decrease compared to $78.2 million for the six months ended June 30, 2006. This decrease was due to a change in restricted cash. We liquidated $26.3 million of restricted cash in the first half of 2007 representing the return of cash collateralizing energy contracts at Avista Energy and interest rate swap agreements at Avista Corp. This was partially offset by an increase in utility property capital expenditures in 2007 and other cash inflows in the first half of 2006, which included the receipt of $5.5 million from our sale of a claim against an affiliate of Enron Corporation related to the construction of Coyote Springs 2 and proceeds from asset sales of $7.7 million (primarily for a turbine at Avista Power).

Financing Activities Net cash used in financing activities was $12.0 million for the six months ended June 30, 2007 compared to $73.8 million for the six months ended June 30, 2006. During the first half of 2007, our short-term borrowings increased $12.0 million, which reflects an increase in the amount of debt outstanding under our $320.0 million committed line of credit. Cash dividends paid increased to $15.6 million (or 29.5 cents per share) for the first half of 2007 from $13.7 million (or 28 cents per share) for the first half of 2006. Debt maturities were $12.3 million for the first half of 2007.

During the six months ended June 30, 2006, short-term borrowings decreased $56.5 million, which reflected a decrease in the amount of debt outstanding under our line of credit.

Overall Liquidity

Our consolidated operating cash flows have been primarily derived from the operations of Avista Utilities and Avista Energy. The primary source of operating cash flows for our utility operations is revenues (including the recovery of previously deferred power and natural gas costs) from sales of electricity and natural gas. Significant uses of cash flows from our utility operations include the purchase of electricity and natural gas, and payment of other operating expenses, taxes and interest, with any excess being available for other corporate uses such as capital expenditures and dividends. The primary source and use of operating cash flows for Avista Energy was revenues and costs from realized energy commodity transactions as well as cash collateral deposited to or held from counterparties. Significant operating cash outflows for Avista Energy also included other operating expenses and taxes.

On June 30, 2007, Avista Energy completed the sale of substantially all of its contracts and ongoing operations to Coral Energy. Proceeds from the sale of Avista Energy's net assets to Coral Energy and liquidation of Avista Energy's remaining net current assets (primarily receivables, restricted cash and deposits with counterparties) are expected to total approximately $170 million to be received in the third quarter of 2007. Over time, we plan to redeploy the majority of the proceeds from the transaction into our regulated utility operations.

Over time, our operating cash flows usually do not fully support the needs for utility capital expenditures. As such, from time to time, we may need to access capital markets in order to fund these needs as well as fund maturing debt. See further discussion at "Capital Resources."

We design operating and capital budgets to control operating costs and capital expenditures, particularly for our regulated utility operations. In addition to operating expenses, we have continuing commitments for capital expenditures for construction, improvement and maintenance of utility facilities.

We will continue to periodically file for rate adjustments for recovery of operating costs and capital investments to provide the opportunity to align our earned returns with those allowed by regulators. We filed a general rate case in Washington in April 2007 requesting general rate increases averaging 15.9 percent for electric and 2.3 percent for natural gas. This is designed to increase annual electric revenues by $51.1 million and annual natural gas revenues by $4.5 million. See further details in the section "Avista Utilities – Regulatory Matters."

With respect to our utility operations, when power and natural gas costs exceed the levels currently recovered from retail customers, net cash flows are negatively affected. Factors that could cause purchased power costs to exceed the levels currently recovered from our customers include, but are not limited to, higher prices in wholesale markets when we are buying energy or an increased need to purchase power in the wholesale markets. Factors beyond our control that could result in an increased need to purchase power in the wholesale markets include, but are not limited to:

- increases in demand (either due to weather or customer growth),
- low availability of streamflows for hydroelectric generation,
- outages at generating facilities, and
- failure of third parties to deliver on energy or capacity contracts.

Our hydroelectric generation was 104 percent of normal in 2006. For 2007, we are forecasting hydroelectric generation to be near normal. This 2007 forecast will change based upon precipitation, temperatures and other variables during the remainder of the year.

We monitor the potential liquidity impacts of increasing energy commodity prices for our utility operations. We believe that we have adequate liquidity to meet the increased cash needs of higher energy commodity prices through our:

- current cash and cash equivalents, and
- $320.0 million committed line of credit.

Our utility has regulatory mechanisms in place that provide for the deferral and recovery of the majority of power and natural gas supply costs. However, if prices increase, deferral balances will increase, which will negatively affect our cash flow and liquidity until such costs, with interest, are recovered from customers.

Capital Resources

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings, consisted of the following as of June 30, 2007 and December 31, 2006 (dollars in thousands):

	June 30, 2007		December 31, 2006	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 307,720	15.1%	$ 26,605	1.3%
Short-term borrowings	16,000	0.8	4,000	0.2
Long-term debt to affiliated trusts	113,403	5.5	113,403	5.6
Long-term debt	655,377	32.0	949,854	46.7
Total debt	1,092,500	53.4	1,093,862	53.8
Preferred stock-cumulative (including current portion)	26,250	1.3	26,250	1.3
Total liabilities	1,118,750	54.7	1,120,112	55.1
Stockholders' equity	926,590	45.3	914,525	44.9
Total	$ 2,045,340	100.0%	$ 2,034,637	100.0%

We need to finance capital expenditures and obtain additional working capital from time to time. The cash requirements needed to service our indebtedness, both short-term and long-term, reduces the amount of cash flow available to fund working capital, purchased power and natural gas costs, capital expenditures, dividends and other requirements. Our stockholders' equity increased $12.1 million during the first half of 2007 primarily due to net income and other comprehensive income, partially offset by dividends.

We generally fund capital expenditures with a combination of internally generated cash and external financing. The level of cash generated internally and the amount that is available for capital expenditures fluctuates depending on a variety of factors. Cash provided by our utility operating activities and cash generated by the Avista Energy transaction (including the sale of net assets to Coral Energy and liquidation of net current assets not sold to Coral Energy) are expected to be the primary sources of funds for operating needs, dividends, capital expenditures, as well as maturing long-term debt and preferred stock for 2007. Borrowings under our $320.0 million committed line of credit may supplement these funds to the extent necessary.

We have $358 million of long-term debt maturities and mandatory preferred stock redemptions in the remainder of 2007 and 2008. While proceeds from the Avista Energy transaction should reduce our funding needs, our forecasts indicate that we will need to issue new debt securities to fund a portion of these requirements in 2008. In 2004, we entered into forward-starting interest rate swap agreements effectively locking in market fixed interest rates, which were relatively low compared to historical interest rates, for $125 million of our forecasted debt issuances in 2008.

We have a $320.0 million committed line of credit agreement with various banks with an expiration date of April 5, 2011. Under the agreement, we can request the issuance of up to $320.0 million in letters of credit. As of June 30, 2007, we had $16.0 million in borrowings outstanding, an increase from $4.0 million as of December 31, 2006. As of June 30, 2007, there were $44.3 million in letters of credit outstanding, a decrease from $77.1 million as of December 31, 2006. The committed line of credit is secured by $320.0 million of non-transferable First Mortgage Bonds issued to the agent bank. Such First Mortgage Bonds would only become due and payable in the event, and then only to the extent, that we default on obligations under the committed line of credit.

Our committed line of credit agreement contains customary covenants and default provisions, including a covenant requiring the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Utilities for the preceding twelve-month period at the end of any fiscal quarter to be greater than 1.6 to 1. As of June 30, 2007, we were in compliance with this covenant with a ratio of 2.50 to 1. The committed line of credit agreement also has a covenant which does not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 70 percent at the end of any fiscal quarter. This ratio limitation will be increased to 75 percent during the period between the completion of the proposed change in our corporate organization (see Note 13) and December 31, 2007. As of June 30, 2007, we were in compliance with this covenant with a ratio of 53.4 percent. If the proposed change in organization becomes effective, the committed line of credit agreement will remain at Avista Corp. (Avista Utilities).

Any default on the line of credit or other financing arrangements of Avista Corp. or any of our significant subsidiaries could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Any defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock. We do not guarantee the indebtedness of any of our subsidiaries. As of June 30, 2007, Avista Corp. and our subsidiaries were in compliance with all of the covenants of our financing agreements.

In December 2005, the WUTC issued an order approving the settlement agreement reached in our Washington general rate case with certain conditions. We agreed to increase the utility equity component to 35 percent by the end of 2007 and to 38 percent by the end of 2008. As further discussed at "Note 13 of the Notes to the Consolidated Financial Statements," the IPUC accepted a stipulation that we entered with the IPUC Staff that sets forth a variety of conditions related to the implementation of our holding company structure. One of the conditions provides for the same utility equity components that are required in our January 2006 Washington general rate case. If we do not meet those targets, it could result in a reduction in base rates of 2 percent for each target in each of Washington and Idaho. We have also entered into a settlement agreement in Washington related to our proposed holding company formation. In this settlement agreement, we have committed to increase the utility equity component to 40 percent by June 30, 2008. However, the provision to reduce base rates by 2 percent does not apply if we fail to meet this target. The utility equity component was 39.5 percent as of June 30, 2007. We should be able to meet these equity targets through expected earnings and proceeds from the Avista Energy transaction.

In December 2006, we entered into a sales agency agreement with a sales agent to issue up to 2 million shares of our common stock from time to time. Due to the proceeds from the sale and liquidation of Avista Energy's assets, we are not currently planning to issue any shares under this agreement.

Off-Balance Sheet Arrangements

Avista Receivables Corporation (ARC) is our wholly owned, bankruptcy-remote subsidiary formed for the purpose of acquiring or purchasing interests in certain of our accounts receivable, both billed and unbilled. On March 19, 2007, Avista Corp., ARC and a third-party financial institution amended a Receivables Purchase Agreement. The most significant amendment was to extend the termination date from March 20, 2007 to March 17, 2008. The Receivables Purchase Agreement was originally entered into on May 29, 2002 and provides us with cost-effective funds for:

- working capital requirements,
- capital expenditures, and
- other general corporate needs.

Under the Receivables Purchase Agreement, ARC can sell without recourse, on a revolving basis, up to $85.0 million of our receivables. ARC is obligated to pay fees that approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of our $320.0 million committed line of credit. As of June 30, 2007, we had sold $66.0 million in accounts receivable under this revolving agreement.

Credit Ratings

The following table summarizes our credit ratings as of August 7, 2007:

	Standard & Poor's	Moody's (1)	Fitch, Inc.
Avista Corporation			
Corporate/Issuer rating	BB+	Ba1	BB
Senior secured debt	BBB-	Baa3	BBB-
Senior unsecured debt	BB+	Ba1	BB+
Preferred stock	BB-	Ba3	BB
Avista Capital II (2)			
Preferred Trust Securities	BB-	Ba2	BB
AVA Capital Trust III (2)			
Preferred Trust Securities	BB-	Ba2	BB
Rating outlook	Positive (3)	Stable	Positive

(1) In June 2007, Moody's placed all of Avista Corporation's ratings under review for potential upgrade.
(2) Only assets are subordinated debentures of Avista Corporation.
(3) Changed to positive from stable in April 2007.

These security ratings are not recommendations to buy, sell or hold securities. The ratings are subject to change or withdrawal at any time by the respective credit rating agencies. Each credit rating should be evaluated independently of any other ratings.

Pension Plan

As of June 30, 2007, our pension plan had assets with a fair value that was less than the benefit obligation under the plan. We contributed $15 million to the pension plan in 2006. We are planning to contribute $15 million to the pension plan in 2007 ($7.5 million was contributed during the first half of 2007). Our total pension plan contributions were $77 million from 2002 through the first quarter of 2007.

The Pension Protection Act of 2006 (the Pension Act) was signed into law in August 2006. The Pension Act provides new funding rules for pension plans to improve the funded status of corporate defined benefit plans. The new funding rules could increase our minimum required cash contributions to the pension plan in the future. The legislation is effective in 2008; however, the law contains a transition period related to the funding rules. We do not expect the Pension Act to have a material effect on our financial condition, results of operations or cash flows.

Dividends

The Board of Directors considers the level of dividends on our common stock on a regular basis, taking into account numerous factors including, without limitation:

- our results of operations, cash flows and financial condition,
- the success of our business strategies, and
- general economic and competitive conditions.

Our net income available for dividends has generally been derived from our regulated utility operations (Avista Utilities) and Avista Energy.

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock contained in our Restated Articles of Incorporation, as amended, and to long-term debt contained in various indentures. Covenants under the 9.75 percent Senior Notes that mature in 2008 limit our ability to increase common stock cash dividends to no more than 5 percent over the previous quarter, unless certain conditions are met related to restricted payments. As of June 30, 2007, we are meeting the conditions that would allow us to increase the common stock cash dividend in excess of 5 percent over the previous quarter.

On May 10, 2007, the Board of Directors declared a quarterly dividend of $0.15 per common share payable on June 15, 2007 to shareholders of record on May 24, 2007. This was an increase of $0.005 per common share over the previous quarterly dividend declared in February 2007. This was the sixth common stock dividend increase authorized by the Board of Directors in the past four years.

As further discussed at “Note 13 of the Notes to the Consolidated Financial Statements,” the IPUC accepted a stipulation that we entered with the IPUC Staff that sets forth a variety of conditions if and when we implement a holding company structure. One of the conditions would require IPUC approval of any dividend to the holding company that would reduce utility common equity below 25 percent. Furthermore, we have entered into a similar agreement with the WUTC Staff. This agreement would require WUTC approval of any dividend to the holding company that would reduce utility common equity below 30 percent.

Avista Energy holds a significant portion of cash and cash equivalents reflected on our Consolidated Balance Sheets. Covenants in Avista Energy’s credit agreement, certain counterparty agreements and market liquidity conditions resulted in Avista Energy maintaining certain levels of cash and therefore have effectively limited the amount of cash dividends that were available for distribution to Avista Capital and ultimately to Avista Corp. With the completion of the sale of contracts and the liquidation of Avista Energy’s remaining net current assets, Avista Energy’s cash and restricted cash will be available for dividends to Avista Capital. We are expecting to generate approximately $170 million in cash proceeds from the transaction in the third quarter of 2007 (substantially all received by the end of July), including the liquidation of Avista Energy’s net current assets not sold to Coral Energy (primarily receivables, restricted cash and deposits with counterparties).

Avista Utilities Operations

We are expecting utility capital expenditures to be in the range of $180 to $190 million for 2007. We expect to have a utility capital budget of over $200 million in each of 2008, 2009 and 2010. Significant projects include the continued enhancement of our transmission and distribution systems and upgrades to our generation facilities.

Our utility held cash deposits from other parties in the amount of $50.1 million as of June 30, 2007, which is included in deposits from counterparties on the Consolidated Balance Sheet. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of collateral.

See "Notes 9 and 10 of Notes to Consolidated Financial Statements" for additional details related to our financing activities.

Energy Marketing and Resource Management (Avista Energy) Operations

On June 30, 2007, Avista Energy and Avista Energy Canada, as co-borrowers, terminated a committed credit agreement with a group of banks in the aggregate amount of $145.0 million that had an expiration date of July 12, 2007. This credit agreement was terminated in connection with the closing of the sale of substantially all of the contracts and ongoing operations of Avista Energy and Avista Energy Canada as described at Note 3. There were not any early termination penalties incurred by Avista Energy or Avista Energy Canada.

Avista Capital provided performance guarantees to other parties with whom Avista Energy may be doing business. At any point in time, Avista Capital was only liable for the outstanding portion of the performance guarantee, which was $25.7 million as of June 30, 2007. The face value of all performance guarantees issued by Avista Capital for energy trading contracts at Avista Energy was $360.9 million as of June 30, 2007. These guarantees were terminated with the closing of the sale of Avista Energy's contracts on June 30, 2007, but remained in effect through the July 2007 settlement of Avista Energy's payables to counterparties.

Avista Energy managed collateral requirements with counterparties by providing letters of credit, providing guarantees from Avista Capital, depositing cash with counterparties and offsetting transactions with counterparties. Cash deposited with counterparties totaled $31.1 million as of June 30, 2007, a decrease from $79.5 million as of December 31, 2006. These cash deposits were returned to Avista Energy in July 2007. Avista Energy did not hold any cash deposits from other parties as of June 30, 2007.

As of June 30, 2007, Avista Energy had $104.9 million in cash, as well as $3.6 million of restricted cash. The increase in cash from a balance of $29.6 million at December 31, 2006 was primarily due to the liquidation of restricted cash and the return from counterparties of cash deposited as collateral for energy contracts.

Contractual Obligations

During the six months ended June 30, 2007, our future contractual obligations have not changed materially from the amounts disclosed in the 2006 Form 10-K with the following exceptions:

The amount outstanding under our revolving accounts receivable sales financing facility decreased from $85.0 million as of December 31, 2006 to $66.0 million as of June 30, 2007. In March 2007, the termination date of this facility was extended from March 20, 2007 to March 17, 2008.

The amount outstanding under our $320.0 million committed line of credit increased to $16.0 million as of June 30, 2007 from $4.0 million as of December 31, 2006.

Avista Energy's contractual commitments to purchase energy commodities as well as commitments related to transmission, transportation and other energy-related contracts in future periods were as follows as of June 30, 2007 (dollars in millions):

For the 12-month period ended June 30,	2008	2009	2010	2011	2012	Thereafter
Energy purchase contracts	$ 21,700	$ 21,700	$ 23,901	$ 26,102	$ 26,102	$ 325,852

These contractual commitments of Avista Energy are primarily related to the power purchase agreement for the Lancaster Plant. These obligations and benefits of this agreement have been sold to Coral Energy through the end of 2009. Beginning in 2010 through 2026, the obligations and benefits of the power purchase agreement for the Lancaster Plant will be contracted to Avista Energy. We expect that these obligations and benefits will be transferred to our regulated utility, subject to future approval by the WUTC and IPUC.

Business Risk

Primarily through our utility operations, we are exposed to the following risks including, but not limited to:

- market prices and supply of wholesale energy, which we purchase and sell, including power, fuel and natural gas,
- regulatory allowance of the recovery of power and natural gas costs, operating costs and capital investments,
- streamflow and weather conditions,

- the effects of changes in legislative and governmental regulations, including restrictions on emissions from generating plants and requirements for the acquisition of new resources,
- changes in regulatory requirements,
- availability of generation facilities,
- competition,
- technology, and
- availability of funding.

Also, like other utilities, our facilities and operations are exposed to natural disasters and terrorism risks or other malicious acts. See further reference to risks and uncertainties under "Forward-Looking Statements."

Our business risk has not materially changed during the six months ended June 30, 2007. However, our risk profile related to Avista Energy's operations has changed with the closing of the sale of contracts and ongoing operations to Coral Energy. Please refer to the 2006 Form 10-K for further description and analysis of business risk including, but not limited to, commodity price, credit, other operating, interest rate and foreign currency risks.

Risk Management

Risk Policies and Oversight

We use a variety of techniques to manage risks for energy resources and wholesale energy market activities. We have risk management policies and procedures to manage these risks, both qualitative and quantitative. Risk management policies and procedures for Avista Energy have been suspended following the closing of the sale of substantially all of Avista Energy's contracts and ongoing operations on June 30, 2007. Please refer to the 2006 Form 10-K for discussion of risk management policies and procedures.

Environmental Issues and Other Contingencies

We are subject to environmental regulation by federal, state and local authorities. The generation, transmission, distribution, service and storage facilities in which we have an ownership interest were designed to comply with all applicable environmental laws.

We monitor legislative developments at both the state and national level with respect to environmental issues, particularly those related to the potential for further restrictions on the operation of our generating plants.

Current environmental laws and regulations have, and future modifications may have, the effect of:

- increasing the lead time for the construction of new generating plants,
- requiring modification of our existing generating plants,
- increasing the risk of delay on construction projects,
- reducing the amount of energy available from our generating plants, and
- restricting the types of generating plants that can be built.

As such, compliance with such environmental laws and regulations could result in increases to capital expenditures and operating expenses. However, we intend to seek recovery of incurred costs through the rate making process.

Long-term global climate changes, particularly with respect to the Pacific Northwest, could have a significant effect on our business. Changing temperatures and precipitation, including snowpack conditions, affect the availability and timing of hydroelectric generation capacity. Changing temperatures could also increase or decrease customer demand. Our operations could also be affected by any legislative or regulatory developments in response to global climate changes, including restrictions on the operation of our power generation resources.

We continue to monitor and evaluate the possible adoption of national, regional, or state greenhouse gas requirements. In particular, a greenhouse gas bill has been passed by the legislature in the state of Washington and bills have been introduced in the U. S. Senate and House of Representatives. There will most likely be continuing activity in the near future.

The greenhouse gas bill passed by the legislature in the state of Washington would place significant restrictions on greenhouse gas emissions from any new generation plants built in the state of Washington. Furthermore, utilities would be prevented from entering into contracts to purchase energy produced by plants in other states that do not meet the same restrictions. Currently, the only type of thermal generating plants that meet these restrictions are combined-cycle natural gas-fired generation turbines. This greenhouse gas bill sets goals to reduce emissions in the state of Washington to 1990 levels by 2020; to 25 percent below 1990 levels by 2035; and to 50 percent below 1990 levels by 2050.

Greenhouse gas requirements could result in significant costs for us to comply with restrictions on carbon dioxide or other greenhouse gas emissions. Such requirements could also preclude us from developing certain types of generating plants, including coal-fired plants.

Initiative Measure 937 (I-937) was passed into law through the General Election in Washington in November 2006. I-937 requires certain investor-owned, cooperative, and government-owned electric utilities (including Avista Corp.) to acquire new renewable energy resources and/or renewable energy credits in incremental amounts until those resources or credits equal 15 percent of the utility's total retail load in 2020. I-937 also requires these utilities to meet biennial energy conservation targets beginning in 2012. Failure to comply with renewable energy and conservation standards will result in penalties of at least $50 per MWh being assessed against a utility for each MWh it is deficient in meeting a standard. A utility would be deemed to comply with the renewable energy standard if it invests at least 4 percent of its total annual retail revenue requirement on the incremental costs of renewable resources and/or renewable credits. Our most recent draft Electric Integrated Resource Plan (IRP), which we plan to file with the WUTC and IPUC before the end of the third quarter 2007, includes the acquisition of additional renewable resources such that, if the draft IRP is implemented, we would be compliant with the requirement by the various milestone dates. In the draft IRP, we do not anticipate adding a major generation project until 2014. The amount of renewable resources in our future IRPs could change if the cost effectiveness of those resources changes.

For other environmental issues and other contingencies see "Note 12 of the Notes to Consolidated Financial Statements."

Item 3. Quantitative and Qualitative Disclosures About Market Risk

See "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations: – Business Risk and – Risk Management," "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations – Energy Marketing and Resource Management – Energy trading activities and positions," and "Note 6 of the Notes to Consolidated Financial Statements."

Item 4. Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended) to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company's management, including its principal executive and principal financial officers as appropriate to allow timely decisions regarding required disclosure. Under the supervision and with the participation of the Company's management, including the Company's principal executive officer and principal financial officer, the Company has evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon the Company's evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures are effective at a reasonable assurance level as of June 30, 2007.

There have been no changes in the Company's internal control over financial reporting that occurred during the second quarter of 2007 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

See "Note 12 of the Notes to Consolidated Financial Statements" in "Part I. Financial Information Item 1. Consolidated Financial Statements."

Item 1A. Risk Factors

Please refer to the 2006 Form 10-K for disclosure of risk factors that could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results or outcomes to differ materially from those discussed in our reports filed with the Securities and Exchange Commission (including this Quarterly Report on Form 10-Q), and elsewhere. These risk factors have not materially changed from the disclosures provided in the 2006 Form 10-K.

Our risk factors related to Avista Energy's operations have changed with the closing of the sale of contracts and ongoing operations to Coral Energy, as many of the risk factors specifically related to Avista Energy have been eliminated.

In addition to these risk factors, please also see "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations – Forward-Looking Statements" for additional factors which could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

Item 4. Submission of Matters to a Vote of Security Holders

The 2007 Annual Meeting of Shareholders of Avista Corp. was held on May 10, 2007. The election of four directors with terms expiring in 2010 and one director with a term expiring in 2009, to amend the Restated Articles of Incorporation and Bylaws to allow for annual election of directors and the ratification of the appointment of the firm of Deloitte & Touche LLP as the independent registered public accounting firm of the Company for 2007 were the only matters voted upon at the meeting. The proposal to amend the Articles of Incorporation and Bylaws required an affirmative vote of 80 percent of the outstanding shares of the Company, which was not received and the proposal was not approved. There were 52,724,612 shares of common stock issued and outstanding as of March 9, 2007, the proxy record date, with 48,001,005 shares represented at said meeting. The results of the voting are shown below:

Issue	For	Against or Withheld	Exceptions or Abstain
Election of Directors:			
Eric J. Anderson (term expires 2010)	47,028,071	972,934	
Kristianne Blake (term expires 2010)	47,375,964	625,041	
Jack W. Gustavel (term expires 2010)	47,379,869	621,136	
Scott L. Morris (term expires 2009)	47,394,078	606,927	
Michael L. Noel (term expires 2010)	47,061,005	940,000	
Amend the Restated Articles of Incorporation and Bylaws to allow for annual election of directors	36,839,789	1,170,140	9,991,076
Ratification of appointment of Deloitte & Touche, LLP	47,495,472	159,570	345,963

The terms of directors Roy Lewis Eiguren, Gary G. Ely, John F. Kelly, Lura J. Powell, Ph.D., Heidi B. Stanley and R. John Taylor continued. On February 9, 2007, Gary G. Ely, Chairman of the Board and Chief Executive Officer of Avista Corp., announced to the Company's board of directors, that he will retire from the Company and the board effective December 31, 2007. The Company's board of directors elected Scott L. Morris to the positions of Chairman of the Board and Chief Executive Officer of Avista Corp. effective January 1, 2008.

Item 6. Exhibits

10.1	Indemnification Agreement entered into as of June 30, 2007 by Coral Energy Holding, L.P. and certain of its affiliates and Avista Energy, Inc. and certain of its affiliates.*
10.2	Guaranty Agreement effective as of June 30, 2007 entered into by Avista Capital, Inc. in favor of Coral Energy Holding, L.P. and certain of its affiliates.*
10.3	Security Agreement dated as of June 30, 2007 given by Avista Capital, Inc. in favor of Coral Energy Holding, L.P. and certain of its affiliates.*
12	Computation of ratio of earnings to fixed charges and preferred dividend requirements*
15	Letter Re: Unaudited Interim Financial Information*
31.1	Certification of Chief Executive Officer*
31.2	Certification of Chief Financial Officer*
32	Certification of Corporate Officers (Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)**

* Filed herewith.
** Furnished herewith.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

AVISTA CORPORATION
(Registrant)

Date: August 8, 2007

/s/ Malyn K. Malquist
Malyn K. Malquist
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

Exhibit 10.1

EXECUTION TEXT

INDEMNIFICATION AGREEMENT

THIS INDEMNIFICATION AGREEMENT (this "**Agreement**") is made and entered into as of June 30, 2007. The parties to this Agreement (the " **Parties** ") are Coral Energy Holding, L.P., a Delaware limited partnership (" **Coral Holding** "), Coral Energy Resources, L.P., a Delaware limited partnership (" **Coral Resources** "), Coral Power, L.L.C., a Delaware limited liability company (" **Coral Power** "), and Coral Energy Canada Inc., a corporation of the province of Alberta, Canada (" **Coral Canada** " and, together with Coral Holding, Coral Resources and Coral Power, each a " **Coral Entity** " and together the " **Coral Entities** ," all of which are Affiliates of one another); and Avista Energy, Inc., a Washington corporation (" **Avista Energy** "), Avista Energy Canada, Ltd., an amalgamated corporation of the province of Alberta, Canada (" **Avista Canada** "), and Avista Turbine Power, Inc., a Washington Corporation (" **Avista Turbine** " and, together with Avista Energy and Avista Canada, each an " **Avista Entity** " and together the " **Avista Entities** ," all of which are Affiliates of one another). Capitalized terms used and not otherwise defined in this Agreement shall have the meanings given in the Purchase Agreement (defined below).

RECITALS

A. Avista Energy and Avista Canada, as Sellers, entered into a Purchase and Sale Agreement dated as of April 16, 2007, with the Coral Entities, as Purchasers (the " **Purchase Agreement** "), by which the Coral Entities will purchase substantially all of the operating assets of Avista Energy and Avista Canada.

B. Concurrently with the Parties' entry into this Agreement and as of the Effective Time:

1. Avista Energy, Avista Canada and the Coral Entities may enter into an Agency Agreement (the "**Agency Agreement**") pursuant to which Avista Energy and Avista Canada would appoint certain of the Coral Entities as their agents with respect to certain of the Assigned Contracts;

2. Avista Energy, Avista Canada and the Coral Entities are entering into a Post-Closing Transition Services Agreement (the "**Transition Services Agreement** ") pursuant to which Avista Energy and Avista Canada have agreed to provide certain services to the Coral Entities for a limited period of time;

3. Avista Turbine and Coral Power are entering into an Energy Conversion Agreement (the "**Lancaster Agreement**") pursuant to which Coral Power is agreeing to purchase from Avista Turbine the capacity and energy generated from that certain power generation facility located in Rathdrum, Idaho; and

4. Avista Energy and Coral Resources are entering into that certain Agreement to Temporarily Assign Rights to Use Jackson Prairie Expansion Capacity (the " **JP Agreement** ") pursuant to which Coral Resources is obtaining from Avista Energy the right for a limited time to utilize the natural gas storage capacity held by Avista Energy located in Lewis County, Washington.

C. As part of the Purchase Agreement, the Agency Agreement (if and when entered into), the Transition Services Agreement, the Lancaster Agreement and the JP Agreement (collectively, with the documents and agreements entered into pursuant to such agreements, the " **Transaction Agreements** "), the Coral Entities and the Avista Entities are entering into this Agreement setting forth the terms and conditions under which the Parties are agreeing to provide indemnification for certain events that may arise out of or relate to the Transaction Agreements.

IN CONSIDERATION of the mutual promises, representations, warranties and covenants set forth in this Agreement, the Parties, each intending to be legally bound, agree as follows:

1. Definitions. As used in this Agreement:

(a) "Adverse Consequence" means any and all damages, assessments, charges, penalties, fines, costs, payments, Liabilities, debts, obligations, Taxes, liens, losses, expenses, fees or newly-imposed business restrictions, including court costs and reasonable attorneys' fees and expenses, arising out of or relating to one or more Claims or Orders.

(b) "Claim" means any demand, claim, action, investigation, legal proceeding (whether at law or in equity) or arbitration of any kind whatsoever, whether fixed or contingent.

(c) "Liability" means any liability (whether known or unknown, asserted or unasserted, absolute or contingent, accrued or unaccrued, liquidated or unliquidated, criminal or civil, or due or to become due), including any liability for Taxes.

(d) "Order" means any order, ruling, writ, judgment, injunction, decree, stipulation, determination or award entered by or with any Governmental Authority.

(e) "Third-Party" means any Person (including without limitation Governmental Authorities) other than the Coral Entities and their Affiliates or the Avista Entities and their Affiliates.

2. Indemnification Provisions for Benefit of the Coral Entities. Avista Energy, Avista Canada and, with respect to the Lancaster Agreement only, Avista Turbine, and each of them, jointly and severally, shall indemnify, defend and hold harmless the Coral Entities and each of their Affiliates, successors, officers, directors, employees and agents (each a " **Coral Indemnified Party** ") from and against the entirety of any Adverse Consequences any of them may suffer resulting from, arising out of, relating to, in the nature of, or caused by:

2.1 Breach of Representations and Warranties. Breach by Avista Energy or Avista Canada of one or more of its representations and warranties made in the Purchase Agreement, including, without limitation, any representation or warranty made in:

(a) Sections 3.1, 3.2 or 3.7 of the Purchase Agreement (the "**Title and Authority Representations**");

(b) Sections 3.14 or 3.15 of the Purchase Agreement (the "**Tax Representations**"); or

(c) Section 3.17 of the Purchase Agreement (the "**Environmental Representations**").

2.2 Coral Entity Claims. Claims of any Coral Entity, or Claims against any Coral Entity by Third Parties, resulting from, arising out of, relating to, in the nature of or caused by (a) any breach by (i) an Avista Entity of or default by it under any of its covenants contained in the Purchase Agreement, Agency Agreement or Transition Services Agreement, or (ii) any member of the Avista Group of or default by it under Section 10 of the Purchase Agreement, in each case as such covenants pertain to obligations arising or actions to be taken following the Effective Time, (b) with respect to Third Party Claims only, the ownership or operation of the Acquired Assets on or prior to the Effective Time, or (c) the ownership or operation by of the Excluded Assets or the Retained Liabilities prior to, on or after the Effective Time.

2.3 Claims under Lancaster and JP Agreements. Claims of any Coral Entity resulting from, arising out of, relating to, in the nature of or caused by any breach by an Avista Entity of or default by it under any of its representations, warranties and covenants contained in the Lancaster Agreement or the JP Agreement.

3. Indemnification Provisions for Benefit of the Avista Entities. The Coral Entities and each of them, jointly and severally, shall indemnify, defend and hold harmless the Avista Entities, their Affiliates, successors, officers, directors, employees and agents (each an " **Avista Indemnified Party** ") from and against the entirety of any Adverse Consequences any of them may suffer resulting from, arising out of, relating to, in the nature of, or caused by:

3.1 Breach of Representations and Warranties. Breach by any of the Coral Entities of one or more of its representations and warranties made in the Purchase Agreement. The preceding obligations shall include, without limitation, breach of any representation or warranty made in Section 4.1 or 4.2 (the " **Coral Authority Representations** ") or Section 4.7 (the " **Coral Tax Representation** ") of the Purchase Agreement

3.2 Avista Entity Claims. Claims of any Avista Entity, or Claims against any Avista Entity by Third Parties, resulting from, arising out of, relating to, in the nature of or caused by any breach by a Coral Entity of or default by it under any of its covenants contained in the Purchase Agreement, the Agency Agreement or Transition Services Agreement as such covenants pertain to obligations arising or actions to be taken following the Effective Time, or the ownership or operation of the Acquired Assets and assumption of the Assumed Liabilities by the Coral Entities or their Affiliates after the Effective Time.

3.3 Claims under Lancaster and JP Agreements. Claims of any Avista Entity resulting from, arising out of, relating to, in the nature of or caused by any breach by a Coral Entity of or default by it under any of its representations, warranties and covenants contained in the Lancaster Agreement or the JP Agreement.

4. Claims for Indemnification; Matters Involving Third Parties.

4.1 Notice. If any Coral Indemnified Party or Avista Indemnified Party (the "**Indemnified Party**") becomes aware of any matter that may give rise to a Claim for indemnification under this Agreement (an " **Indemnification Claim** ") against any of the Avista Entities or Coral Entities, as the case may be (the " **Indemnifying Party** "), then the Indemnified Party shall give prompt written notice to the Indemnifying Party of each such Claim, stating the nature of such Claim in reasonable detail and indicating the estimated amount, if practicable, of the loss related thereto. Delay on the part of the Indemnified Party in providing notice shall not relieve the Indemnifying Party from its obligations hereunder unless (and then only to the extent that) the Indemnifying Party is prejudiced or damaged by such delay.

4.2 Acceptance or Rejection. If Indemnifying Party does not accept or affirmatively rejects such Indemnification Claim within thirty (30) days of the date the Indemnified Party provides written notice of the Indemnification Claim to the Indemnifying Party, the Indemnified Party shall be free to seek enforcement of its rights to indemnification under this Agreement. If the Indemnifying Party agrees that it has an indemnification obligation but objects that it is obligated to pay only a lesser amount, the Indemnified Party shall nevertheless be entitled to recover promptly from the Indemnifying Party the lesser amount, without prejudice to the Indemnified Party's Claim for the difference.

4.3 Third Party Claims. If the Indemnification Claim results from a Third-Party Claim or proceeding, the Indemnifying Party will have the right to defend the Indemnified Party against the Third-Party Claim or proceeding with counsel of their choice reasonably satisfactory to the Indemnified Party so long as (i) the Indemnifying Party notifies the Indemnified Party in writing within thirty (30) days after the Indemnified Party has given notice of the Indemnification Claim that the Indemnifying Party will indemnify the Indemnified Party from and against the entirety of any Adverse Consequences, to the fullest extent required under this Agreement, the Indemnified Party may suffer resulting from, arising out of, relating to, in the nature of, or caused by the Indemnification Claim, (ii) the Indemnifying Party provides the Indemnified Party with evidence reasonably acceptable to the Indemnified Party that the Indemnifying Party will have the financial resources to defend against the Indemnification Claim and fulfill its indemnification obligations under this Agreement, and (iii) the Indemnifying Party conducts the defense of the Indemnification Claim actively and diligently.

4.4 Indemnified Party's Rights. So long as the Indemnifying Party is conducting the defense of the Indemnification Claim in accordance with this Agreement, (i) the Indemnified Party may retain separate co-counsel, at its sole cost and expense, and participate in the defense of the Indemnification Claim and (ii) the Indemnified Party will not consent to the entry of any judgment or enter into any settlement with respect to the Indemnification Claim without the prior written consent of the Indemnifying Party which consent will not be unreasonably withheld or delayed.

4.5 Failure to Defend. In the event the Indemnifying Party fails to conduct the defense of an Indemnification Claim that results from a Third-Party Claim or proceeding in accordance with this Agreement, (i) the Indemnified Party may defend against, and consent to the entry of any judgment or enter into any settlement with respect to, the Third-Party Claim or proceeding giving rise to the Indemnification Claim in any manner it may deem appropriate (and the Indemnified Party need not consult with, or obtain any consent from, any Indemnifying Party in connection with the same), (ii) the Indemnifying Party will have the obligation to reimburse the Indemnified Party promptly and periodically for the costs of defending against the Indemnification Claim (including reasonable attorneys' fees and expenses) and (iii) the Indemnifying Party will remain responsible for any Adverse Consequences the Indemnified Party may suffer resulting from, arising out of, relating to, in the nature of, or caused by the Indemnification Claim to the fullest extent provided in this Agreement.

5. Determination of Adverse Consequences. The Parties shall take into account the time value/cost of money (using the Applicable Rate as the discount rate) and also any net Tax benefits/costs in determining Adverse Consequences for purposes of this Agreement.

6. Claims that Related to Periods Both Before and After the Effective Time. The Parties have attempted to allocate their responsibility and indemnification obligations in respect of the Effective Time. To the extent that any Claims otherwise covered by this Agreement relate to both the period on and prior to the Effective Time and the period after the Effective Time, the Indemnification Claim resulting therefrom and the indemnification obligations in respect thereof shall be allocated to the Avista Entities in proportion to the period prior to the Effective Time and to the Coral Entities in proportion to the period after the Effective Time. If the proportion of indemnification obligations cannot be determined between the Parties in good faith, as set forth in this Section 6, such determination shall be submitted to the trier of such Claim which determination shall be final and binding as to the Parties.

7. Limitations on Liability.

7.1 Liability Threshold. Except as provided in the following sentence, and subject to Section 7.3 and 7.4, no Party shall be liable under this Agreement until the aggregate for all Indemnification Claims made by all Coral Indemnified Parties or Avista Indemnified Parties, as the case may be, under this Agreement is in excess of $150,000 and then only for such excess over the $150,000 aggregate threshold. Notwithstanding the foregoing liability threshold, the Avista Entities' indemnification obligations for the Title and Authority Representations, Tax Representations and as set forth in Sections 2.2 and 2.3, above, and the Coral Entities' indemnification obligations for the Coral Authority Representations and Coral Tax Representation and as set forth in Sections 3.2 and 3.3, above, shall be not be subject to such liability threshold limitation, and may be exercised in respect of the "first dollar" of any Indemnification Claim.

7.2 Maximum Liability. Except as provided in the following sentence and Section 7.4, the maximum aggregate liability of the Indemnifying Parties to the Indemnified Parties under this Agreement shall in no event exceed an amount equal to $30,000,000. Notwithstanding the foregoing:

(a) the Avista Entities' indemnification obligations for the Title and Authority Representations and the Coral Entities' indemnification obligations for the Coral Authority Representations shall not exceed the Purchase Price; and

(b) the Avista Entities' indemnification obligations set forth in Section 2.2, above and the Coral Entities' indemnification obligations set forth in Section 3.2, above, shall be unlimited in dollar amount.

7.3 Survival of Indemnification Rights. An Indemnification Claim under this Agreement must be made, if at all, prior to the expiration of the following time periods:

(a) In the case of Indemnification Claims under Section 2.2 and Section 3.2 for which a performance period is specified, the duration of such performance period;

(b) In the case of Indemnification Claims under Section 2.2 and 3.2 other than as set forth in Section 7.3(a) above, there shall be no expiration period under this Agreement;

(c) In the case of Indemnification Claims under Section 2.1 or 3.1, other than as set forth in Section 7.3(d) below, such Indemnification Claim must be made no later than 18 months after the Effective Time;

(d) In the case of Indemnification Claims with respect to any of the Title and Authority, Tax, Environmental and Coral Authority Representations and Coral Tax Representations, such Indemnification Claim must be made no later than the third (3^{rd}) anniversary of the Effective Time; and

(e) In the case of Indemnification Claims under Section 2.3 and Section 3.3, such Indemnification Claim must be made no later than thirty (30) days following the term of such agreement.

Indemnification Claims shall be barred if not made prior to the above expiration dates, and all obligations of indemnification with respect to such Indemnification Claims shall terminate and be of no further force or effect if such Indemnification Claims are not made prior to such dates.

7.4 Certain Breaches Not Subject to Limitations. Claims for indemnification with respect to (i) fraud or (ii) intentional misrepresentation shall not be subject to any of the limitations set forth in Section 7.1, Section 7.2, Section 7.3, Section 8 or Section 9.

8. Exclusive Remedy. The rights of the Avista Entities and the Coral Entities to assert Indemnification Claims and to receive indemnification payments pursuant to this Agreement shall be their sole and exclusive right and remedy with respect to any breach by any other party of any representation, warranty or covenant contained in the Transaction Agreements, except for the rights provided to the Parties to seek injunctions to prevent breaches of the Transaction Agreements or to enforce specifically the Transaction Agreements, as provided therein, and in all cases subject to the limitations on liability established in this Agreement.

9. Consequential Damages Limitation. Except as provided in the following sentence, in no event shall any Party have any obligation or liability arising under or relating to the Transaction Agreements (or any other agreement, document or certificate delivered in connection with the transactions contemplated by the Transaction Agreements) or this Agreement for any consequential, punitive, special or indirect loss or damage, including lost profits or lost opportunities, and each Party hereby expressly releases the other Parties from the same. As between the Parties to this Agreement, Claims for indemnification with respect to Third-Party Claims under this Agreement shall not be subject to the limitations set forth in the previous sentence to the extent of such Claims by Third-Parties, but the Parties acknowledge and agree that nothing contained in this Agreement is intended to, nor shall be construed to,

waive, modify, amend or release any independent waiver of such consequential damages as may exist with respect to such Third-Party Claims outside of this Agreement or create a right for any person to recover consequential damages.

10. Miscellaneous.

10.1 Reliance. Each of the Coral Entities and the Avista Entities expressly confirms and agrees that it has entered into this Agreement and assumes the obligations imposed on it hereby in order to induce the other Parties to enter into the Transaction Agreements, and each of the Coral Entities and each of the Avista Entities acknowledges that the other Parties are relying upon this Agreement in entering into the Transaction Agreements.

10.2 Entire Agreement. This Agreement, the Transaction Agreements (including the documents referred to therein) and the Guaranty, the Security Agreement and the Escrow Agreement constitutes the entire agreement between the Parties hereto with respect to the subject matter hereof and supersedes any prior understandings, agreements or representations by or among the Parties, written or oral, to the extent they related in any way to the subject matter of this Agreement and the Transaction Agreements.

10.3 Succession and Assignment. This Agreement shall be binding upon and inure to the benefit of the Parties named in this Agreement and their respective successors and permitted assigns. Except as provided in the next sentence, no party may assign either this Agreement or any of its rights, interests or obligations under this Agreement without the prior written approval of the other Parties. The Coral Entities and the Avista Entities shall be entitled to assign this Agreement and any and all of their rights and interests under it to any Affiliate without the prior written approval of the other Parties, but such an assignment shall not relieve, discharge or otherwise affect the duties and obligations of the assigning Party under this Agreement, all of which shall remain in full force and effect.

10.4 Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original but all of which together will constitute one and the same instrument.

10.5 Headings. The Section headings contained in this Agreement are inserted for convenience only and shall not affect in any way the meaning or interpretation of this Agreement.

10.6 Notices. All notices, Indemnification Claims and other communications under this Agreement will be in writing. Any notice, Indemnification Claim or other communication under this Agreement shall be deemed duly given if it is sent to the intended recipient as set forth below:

If to the Avista Entities to:

Avista Energy, Inc.
c/o Avista Corporation
1411 East Mission Avenue
Spokane, Washington 99202
Facsimile: (509) 495-4361
Attn.: General Counsel

With copies to:

Avista Capital, Inc.
1411 East Mission Avenue
Spokane, Washington 99202
Facsimile: (509) 495-4361
Attn.: General Counsel

and to:

Heller Ehrman LLP
701 Fifth Avenue, Suite 6100
Seattle, Washington 98104
Facsimile: (206) 447-0849
Attn.: Bruce M. Pym

If to the Coral Entities to:

Coral Energy Holding, L.P.
Coral Energy Resources, L.P.
Coral Power, L.L.C.
909 Fannin, Plaza, Level 1
Houston, Texas 77010
Facsimile: (713) 767-5699
Attn.: Senior Vice President

Coral Energy Canada Inc.
3500, 450 - 1st Street S.W.
Calgary, Alberta
T2P 5H1
Facsimile: 403-716-3501
Attn: Senior Vice President

With copies to:

Coral Energy Holding, L.P.
909 Fannin Street, Level 1
Houston, Texas 77010
Facsimile: (713) 767-5699
Attn.: General Counsel

Any party may send any notice, Indemnification Claim or other communication under this Agreement to the intended recipient at the address set forth above using personal delivery, expedited or overnight courier, messenger service, facsimile or ordinary mail, but no such notice, Indemnification Claim or other communication shall be deemed to have been duly given unless and until it actually is received by or at the address or number of the intended recipient as specified in this Section 10.6. Any party may change the address to which notices, Indemnification Claims and other communications under this Agreement are to be delivered by giving the other Parties notice in the manner set forth in this Agreement.

10.7 Governing Law. This Agreement shall be governed by and construed in accordance with the domestic laws of the State of New York without giving effect to any choice or conflict of law provision or rule (whether under 5-1401 and 5-1402 of the New York General Obligations Law or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than the State of New York.

10.8 Amendments and Waivers. No amendment of any provision of this Agreement shall be valid unless the same shall be in writing and signed by the Avista Entities and the Coral Entities. No waiver by any party of any default under this Agreement, whether intentional or not, shall be deemed to extend to any prior or subsequent default under this Agreement or affect in any way any rights arising by virtue of any prior or subsequent such occurrence.

10.9 Severability. Any term or provision of this Agreement that is invalid or unenforceable in any situation in any jurisdiction shall not affect the validity or enforceability of the remaining terms and provisions of this Agreement or the validity or enforceability of the offending term or provision in any other situation or in any other jurisdiction. Without limiting the generality of the foregoing, this Agreement is intended to confer upon the Parties indemnification rights to the fullest extent permitted by applicable laws. In the event any provision hereof conflicts with any applicable law, such provision shall be deemed modified, consistent with the aforementioned intent, to the extent necessary to resolve such conflict.

10.10 Construction. The Parties have participated jointly in the negotiation and drafting of this Agreement. In the event an ambiguity or question of intent or interpretation arises, this Agreement shall be construed as if drafted jointly by the Parties and no presumption or burden of proof shall arise favoring or disfavoring any party by virtue of the authorship of any of the provisions of this Agreement. The words “includes” and “including” shall not be words of limitation. The Parties intend that each covenant contained in this Agreement shall have independent significance. If any party has breached any covenant contained in this Agreement in any respect, the fact that there exists another covenant relating to the same subject matter (regardless of the relative levels of specificity) that the party has not breached shall not detract from or mitigate the fact that the party is in breach of the first covenant.

10.11 Interpretation and Construction. In interpreting and construing this Agreement, the following principles shall be followed:

(a) examples shall not be construed to limit, expressly or by implication, the matter they illustrate;

(b) the terms “herein,” “hereof,” “hereby,” and “hereunder,” or other similar terms, refer to this Agreement as a whole and not only to the particular article, section or other subdivision in which any such terms may be employed;

(c) references to sections and other subdivisions refer to the sections and other subdivisions of this Agreement;

(d) no consideration shall be given to the captions of the sections, subsections, or clauses, which are inserted for convenience in locating the provisions of this Agreement and not as an aid in its construction;

(e) the word “includes” and its syntactical variants mean “includes, but is not limited to” and corresponding syntactical variant expressions and the term “and/or” shall mean “or”;

(f) currency amounts referenced herein, unless otherwise specified, are in U.S. Dollars;

(g) whenever this Agreement refers to a number of days, such number shall refer to calendar days unless Business Days are specified;

(h) the plural shall be deemed to include the singular, and vice versa; and

(i) each exhibit, attachment, and schedule to this Agreement is a part of this Agreement, but if there is any conflict or inconsistency between the main body of this Agreement and any exhibit, attachment, or schedule, the provisions of the main body of this Agreement shall prevail.

EXECUTED effective as of the date first above written.

CORAL ENTITIES

CORAL ENERGY HOLDING, L.P.

By: /s/ Beth A. Bowman
Name: Beth A. Bowman
Title: Senior Vice President

CORAL ENERGY RESOURCES, L.P.

By: /s/ Beth A. Bowman
Name: Beth A. Bowman
Title: Senior Vice President

CORAL POWER, L.L.C.

By: /s/ Beth A. Bowman
Name: Beth A. Bowman
Title: Senior Vice President

CORAL ENERGY CANADA INC.

By: /s/ Arnold MacBurnie
Name: Arnold MacBurnie
Title: Senior Vice President

AVISTA ENTITIES

AVISTA ENERGY, INC.

By: /s/ Dennis P. Vermillion
Name: Dennis P. Vermillion
Title: President & Chief Operating Officer

AVISTA ENERGY CANADA, LTD.

By: /s/ Malyn K. Malquist
Name: Malyn K. Malquist
Title: Senior Vice President, Chief Financial Officer & Treasurer

AVISTA TURBINE POWER, INC.

By: /s/ Dennis P. Vermillion
Name: Dennis P. Vermillion
Title: President

Exhibit 10.2

GUARANTY

This Guaranty Agreement (this "Guaranty") dated effective as of June 30, 2007, is entered into by Avista Capital, Inc. ("Guarantor"), a Washington corporation, in favor of Coral Energy Holding, L.P., a Delaware limited partnership, Coral Energy Resources, L.P., a Delaware limited partnership, Coral Power, L.L.C., a Delaware limited liability company and Coral Energy Canada Inc., an Alberta corporation (each being a "Coral Entity" and collectively, the "Coral Entities").

Recitals:

A. Guarantor desires that the Coral Entities enter into the contracts and agreements listed on Attachment A hereto with affiliates of Guarantor including Avista Energy, Inc., Avista Energy Canada, Ltd. and Avista Turbine Power, Inc. (each being a "Guaranteed Party" and collectively, the "Guaranteed Parties"), as such contracts and agreements listed on Attachment A may be amended, supplemented, renewed, or extended, collectively, from time to time, the "Contracts"; and

B. The Guaranteed Parties are subsidiaries or affiliates of Guarantor and Guarantor will directly or indirectly benefit from the Contracts to be entered into between one or more of the Coral Entities and one or more of the Guaranteed Parties; and

C. The Guaranteed Parties and the Coral Entities are parties to an Indemnification Agreement of even date herewith with respect to certain obligations between such parties in respect of the Contracts (the "Indemnification Agreement").

NOW, THEREFORE, in consideration of the Coral Entities entering into the Contracts with Guaranteed Parties, Guarantor hereby covenants and agrees as follows:

1.**Guaranty**. Subject to the terms and conditions hereof, Guarantor hereby irrevocably and unconditionally guarantees the timely performance and payment when due of the obligations of Guaranteed Parties (the "Obligations") to the Coral Entities, as applicable, under the Indemnification Agreement with respect to the Contracts. To the extent that a Guaranteed Party shall fail to perform or pay any Obligation, Guarantor shall promptly cause the performance or pay to the applicable Coral Entity the amount due in accordance with the terms, conditions and limitations contained in the Indemnification Agreement. This Guaranty shall constitute a guarantee of payment and not of collection. Guarantor shall also be liable for the reasonable attorneys' fees and expenses of such Coral Entity's external counsel incurred in any successful effort to collect or enforce any of the obligations under this Guaranty.

2.**Limitations**. Guarantor's performance hereunder shall be limited to monetary payments arising out of the Obligations (even if such payments are deemed to be damages) and in no event shall Guarantor be subject hereunder to consequential, exemplary, equitable, loss of profits, punitive, or any other damages, except to the extent specifically provided in the Indemnification Agreement to be due from a Guaranteed Party. Guarantor waives any and all defenses, rights and benefits Guarantor might assert to avoid or limit liability on Guarantor's obligations arising from the bankruptcy, insolvency, dissolution, or liquidation of Guaranteed Party. The aggregate amount of Guarantor's liability under or in respect of this Guaranty shall in no event exceed Thirty Million Dollars (U.S.$30,000,000), in the aggregate, plus attorney's fees and other expenses specified under Section 1 hereto and shall be calculated by including any amounts paid by any Guaranteed Party under the Indemnification Agreement, or collected on any collateral securing Guarantor's obligations under this Guaranty, against such Thirty Million Dollar cap on Guarantor's liability.

3.**Termination**. This Guaranty shall remain in full force and effect until April 30, 2011. No termination shall affect, release or discharge Guarantor's liability with respect to any Obligations existing or arising prior to the effective date of termination.

4.**Nature of Guaranty**. The Guarantor's obligations hereunder with respect to any Obligation shall not be affected by the existence, validity, enforceability, perfection, release, or impairment of value of any collateral for such Obligations. The Coral Entities shall not be obligated to file any claim relating to the Obligations owing to it in the event that a Guaranteed Party becomes subject to a bankruptcy, reorganization, or similar proceeding, and the failure of a Coral Entity to so file shall not affect the Guarantor's obligations hereunder. In the event that any payment to a Coral Entity in respect of any Obligations is rescinded or must otherwise be returned in the event that a Guaranteed Party becomes subject to a bankruptcy, reorganization, or similar proceeding, Guarantor shall remain liable hereunder in respect to such Obligations as if such payment had not been made.

5.**Subrogation**. Guarantor waives its right to be subrogated to the rights of the Coral Entities with respect to any Obligations paid or performed by Guarantor until all Obligations have been fully and indefeasibly paid to the Coral Entities or otherwise terminated, subject to no rescission or right of return, and Guarantor has fully and indefeasibly satisfied all of Guarantor's obligations under this Guaranty.

6.**Waivers**. Guarantor hereby waives any circumstance which might constitute a legal or equitable discharge of a surety or guarantor, including but not limited to (a) notice of acceptance of this Guaranty; (b) presentment and demand concerning the liabilities of Guarantor; (c) notice of any dishonor or default by, or disputes with, a Guaranteed Party; and (d) any right to require that any action or proceeding be brought against a Guaranteed Party or any other person, or to require that a Coral Entity seek enforcement of any performance against a Guaranteed Party or any other person, prior to any action against Guarantor under the terms hereof. Guarantor consents to the renewal, compromise, extension, acceleration, or other modification of the terms of a Contract, without in any way releasing or discharging Guarantor from its obligations hereunder. Except as to applicable statute of limitations, the time for bringing any claim under the terms of the Indemnification Agreement and duration of this Guaranty as provided in Section 3 above, no delay of a Coral Entity in the exercise of, or failure to exercise, any rights hereunder shall operate as a waiver of such rights, a waiver of any other rights, or a release of Guarantor from any obligations hereunder.

7.**REPRESENTATIONS**. Guarantor is a corporation duly organized and validly existing under the laws of the State of Washington. The execution, delivery and performance of this Guaranty have been duly authorized by all necessary corporate action on the part of Guarantor. This Guaranty constitutes the legal, valid and binding obligation of Guarantor enforceable against Guarantor in accordance with its terms (except that enforcement may be limited by bankruptcy, insolvency, reorganization, or similar laws affecting the enforcement of creditors' rights generally and general principles of equity, whether considered in a proceeding in equity or at law).

8**Notice**. Any payment demand, notice, correspondence or other document to be given hereunder by any party to another (herein collectively called "Notice") shall be in writing and delivered personally or mailed by certified mail, postage prepaid and return receipt requested, or by facsimile, to the addresses set forth below. Notice given by personal delivery or mail shall be effective upon actual receipt, or, if receipt is refused or rejected, upon attempted delivery. Notice given by facsimile shall be effective upon actual receipt if received during the recipient's normal business hours, or at the beginning of the recipient's next business day after receipt if not received during the recipient's normal business hours. All Notices by facsimile shall be confirmed promptly after transmission in writing by certified mail or personal delivery. Any party may change any address to which Notice is to be given to it by giving Notice as provided above of such change of address.

9.**Miscellaneous**. **THIS GUARANTY SHALL BE IN ALL RESPECTS GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAWS EXCEPT SECTIONS 5-1401 AND 5-1402 OF THE NEW YORK GENERAL OBLIGATIONS LAW.** No term or provision of this Guaranty shall be amended or modified except in a writing signed by Guarantor and each of the Coral Entities. A party may assign its rights and obligations hereunder only with the prior written consent of the Coral Entities, in the case of Guarantor, and Guarantor, in the case of any of the Coral Entities, and any attempted assignment without such prior written consent shall be null and void. Subject to the foregoing, this Guaranty shall be binding upon Guarantor, its successors and assigns, and shall inure to the benefit of and be enforceable by the Coral Entities, their successors and assigns. This Guaranty and the Indemnification Agreement embodies the entire agreement and understanding between Guarantor and the Coral Entities, and supersedes all prior guaranties issued by Guarantor in connection with the Contracts.

IN WITNESS WHEREOF, Guarantor has executed this Guaranty effective as of the date first herein written.

Avista Capital, Inc.

/s/ Malyn K. Malquist

Name: Malyn K. Malquist
Title: Senior Vice President & Chief Financial Officer

Address of: Coral Energy Holding, L.P.
Coral Energy Resources, L.P.
Coral Power, L.L.C.

909 Fannin, Plaza Level 1
Houston, Texas 77010
Attn: Credit Department
Fax No.:

Address of: Coral Energy Canada Inc.

Coral Energy Canada Inc.
3500, 450-1st Street S.W.
Calgary, Alberta Canada
T2P 5H1
Facsimile: 403-716-3501
Attn: Senior Vice President

Address of Guarantor: Avista Capital, Inc.

1411 East Mission Avenue
Spokane, Washington 99202
Attn: General Counsel
Fax No.: (509) 495-4361

Signature Page - Guaranty

Attachment A to Guaranty

1. That certain Purchase and Sale Agreement, dated as of April 16, 2007 (the "**Purchase Agreement**") by and among Avista Energy, Inc., Avista Energy Canada, Ltd., Coral Energy Holding, L.P., Coral Energy Resources, L.P., Coral Power, L.L.C., and Coral Energy Canada Inc.

2. If and when entered into, that certain Agency Agreement, to be dated as of June 30, 2007 (the "**Agency Agreement**") by and among Avista Energy, Inc., Avista Energy Canada, Ltd., Coral Energy Holding, L.P., Coral Energy Resources, L.P., Coral Power, L.L.C., and Coral Energy Canada Inc.

3. That certain Post-Closing Transition Services Agreement dated as of June 30, 2007 (the "**Transition Services Agreement**") by and among Avista Energy, Inc., Avista Energy Canada, Ltd., Coral Energy Holding, L.P., Coral Energy Resources, L.P., Coral Power, L.L.C., and Coral Energy Canada Inc.

4. That certain Energy Conversion Agreement dated as of June 30, 2007 (the "**Lancaster Agreement**") by and between Avista Turbine Power, Inc. and Coral Power, L.L.C.

5. That certain Agreement to Temporarily Assign Rights to Use Jackson Prairie Expansion Capacity dated as of June 30, 2007 (the "**JP Agreement** ") by and between Avista Energy, Inc. and Coral Energy Resources, L.P.

6. Each of the documents and agreements entered into pursuant to any of the foregoing agreements.

Exhibit 10.3

SECURITY AGREEMENT

This SECURITY AGREEMENT dated as of June 30, 2007 (this "Security Agreement") is given by **Avista Capital, Inc.**, a Washington corporation (" Debtor "), in favor of **Coral Energy Holding, L.P** ., a Delaware limited partnership ("Coral"), for the benefit of Coral, **Coral Energy Resources, L.P.** , a Delaware limited partnership, **Coral Power, L.L.C** ., a Delaware limited liability company and **Coral Energy Canada Inc** ., an Alberta corporation (collectively, the " Coral Entities ").

RECITALS

A. Pursuant to that certain Guaranty dated June 30, 2007, Debtor has agreed to guaranty certain Obligations of its affiliates, Avista Energy, Inc., Avista Energy Canada Ltd. and Avista Turbine Power, Inc. to the Coral Entities (the "Guaranty").

B. Debtor has agreed to grant to Coral for the benefit of the Coral Entities a security interest in certain of its property as provided herein.

C. Coral has agreed to act as agent for and on behalf of the Coral Entities for purposes of this Security Agreement.

AGREEMENT

For and in consideration of the promises and the agreements contained in this Agreement and for other good and valuable consideration, the receipt and sufficient of which are hereby acknowledged, the parties agree as follows:

1. Definitions. Capitalized terms used and not otherwise defined herein shall have the meanings ascribed to them as set forth in **Appendix A** attached to and made a part of this Security Agreement. In the absence of such definitions, any other terms used herein (whether or not capitalized) shall have the meaning ascribed to them by the Code to the extent the same are defined in the Code.

2. Grant of Security Interest. Debtor hereby grants to Coral for the benefit of the Coral Entities a first priority security interest in the Collateral to secure the Obligations including, without limitation:

   2.1. the prompt and complete payment of all Obligations;

   2.2. the timely performance and observance by Debtor of all covenants, obligations and conditions contained in the Guaranty; and

   2.3. without limiting the generality of the foregoing and to the fullest extent permitted under applicable law, the payment of all amounts, including without limitation, interest which constitutes part of the Obligations and would be owed by Debtor to one or more of the Coral Entities under the Guaranty but for the fact that they are unenforceable or not allowable due to the existence of a bankruptcy, reorganization or similar proceeding involving Debtor

and Debtor hereby agrees to deliver the Collateral to the Escrow Agent under the Escrow Agreement, to be held by the Escrow Agent as the Escrow Fund under the Escrow Agreement, for the benefit of the Coral Entities. Provided, however, that under no circumstances shall the aggregate of all such obligations secured by this Security Agreement, including the Obligations and any other amounts referred to above, exceed at any time an aggregate value of Twenty-Five Million Dollars ($25,000,000.00).

3. Substitute Collateral. Debtor shall be entitled at any time, and from time to time, to substitute any of the following, in form and substance reasonably acceptable to Coral, as substitute collateral for the Collateral: (a) a cash deposit in an amount equal to Twenty-Five Million Dollars ($25,000,000.00); (b) an irrevocable letter of credit in a face amount equal to Twenty-Five Million Dollars ($25,000,000.00), issued by a U.S. commercial bank or the U.S. branch of a foreign bank, with such bank having a credit rating of at least A- from the Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.) or its successor, or a rating of at least A3 from Moody's Investor Services, Inc. or its successor, or (c) such other form of collateral security as Coral and Debtor may mutually agree upon. Upon completion of any such substitution of collateral, the substitute collateral shall become the "Collateral" hereunder, and Coral shall release, return, surrender, and otherwise terminate any security interest granted hereunder in, the property or instruments previous serving as "Collateral" hereunder.

4. Authorization to File Financing Statements. Debtor authorizes Coral to file with the Department of Licensing for the State of Washington an initial financing statement and continuation statements that (a) indicate the Collateral; and (b) provide any other information required by part 5 of Article 9 of the Code or as required by such other jurisdiction for the sufficiency or filing office acceptance of such financing statement or continuation statement, including whether Debtor is an organization, the type of organization and any organization identification number issued to Debtor. Debtor agrees to furnish any such information to Coral promptly upon the request.

5. Covenants Concerning Debtor's Legal Status. Debtor covenants with Coral as follows:

   5.1. Without providing at least 30 days prior written notice to Coral, Debtor will not change its name, its place of business or, if more than one, chief executive office, or its mailing address or organizational identification number if it has one;

   5.2. If Debtor does not have an organizational identification number and later obtains one, Debtor will promptly notify Coral of such organizational identification number; and

   5.3. Without providing at least 30 days prior written notice to Coral, Debtor will not change its type of organization, jurisdiction of organization or other legal structure.

6. Representations and Warranties Concerning Collateral. Debtor further represents and warrants to Coral as follows:

   6.1. Except for the security interests granted to Coral in this Agreement, Debtor owns good and marketable title to the Collateral free and clear of all Liens, and neither the Collateral nor any interest in the Collateral has been transferred to any other party. Debtor has full right, power and authority to grant a first-priority security interest in the Collateral to Coral in the manner provided in this Security Agreement, free and clear of any other Liens, adverse claims and options and without the consent of any other person or entity or if consent is required, such consent has been obtained. No other Lien, adverse claim or option has been created by Debtor or is known by Debtor to exist with respect to any Collateral; and to the best of Debtor's knowledge and belief no financing statement or other security instrument is on file in any jurisdiction covering such Collateral other than the security interest in favor of Coral under this Security Agreement. The security interest granted is a first lien security interest.

   6.2. There are no actions, suits or proceedings pending or threatened against or affecting the Collateral before any court or by or before any governmental department, commission, board, bureau, agency or instrumentality, domestic or foreign, which in any manner draws into question the validity of this Security Agreement.

7. Covenants Concerning the Collateral.

7.1. Debtor covenants with Coral that while this Security Agreement remains in effect, that except for the security interest herein granted and the deposit of the Collateral with the Escrow Agent under the Escrow Agreement, Debtor is and shall be the owner of or have other transferable rights in the Collateral free from any right or claim of any other person or any Lien, security interest or other encumbrance, and Debtor shall defend the same against all claims and demands of all persons at any time claiming the same or any interest therein adverse to Coral. Debtor shall not pledge, mortgage or create, or suffer to exist any right of any person in or claim by any person to the Collateral, or any security interest, Lien or other encumbrance in the Collateral in favor of any person other than Coral; nor permit any person, other than Coral, to file any financing statement or security interest in the Collateral.

7.2. In the event of (a) a sale, transfer, disposition or reorganization of greater than 50% of the equity of Debtor's subsidiary, Advantage IQ, Inc, a Washington corporation (" Advantage "), (b) Debtor ceasing to own and control shares of stock of and other equity interests in Advantage representing a majority of the votes entitled to be cast by shareholders of Advantage and a majority of the equity value of Advantage, or (c) the sale, transfer or other disposition of the underlying assets of Advantage outside the ordinary course of business, Debtor agrees to replace the Collateral with substitute Collateral as set forth Section 3.

8. Securities and Deposits. Coral may at any time following and during the continuance of an Event of Default, at its option, transfer to itself or any nominee any securities constituting Collateral, receive any income thereon and hold such income as additional Collateral or apply it to the Obligations. Whether or not any Obligations are due, Coral may following and during the continuance of an Event of Default demand, sue for, collect or make any settlement or compromise that it deems desirable with respect to the Collateral.

9. Rights and Remedies. If an Event of Default shall have occurred and is continuing, Coral shall have in any jurisdiction in which enforcement hereof is sought, in addition to all other rights and remedies, the rights and remedies of a secured party under the Code and any additional rights and remedies as may be provided to a secured party in any jurisdiction in which Collateral is located, including, without limitation, the right to take possession of the Collateral.

10. No Waiver by Coral. Coral shall not be deemed to have waived any of its rights and remedies in respect of the Obligations or the Collateral unless such waiver shall be made in writing and signed by Coral. No delay or omission on the part of Coral in exercising any right or remedy shall operate as a waiver of such right or remedy or any other right or remedy. A waiver on any occasion shall not be construed as a bar to or a waiver of any right or remedy on any future occasion. All rights and remedies of Coral with respect to the Obligations or the Collateral, whether evidenced hereby or by any other instrument or papers, may be exercised by Coral, shall be cumulative and may be exercised singularly, alternatively, successively or concurrently at such time or at such times as Coral deems expedient.

11. Marshalling. Subject to the terms and conditions of this Security Agreement and the Indemnification Agreement, Coral shall not be required to marshal the Collateral, or other assurances of payment of the Obligations, or any of them or to resort to the Collateral or other

assurance of payment in any particular order, and all of the rights and remedies hereunder and in respect of the Collateral and other assurances of payment shall be cumulative and in addition to all other rights and remedies, however existing or arising. **TO THE EXTENT THAT IT LAWFULLY MAY, DEBTOR HEREBY AGREES THAT IT WILL NOT INVOKE ANY LAW RELATING TO THE MARSHALLING OF COLLATERAL WHICH MIGHT CAUSE DELAY IN OR IMPEDE THE ENFORCEMENT OF CORAL'S RIGHTS AND REMEDIES UNDER THIS SECURITY AGREEMENT OR UNDER ANY OTHER INSTRUMENT CREATING OR EVIDENCING ANY OF THE OBLIGATIONS OR UNDER WHICH ANY OF THE OBLIGATIONS IS OUTSTANDING OR BY WHICH ANY OF THE OBLIGATIONS IS SECURED OR PAYMENT THEREOF IS OTHERWISE ASSURED, AND, TO THE EXTENT THAT IT LAWFULLY MAY, DEBTOR HEREBY IRREVOCABLY WAIVES THE BENEFITS OF ALL SUCH LAWS.**

12. Overdue Amounts. Until paid, all amounts due and payable by Debtor hereunder shall be a debt secured by the Collateral and shall bear, whether before or after judgment, interest determined by reference to the U.S. Dollar London Interbank Offer Rate (LIBOR) quoted on Bloomberg page BBAM applicable for the relevant one-month period (or any successor or substitute page of such publication, or any successor to or substitute for such publication, providing rate quotations comparable to those currently provided on such page or such publication) at approximately 11:00 a.m., London time, two Business Days prior to the commencement of such interest period.

13. Notices. All communications hereunder shall be in writing and may be delivered by hand delivery, United States mail, overnight courier service or facsimile. Notice by facsimile or hand delivery shall be effective on the day actually received, if received during business hours on a Business Day, and otherwise shall be effective at the beginning of the recipient's next Business Day. Notice by overnight United States mail or courier shall be effective on the next Business Day after it was sent to the appropriate notice address set forth below or at such other address as any party hereto may have furnished to the other party in writing:

If to the Coral Entities:

909 Fannin, Plaza Level 1
Houston, Texas 77010
Attn: General Counsel
Phone: (713) 767-5400
Fax: (713) 230-2900

If to Debtor:

Avista Capital, Inc.
1411 East Mission Avenue
Spokane, Washington 99202
Attention: General Counsel
Phone: (509) 495-8687
Facsimile: (509) 495-4316

14. Governing Law; Consent to Jurisdiction. **THIS SECURITY AGREEMENT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK, WITHOUT REFERENCE TO ITS CONFLICT OF LAWS PROVISIONS EXCEPT SECTIONS 5-1401 AND 5-1402 OF THE NEW YORK GENERAL OBLIGATIONS LAW** .

15. Term of Agreement. This grant of a security interest under this Security Agreement shall remain in full force until the later of January 1, 2009 or, in the event that any of the Coral Entities has made a claim under the Indemnification Agreement, the date such claim has been resolved and such amount owing, if any, has been paid. Upon expiration of this Security Agreement, Coral shall promptly return possession of the Collateral, if it then has possession of the same, to Debtor and file any applicable termination statements. Notwithstanding the foregoing, this Security Agreement shall continue notwithstanding the reorganization or bankruptcy of Debtor, or any other similar event or proceeding affecting Debtor.

16. Miscellaneous. The headings of each section of this Security Agreement are for convenience only and shall not define or limit the provisions thereof. This Security Agreement and all rights and obligations hereunder shall be binding upon Debtor and its successors and assigns and shall insure to the benefit of the Coral Entities and their successors and assigns. No party may assign its interest in this Security Agreement without the prior written consent of Coral, in the case of Debtor, and Debtor, in the case of the Coral Entities. If any term of this Security Agreement shall be held to be invalid, illegal or unenforceable, the validity of all of the other terms shall in no way be affected and this Security Agreement shall be construed and enforceable as if such invalid, illegal or unenforceable term had not be included herein. This Security Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

17. Interpretation and Construction. In interpreting and construing this Security Agreement, the following principles shall be followed:

17.1. examples shall not be construed to limit, expressly or by implication, the matter they illustrate;

17.2. the terms “herein,” “hereof,” “hereby,” and “hereunder,” or other similar terms, refer to this Security Agreement as a whole and not only to the particular article, section or other subdivision in which any such terms may be employed;

17.3. references to sections and other subdivisions refer to the sections and other subdivisions of this Security Agreement;

17.4. the word “includes” and its syntactical variants mean “includes, but is not limited to” and corresponding syntactical variant expressions and the term “and/or” shall mean “or”;

17.5. whenever this Security Agreement refers to a number of days, such number shall refer to calendar days unless Business Days are specified;

17.6. the plural shall be deemed to include the singular, and vice versa; and

17.7. each exhibit, annex, attachment, and schedule to this Security Agreement is a part of this Security Agreement, but if there is any conflict or inconsistency between the main body of this Security Agreement and any exhibit, annex, attachment, or schedule, the provisions of the main body of this Security Agreement shall prevail.

*****

IN WITNESS WHEREOF, intending to be legally bound, Debtor has caused this Security Agreement to be executed as of the date first written above.

Avista Capital, Inc.

BY: **/S/ Malyn L. Malquist**
Name: **Malyn L. Malquist**
Title: **Senior Vice President & Chief Financial Officer**

Coral Energy Holding, L.P.

BY: **/S/ Beth A. Bowman**
Name: **Beth A. Bowman**
Title: **Senior Vice President**

APPENDIX A TO SECURITY AGREEMENT
DEFINITIONS

"Business Day" means any day other than a Saturday, Sunday or any day in which commercial banks in Houston, Texas are required or permitted by law to be closed and the Friday following the Thanksgiving holiday.

"Code" means the Uniform Commercial Code as currently in effect and as may be amended from time to time, in the State of New York.

"Collateral" means 13,770,285 of shares of common stock of Advantage (defined and described in Section 7.2 of this Security Agreement), which represents with respect to Advantage (a) 49.96% of its common stock and 46.53% of all of its equity interests, on an as-converted basis, currently outstanding, and (b) 38.68% of all of its equity interests calculated on an as-converted and fully diluted basis, in each case as measured by vote and value.

"Coral" has the meaning ascribed to it in the preface.

"Coral Entities" has the meaning ascribed to it in the preface.

"Debtor" has the meaning ascribed to it in the preface.

"Escrow Agreement" means that certain Escrow Agreement of even date herewith entered into by and among Coral, Debtor and Avista Corporation, as escrow agent (the " Escrow Agent "), for the purposes of establishing an escrow fund (the " Escrow Fund ") consisting of the Collateral.

"Event of Default" means:

a. Any default or event of default under the Guaranty;

b. Any representation or warranty made by Debtor herein is false or misleading in any material respect when made;

c. Debtor's failure to comply with any of the provisions of this Security Agreement and such failure remains unremedied for three (3) Business Days after written notice thereof has been given to Debtor;

d. The transfer or disposition of any of the Collateral, except as expressly permitted by this Security Agreement;

e. The attachment, execution or levy on any of the Collateral, except as expressly permitted by this Security Agreement;

f. Debtor voluntarily or involuntarily becomes subject to any proceeding under any bankruptcy or insolvency statute; or

g. Debtor fails to comply with or becomes subject to any administrative or judicial proceeding under any federal, state or local (a) asset forfeiture or similar law which can result in the forfeiture of property; or (b) other law, where noncompliance may have any significant effect on the Collateral.

"Indemnification Agreement" means that certain Indemnification Agreement of even date herewith entered into by and among Avista Energy, Inc., Avista Energy Canada, Ltd., Avista Turbine Power, Inc. and the Coral Entities.

"Lien" means any mortgage, pledge, security interest, encumbrance, lien, claim or charge of any kind, whether or not filed, recorded or otherwise perfected under applicable law.

"Obligations" means all of the indebtedness, obligations and liabilities of Debtor to the Coral Entities arising or accruing under the Guaranty.

"Security Agreement" has the meaning ascribed to it in the preface.

EXHIBIT 12

AVISTA CORPORATION

Computation of Ratio of Earnings to Fixed Charges and Preferred Dividend Requirements
Consolidated
(Thousands of Dollars)

	12 months ended June 30, 2007	Years Ended December 31			
		2006	2005	2004	2003
Fixed charges, as defined:					
Interest expense	$ 85,150	$ 88,426	$ 84,952	$ 84,746	$ 85,013
Amortization of debt expense and premium - net	7,157	7,741	7,762	8,301	7,972
Interest portion of rentals	1,686	1,802	2,394	2,443	4,452
Total fixed charges	$ 93,993	$ 97,969	$ 95,108	$ 95,490	$ 97,437
Earnings, as defined:					
Income from continuing operations	$ 56,187	$ 72,941	$ 44,988	$ 35,453	$ 50,643
Add (deduct):					
Income tax expense	31,877	41,986	25,764	21,506	35,340
Total fixed charges above	93,993	97,969	95,108	95,490	97,437
Total earnings	$ 182,057	$ 212,896	$ 165,860	$ 152,449	$ 183,420
Ratio of earnings to fixed charges	1.94	2.17	1.74	1.60	1.88
Fixed charges and preferred dividend requirements:					
Fixed charges above	$ 93,993	$ 97,969	$ 95,108	$ 95,490	$ 97,437
Preferred dividend requirements (1)	—	—	—	—	1,910
Total	$ 93,993	$ 97,969	$ 95,108	$ 95,490	$ 99,347
Ratio of earnings to fixed charges and preferred dividend requirements	1.94	2.17	1.74	1.60	1.85

(1) Preferred dividend requirements have been grossed up to their pre-tax level. Effective July 1, 2003, preferred dividends are included in interest expense with the adoption of SFAS No. 150.

Exhibit 15

August 8, 2007

Avista Corporation
Spokane, Washington

We have reviewed, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the unaudited interim financial information of Avista Corporation and subsidiaries for the periods ended June 30, 2007 and 2006, as indicated in our report dated August 6, 2007; because we did not perform an audit, we expressed no opinion on that information.

We are aware that our report referred to above, which is included in your Quarterly Report on Form 10-Q for the quarter ended June 30, 2007, is incorporated by reference in Registration Statement Nos. 2-81697, 2-94816, 033-54791, 333-03601, 333-22373, 333-58197, 033-32148, 333-33790, 333-47290, and 333-126577 on Form S-8, in Registration Statement Nos. 333-106491, 033-53655, 333-39551, 333-82165, 333-63243, 333-16353, 333-16353-01, 333-16353-02, 333-16353-03, 333-64652, 033-60136, 333-10040, 333-113501, and 333-139239 on Form S-3, and in Registration Statement Nos. 333-62232 and 333-82502 on Form S-4, and in AVA Formation Corp.'s Registration Statement No. 333-131872 on Form S-4.

We also are aware that the aforementioned report, pursuant to Rule 436(c) under the Securities Act of 1933, is not considered a part of the Registration Statement prepared or certified by an accountant or a report prepared or certified by an accountant within the meaning of Sections 7 and 11 of that Act.

/s/ Deloitte & Touche LLP

Seattle, Washington

Exhibit 31.1

CERTIFICATION

I, Gary G. Ely, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Avista Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 8, 2007

/s/ Gary G. Ely

Gary G. Ely
Chairman of the Board and
Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Malyn K. Malquist, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 8, 2007

/s/ Malyn K. Malquist

Malyn K. Malquist
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

Exhibit 32

AVISTA CORPORATION

CERTIFICATION OF CORPORATE OFFICERS
(Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)

Each of the undersigned, Gary G. Ely, Chairman of the Board and Chief Executive Officer of Avista Corporation (the “Company”), and Malyn K. Malquist, Executive Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 8, 2007

/s/ Gary G. Ely

Gary G. Ely
Chairman of the Board and
Chief Executive Officer

/s/ Malyn K. Malquist

Malyn K. Malquist
Executive Vice President and
Chief Financial Officer

Form 10-K

AVISTA CORP - ava

Filed: February 27, 2008 (period: December 31, 2007)

Annual report which provides a comprehensive overview of the company for the past year

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AVISTA CORPORATION

PART I

Our Annual Report on Form 10-K contains forward-looking statements, which should be read with the cautionary statements and important factors included at "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Forward-Looking Statements" on pages 23-24. Forward-looking statements are all statements except those of historical fact, including, without limitation, those that are identified by the use of words that include "will," "may," "could," "should," "intends," "plans," "seeks," "anticipates," "estimates," "expects," "forecasts," "projects," "predicts," and similar expressions. Forward-looking statements are subject to a variety of risks and uncertainties and other factors. Many of these factors are beyond our control and could have a significant effect on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in our statements.

Available Information

Our Web site address is www.avistacorp.com. We make annual, quarterly and current reports available at our Web site as soon as practicable after electronically filing these reports with the Securities and Exchange Commission. Information contained on our Web site is not part of this report.

Item 1. Business

Company Overview

Avista Corporation (Avista Corp. or the Company), incorporated in the state of Washington in 1889, is an energy company engaged in the generation, transmission and distribution of energy as well as other energy-related businesses. As of December 31, 2007, we employed 1,473 people in our utility operations and 644 people in our subsidiary businesses. Our corporate headquarters are in Spokane, Washington, the hub of the Inland Northwest. Agriculture, mining and lumber were the primary industries in the Inland Northwest for many years; today health care, education, finance, electronic and other manufacturing, tourism and the service sectors are growing in importance.

In May 2006, our shareholders approved a proposal to proceed with a statutory share exchange, which would change our organization to a holding company structure. If the implementation of the holding company structure is approved by regulators on terms acceptable to us, it may be completed sometime in 2008. Further information is available at "Note 26 of the Notes to Consolidated Financial Statements."

We have three reportable business segments as follows:

- **Avista Utilities** – an operating division of Avista Corp. comprising our regulated utility operations that started in 1889. Our utility generates, transmits and distributes electricity and distributes natural gas. The utility also engages in wholesale purchases and sales of electricity and natural gas.

- **Energy Marketing and Resource Management** – electricity and natural gas marketing, trading and resource management. The activities of this business segment were conducted primarily by Avista Energy, Inc. (Avista Energy), an indirect subsidiary of Avista Corp. On June 30, 2007, Avista Energy and Avista Energy Canada, Ltd. (Avista Energy Canada) completed the sale of substantially all of their contracts and ongoing operations to Shell Energy North America (U.S.), L.P. (Shell Energy), formerly known as Coral Energy Holding, L.P., as well as to certain other subsidiaries of Shell Energy. Completion of this transaction effectively ends the majority of the operations of this business segment. This segment still owns natural gas storage facilities and has operating revenues and resource costs related to the power purchase agreement for a 270 megawatt (MW) natural gas-fired combined cycle combustion turbine plant located in Idaho (Lancaster Plant). The Lancaster Plant is owned by an unrelated third-party and all of the output from the plant is contracted to Avista Energy through 2026. The majority of the rights and obligations of the power purchase agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010, we expect these rights and obligations will be transferred to Avista Utilities, subject to future regulatory approval. The operations of Avista Power, LLC (Avista Power), which are not significant to our overall operations at this time and are not expected to be in the future, are also included in this segment. Avista Power, through its equity investment in Rathdrum Power, LLC (RP LLC) was a 49 percent owner of the Lancaster Plant. In October 2006, Avista Power completed the sale of its investment in RP LLC for close to book value.

- **Advantage IQ** – a provider of facility information and cost management services for multi-site customers throughout North America. This segment's primary product lines include consolidated billing, resource accounting, energy analysis and load profiling services. The activities of this business segment are conducted by Advantage IQ, Inc. (Advantage IQ), an indirect subsidiary of Avista Corp.

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Future Resource Needs

We have operational strategies to provide sufficient resources to meet our energy requirements under a range of operating conditions. These operational strategies consider the amount of energy needed over hourly, daily, monthly and annual durations, which vary widely because of the factors that influence demand. The following is a forecast of our average annual energy requirements and resources for 2008, 2009, 2010 and 2011:

Forecasted Electric Energy Requirements and Resources
(aMW)

	2008	2009	2010	2011
Requirements:				
System load	1,105	1,118	1,141	1,161
Contracts for power sales	136	141	140	140
Total requirements	1,241	1,259	1,281	1,301
Resources:				
Company-owned and contract hydro generation (1)	541	540	526	524
Company-owned base load thermal generation (2)	258	242	246	256
Company-owned other thermal generation (2)	273	285	282	272
Contracts for power purchases	370	387	625	542
Total resources	1,442	1,454	1,679	1,594
Surplus resources	201	195	398	293
Additional available energy (3)	134	142	142	142
Total surplus resources	335	337	540	435

(1) The forecast assumes near normal hydroelectric generation of 541 aMW for 2008, 540 aMW for 2009, 526 aMW for 2010 and 524 aMW for 2011 (decline is related to changes in contracts with PUDs).

(2) Excludes the Northeast CT and Rathdrum CT. We generally only use these resources to meet electric load requirements due to either below normal hydroelectric generation or increased loads or outages at other generating facilities, and/or when operating costs are lower than short-term wholesale market prices.

(3) Northeast CT and Rathdrum CT. The combined maximum capacity of the Northeast CT and Rathdrum CT is 243 MW, with estimated available energy production as indicated for each year.

In September 2007, we submitted our 2007 Electric Integrated Resource Plan (IRP) to the WUTC and the IPUC. The IRP identifies a strategic resource portfolio that meets future electric load requirements, promotes environmental stewardship and meets our obligation to provide reliable electric service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project. Our preferred resource plan, which is part of the IRP, includes the addition of the following resources by 2017:

- 350 MW of natural gas generation,
- 300 MW of wind power,
- 87 MW of conservation,
- 38 MW of hydroelectric generation plant upgrades, and
- 35 MW of other renewable generation.

In response to new laws in the state of Washington regarding renewable resources and greenhouse gas emissions, the IRP eliminates coal-based generation as a new resource. The amount of renewable resources in our future IRPs could change if the cost effectiveness of those resources changes.

All of the output from the Lancaster Plant is contracted to Avista Energy through 2026 under a power purchase agreement. Avista Energy assigned the majority of its rights and obligations under this agreement to Shell Energy through the end of 2009. Beginning in 2010, we expect that these rights and obligations will be transferred to our utility operations, subject to future approval by the WUTC and the IPUC.

We are close to completing the acquisition of a wind generation site. We expect to construct a 50 MW generation facility in 2010 or 2011 at an estimated cost of approximately $120 million.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Issues and Other Contingencies" for information with respect to a recently enacted law, as well as potential legislation that could influence our future electric resource mix.

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Business Segments

We have three reportable business segments as follows:

- **Avista Utilities** – generation, transmission and distribution of electric energy and distribution of natural gas to retail customers, as well as wholesale purchases and sales of energy commodities. Avista Utilities is an operating division of Avista Corp. comprising our regulated utility operations.

- **Energy Marketing and Resource Management** – electricity and natural gas marketing, trading and resource management. The activities of this business segment were conducted primarily by Avista Energy, Inc. (Avista Energy), an indirect subsidiary of Avista Corp. On June 30, 2007, Avista Energy and Avista Energy Canada, Ltd. (Avista Energy Canada) completed the sale of substantially all of their contracts and ongoing operations to Shell Energy North America (U.S.), L.P. (Shell Energy), formerly known as Coral Energy Holding, L.P., as well as to certain other subsidiaries of Shell Energy. Completion of this transaction effectively ends the majority of the operations of this business segment. This segment still owns natural gas storage facilities and has operating revenues and resource costs related to the power purchase agreement for a 270 megawatt (MW) natural gas-fired combined cycle combustion turbine plant located in Idaho (Lancaster Plant). The Lancaster Plant is owned by an unrelated third-party and all of the output from the plant is contracted to Avista Energy through 2026. The majority of the rights and obligations of the power purchase agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010, we expect these rights and obligations will be transferred to Avista Utilities, subject to future regulatory approval.

- **Advantage IQ** – facility information and cost management services for multi-site customers. The activities of this business segment are conducted by Advantage IQ, Inc. (Advantage IQ), an indirect subsidiary of Avista Corp.

We have other businesses including sheet metal fabrication, venture fund investments and real estate investments. These activities are conducted by various indirect subsidiaries of Avista Corp., including Advanced Manufacturing and Development (AM&D), doing business as METALfx. These activities are not a reportable business segment.

Avista Energy, Advantage IQ and the various other companies are subsidiaries of Avista Capital, Inc. (Avista Capital), which is a direct, wholly owned subsidiary of Avista Corp. Our total common stockholders' equity was $914.0 million as of December 31, 2007, of which $71.4 million represented our investment in Avista Capital. Our investment in Avista Capital decreased significantly in 2007 primarily due to the sale of substantially all of Avista Energy's contracts and ongoing operations and the subsequent dividends to Avista Corp. through Avista Capital.

The following table presents net income (loss) for each of our business segments (and the other businesses) for the year ended December 31 (dollars in thousands):

	2007	2006	2005
Avista Utilities	$ 43,822	$ 57,794	$ 52,299
Energy Marketing and Resource Management	(11,877)	11,567	(8,621)
Advantage IQ	6,651	6,255	3,922
Other	(121)	(2,675)	(2,612)
Net income	$ 38,475	$ 72,941	$ 44,988

Executive Level Summary

Overall

Our operating results and cash flows have been derived primarily from:

- regulated utility operations (Avista Utilities),
- energy trading, marketing and resource management activities (Avista Energy in the Energy Marketing and Resource Management segment), and
- facility information and cost management services for multi-site customers (Advantage IQ).

2007 was a year of repositioning our company with a focus on the future of our utility operations. Moody's Investors Service and Standard & Poor's recently upgraded our credit ratings, which resulted in an investment grade rating for our senior unsecured debt and corporate rating from each of these rating agencies. The upgrade reflects several steps taken over the past few years to lower our business risk profile and improve financial metrics. The most recent significant steps were the sale of substantially all of Avista Energy's contracts and ongoing operations and our general rate case settlement in Washington.

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Although we are pleased with the upgrades, it is important to note that we are at the lower end of the investment grade category and will continue to work towards improving our ratings. We intend to continue to focus on improving earnings and operating cash flows, controlling costs, reducing debt and debt service costs, while working to improve our credit ratings.

After closing costs and other adjustments, the Avista Energy transaction resulted in a pre-tax loss of $4.3 million. Proceeds from the transaction included cash consideration for the net assets acquired by Shell Energy and liquidation of the net current assets of Avista Energy not sold to Shell Energy (primarily receivables, restricted cash and deposits with counterparties). The majority of the $169 million of proceeds from the transaction were deployed into our regulated utility operations. Also, we retained natural gas storage rights and facilities for the period subsequent to April 2011 and the power purchase agreement for the Lancaster Plant for the period 2010 through 2026. We plan to use these assets and contracts in our utility operations, subject to future regulatory approval. The completion of this transaction lowers our corporate risk profile and should improve the stability of our earnings.

Our net income was $38.5 million for 2007 compared to $72.9 million for 2006. This decrease was primarily due to the net loss at Avista Energy (Energy Marketing and Resource Management segment) and lower earnings at Avista Utilities.

Avista Utilities

Avista Utilities is our most significant business segment. Our utility operating and financial performance is dependent upon, among other things:

- weather conditions,
- the price of natural gas in the wholesale market, including the effect on the price of fuel for generation,
- the price of electricity in the wholesale market, including the effects of weather conditions, natural gas prices and other factors affecting supply and demand, and
- regulatory decisions, allowing our utility to recover costs, including purchased power and fuel costs, on a timely basis, and to earn a fair return on investment.

Weather has a significant effect on our utility operations. Weather can impact customer demand and operating revenues and we normally have our highest retail (electric and natural gas) energy sales during the winter heating season in the first and fourth quarters of the year. We also have high electricity demand for air conditioning during the summer (third quarter). In general, warmer weather in the heating season and cooler weather in the cooling season will reduce operating revenues. In addition, below normal precipitation (particularly winter snowpack) and other streamflow conditions can negatively impact electric resource costs by decreasing hydroelectric generation capability and increasing our reliance on market purchases and thermal generation. Regional precipitation and snowpack conditions typically have a significant effect on the wholesale price of electricity. In addition, high demand for electricity will generally increase both the quantity needed and price of fuel for electric generation and wholesale electric market prices.

Our hydroelectric generation was 96 percent of normal in 2007. Our hydroelectric generation was below normal (based on a 70-year average) for six of the past eight years. For 2008, we forecast hydroelectric generation to be slightly above normal. This 2008 forecast will be revised based on precipitation, temperatures and other variables during the year.

We are subject to electric and natural gas commodity price risk. In general, price risk is driven by fluctuation in the market price of the commodity needed, held or traded. Changes in energy commodity prices have a significant effect on our liquidity, as well as the market value of derivative assets and liabilities. We have regulatory mechanisms in place that provide for the deferral and recovery of the majority of power and natural gas supply costs. However, if prices increase above the level currently recovered in retail rates during periods when we must purchase energy, power and natural gas deferral balances will increase. This would negatively affect our operating cash flows and liquidity until such costs are recovered from customers.

The decision of the Washington Utilities and Transportation Commission (WUTC) in late 2006 to deny our request for more timely recovery of transmission and generation investments presented a significant challenge in 2007 for us to replace the rate relief we had anticipated. Our challenge was compounded by below normal hydroelectric generation. However, the WUTC approved rate relief for 2008 as discussed below.

Our utility net income was $43.8 million for 2007, a decrease from $57.8 million for 2006 primarily due to a decrease in gross margin (operating revenues less resource costs). The decrease was also due to the disallowance of our net income by an estimated $2.2 million for 2006. Our net loss for 2005 for this segment was due to losses in Avista Energy's natural gas portfolio. Our net loss for 2005 for this segment was reduced by an estimated $0.4 million due to the effects of differences between the estimated market value and the required accounting for certain energy contracts and physical assets under management of Avista Energy.

Analysis of operating revenues and resource costs for 2007 compared to 2006

Operating revenues decreased $116.0 million to $61.5 million primarily due to a decrease of $60.3 million in net trading margin on contracts accounted for under SFAS No. 133 and a $63.2 million decrease from sales of natural gas to commercial and industrial end-user customers (both through Avista Energy Canada and to Montana customers). This category of revenues decreased significantly in 2007 with the sale of substantially all of Avista Energy's contracts and ongoing operations on June 30, 2007.

Resource costs decreased $75.5 million primarily due to decreased resource costs related to sales of natural gas to commercial and industrial end-user customers, and a change in natural gas inventory. This category of expenses decreased significantly in 2007 with the sale of substantially all of Avista Energy's contracts and ongoing operations on June 30, 2007.

Our gross margin (operating revenues less resource costs) from Avista Energy was a loss of $7.1 million for 2007 compared to a gain of $33.4 million for 2006. The decrease was primarily due to underperformance on the power side of the business, losses on the power purchase agreement for the Lancaster Plant, and the difference between the estimated market value and the required accounting for certain contracts and physical assets under management.

The remaining operating revenues and resource costs for this segment primarily represent payments for the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of this agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010 through 2026, the rights and obligations of the power purchase agreement for the Lancaster Plant will be contracted to Avista Energy. We expect that these rights and obligations will be transferred to our regulated utility, subject to future approval by the WUTC and the IPUC.

Analysis of operating revenues and resource costs for 2006 compared to 2005

Operating revenues from this segment increased $10.1 million and resource costs decreased $21.3 million resulting in an increase in our gross margin of $31.4 million.

Operating revenues increased primarily due to an increase of $32.6 million in net trading margin on contracts accounted for under SFAS No. 133, partially offset by decreased revenues of:

- $3.9 million from sales of natural gas to commercial and industrial end-user customers (a decrease through Avista Energy Canada offset by an increase in revenues from Montana customers), and
- $19.4 million under the Agency Agreement with Avista Utilities as natural gas procurement operations were transitioned to Avista Utilities effective April 1, 2005.

Resource costs decreased primarily due to decreased resource costs:

- under the Agency Agreement with Avista Utilities,
- related to sales of natural gas to commercial and industrial end-user customers (a decrease through Avista Energy Canada, partially offset by increases for Montana customers), and
- for transportation and transmission costs.

This was partially offset by a change in natural gas inventory.

Our gross margin (operating revenues less resource costs) from Avista Energy was a gain of $33.4 million for 2006 compared to $2.0 million for 2005. The increase was primarily due to:

- unrealized losses associated with the accounting for our management of natural gas inventory in 2005, and
- improved results from our natural gas trading activities (which had significant losses in 2005).

Our net realized gains from Avista Energy decreased to $31.9 million for 2006 from $40.1 million for 2005. The decrease in our net realized gains was primarily due to:

- decreased net gains on physical electric transactions, and
- increased net losses on settled financial transactions.

This was partially offset by decreased net losses on physical natural gas transactions.

Our total mark-to-market adjustment from this segment was a net unrealized gain of $1.5 million for 2006 compared to a net unrealized loss of $38.1 million for 2005.

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(2) Represents our estimate of interest payments on long-term debt, which is calculated based on the assumption that all debt is outstanding until maturity. Interest on variable rate debt is calculated using the rate in effect at December 31, 2007.

(3) At December 31, 2007, we did not have any borrowings outstanding on our $320 million revolving line of credit.

(4) Represents $85 million outstanding under our revolving $85 million accounts receivable sales financing facility.

(5) Energy purchase contracts were entered into as part of the obligation to serve our retail natural gas and electric customers' energy requirements. As a result, costs are generally recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost adjustment mechanisms.

(6) Includes the interest component of the lease obligation. Future capital lease obligations are not material.

(7) Represents operational agreements, settlements and other contractual obligations with respect to generation, transmission and distribution facilities. These costs are generally recovered through base retail rates.

(8) Pursuant to the settlement of litigation (See "Montana Public School Trust Fund Lawsuit" in "Note 25 of the Notes to Consolidated Financial Statements" for further information), we agreed to make lease payments to the state of Montana in the initial amount of $4 million per year beginning in 2008, and continuing through calendar year 2016. Payments beyond 2008 will be adjusted each year by the Consumer Price Index, which has not been estimated as part of our obligation. On or before June 30, 2016, we will meet with the state of Montana to determine whether the annual lease payments remain consistent with the principles of law as applied to the facts and negotiate an adjusted lease payment for the remaining term of our FERC license for our hydroelectric facilities on the Clark Fork River (expires in 2046). Our obligation assumes no adjustment to our lease payments.

(9) Represents our estimated cash contributions to the pension plan through 2012. We cannot reasonably estimate pension plan contributions beyond 2012 at this time. The new funding rules under the Pension Act could increase our minimum required cash contributions in excess of the $15 million we plan to contribute to the pension plan in each year.

(10) These contractual commitments are primarily related to the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of this agreement were assigned by Avista Energy to Shell Energy through the end of 2009. Beginning in 2010 through 2026, the rights and obligations of the power purchase agreement for the Lancaster Plant are contracted to Avista Energy. We expect these rights and obligations will be transferred to our regulated utility, subject to future approval by the WUTC and the IPUC.

These contractual obligations do not include income tax payments, including any payments related to uncertain tax positions. The timing of the payments on uncertain tax positions is not reasonably determinable.

In addition to the contractual obligations disclosed above, we will incur additional operating costs and capital expenditures in future periods for which we are not contractually obligated as part of our normal business operations.

Competition

Our utility electric and natural gas distribution business has historically been recognized as a natural monopoly. In each regulatory jurisdiction, our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are determined on a "cost of service" basis. Rates are designed to provide, after recovery of allowable operating expenses and capital investments, an opportunity for us to earn a reasonable return on investment as set by our regulators.

In retail markets, we compete with various rural electric cooperatives and public utility districts in and adjacent to our service territories in the provision of service to new electric customers. Alternate providers of energy may also compete with us for sales to existing customers. Similarly, our natural gas distribution operations compete with other energy sources including heating oil, propane and other fuels.

In wholesale markets, competition for available electric resources can be critical to utilities as surplus power resources are absorbed by load growth. The Energy Policy Act of 1992 (1992 Energy Act) removed certain barriers to a competitive wholesale market. The 1992 Energy Act expanded the authority of the FERC to issue orders requiring electric utilities to:

- transmit power and energy to or for wholesale purchasers and sellers, and
- enlarge or construct additional transmission capacity for the purpose of providing these services.

Participants in the wholesale energy markets include:

- other utilities,
- federal power marketing agencies,
- energy marketing and trading companies,

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NOTE 3. DISPOSITION OF AVISTA ENERGY

On June 30, 2007, Avista Energy and Avista Energy Canada completed the sale of substantially all of their contracts and ongoing operations to Shell Energy North America (U.S.), L.P. (Shell Energy), formerly known as Coral Energy Holding, L.P., as well as to certain other subsidiaries of Shell Energy.

As consideration for the assets acquired (net of liabilities assumed), the purchase price paid by Shell Energy was calculated on the closing date as the sum of the following:

- the net trade book value of contracts acquired,
- the market value of the natural gas inventory, and
- the net book value of the tangible fixed assets acquired.

Proceeds from the transaction included cash consideration for the net assets acquired by Shell Energy and the liquidation of the remaining net current assets of Avista Energy not sold to Shell Energy (primarily receivables, restricted cash and deposits with counterparties). On July 2, 2007, Avista Energy received $34.4 million from Shell Energy based on the value of the net assets sold as of May 31, 2007. This amount was adjusted and Avista Energy paid Shell Energy $4.5 million on August 2, 2007 based on the determination of final market values and other closing adjustments as of June 30, 2007. The pre-tax net loss on the transaction was $4.3 million, which is included in non-utility other operating expenses in the Consolidated Statements of Income for 2007.

Assets and liabilities excluded from the sale and retained or liquidated by Avista Energy include:

- cash,
- certain agreements, including electric transmission, natural gas transportation and a power purchase agreement, related to a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho (Lancaster Plant), for periods after December 31, 2009 through 2026,
- storage rights at a natural gas facility located in Washington (Jackson Prairie) for periods after April 30, 2011,
- accounts receivable,
- accounts payable,
- tax obligations,
- cash deposits with and from counterparties,
- litigation matters (including matters related to western energy markets), and
- certain employment agreements and employee related obligations.

Certain assets of Avista Energy with a net book value of approximately $30 million have not been liquidated. These primarily include natural gas storage and deferred tax assets. The Company expects that the natural gas storage will ultimately be transferred to Avista Utilities, subject to future regulatory approval. The Company also expects that the power purchase agreement for the Lancaster Plant for the period 2010 through 2026 will be transferred to Avista Utilities, subject to future regulatory approval.

In connection with the transaction, on June 30, 2007, Avista Energy and its affiliates entered into an Indemnification Agreement with Shell Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Shell Energy each agree to provide indemnification of the other and the other's affiliates for certain events and matters described in the purchase and sale agreement entered into on April 16, 2007 and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the western energy markets in 2000 and 2001 (see Note 25), existing litigation, tax liabilities, matters with respect to storage rights at Jackson Prairie, and any potential issues associated with the power purchase agreement for the Lancaster Plant. In general, such indemnification is not required unless and until a party's claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy's obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of $30 million plus certain fees and expenses. Avista Capital granted Shell Energy a security interest in 50 percent of Avista Capital's common shares of Advantage IQ as collateral for its Guaranty. The aggregate obligations secured by this security interest will in no event exceed $25 million. Avista Capital may substitute collateral, such as cash or letters of credit, in place of the security interest in Advantage IQ's common shares. This security interest in Advantage IQ's common shares will terminate in 18 months (December 31, 2008) except to the extent of claims actually made prior to expiration of the 18-month period. The Guaranty will terminate April 30, 2011 except with respect to claims made prior to termination.

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All of the energy purchase contracts were entered into as part of Avista Utilities' obligation to serve its retail natural gas and electric customers' energy requirements. As a result, these costs are generally recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost deferral and recovery mechanisms.

In addition, Avista Utilities has operational agreements, settlements and other contractual obligations for its generation, transmission and distribution facilities. The expenses associated with these agreements are reflected as other operating expenses in the Consolidated Statements of Income. The following table details future contractual commitments for these agreements (dollars in thousands):

	2008	2009	2010	2011	2012	Thereafter	Total
Contractual obligations	$ 15,207	$ 15,234	$ 15,262	$ 15,291	$ 15,322	$ 167,144	$ 243,460

Avista Utilities has fixed contracts with certain Public Utility Districts (PUD) to purchase portions of the output of certain generating facilities. Although Avista Utilities has no investment in the PUD generating facilities, the fixed contracts obligate Avista Utilities to pay certain minimum amounts (based in part on the debt service requirements of the PUD) whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in utility resource costs in the Consolidated Statements of Income. Expenses under these PUD contracts were $18.0 million in 2007, $13.1 million in 2006 and $9.0 million in 2005. Information as of December 31, 2007 pertaining to these PUD contracts is summarized in the following table (dollars in thousands):

		Company's Current Share of				
	Output	Kilowatt Capability	Annual Costs (1)	Debt Service Costs (1)	Bonds Outstanding	Expira-tion Date
Chelan County PUD:						
Rocky Reach Project	2.9%	37,000	$ 2,181	$ 1,007	$ 1,796	2011
Douglas County PUD:						
Wells Project	3.5%	30,000	1,891	795	4,506	2018
Grant County PUD:						
Priest Rapids Project	3.3%	55,000	9,534	882	10,064	2055
Wanapum Project	8.2%	75,000	4,430	2,949	18,526	2055
Totals		197,000	$ 18,036	$ 5,633	$ 34,892	

(1) The annual costs will change in proportion to the percentage of output allocated to Avista Utilities in a particular year. Amounts represent the operating costs for the year 2007. Debt service costs are included in annual costs.

The estimated aggregate amounts of required minimum payments (Avista Utilities' share of existing debt service costs) under these PUD contracts are as follows (dollars in thousands):

	2008	2009	2010	2011	2012	Thereafter	Total
Minimum payments	$ 4,531	$ 4,554	$ 3,280	$ 3,210	$ 2,742	$ 41,265	$ 59,582

In addition, Avista Utilities will be required to pay its proportionate share of the variable operating expenses of these projects.

Avista Energy's contractual commitments to purchase energy commodities as well as commitments related to transmission, transportation and other energy-related contracts in future periods are as follows (dollars in thousands):

	2008	2009	2010	2011	2012	Thereafter	Total
Energy purchase contracts	$ 21,700	$ 21,700	$ 26,728	$ 26,728	$ 26,530	$ 316,025	$ 439,411

These contractual commitments of Avista Energy are primarily related to the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of this agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010 through 2026, the rights and obligations of the power purchase agreement for the Lancaster Plant are contracted to Avista Energy. The Company expects that these rights and obligations will be transferred to Avista Utilities, subject to future regulatory approval.

NOTE 14. SHORT-TERM BORROWINGS

The Company has a committed line of credit agreement with various banks in the total amount of $320.0 million with an expiration date of April 5, 2011. Under the credit agreement, the Company can request the issuance of up to $320.0 million in letters of credit. Total letters of credit outstanding were $34.8 million as of December 31, 2007 and $77.1 million as of December 31, 2006. The committed line of credit is secured by $320.0 million of non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions, including a covenant requiring the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Utilities for the preceding twelve-month period at the end of any fiscal quarter to be greater than 1.6 to 1. As of December 31, 2007, the Company was in compliance with this covenant with a ratio of 2.70 to 1. The committed line of credit agreement also has a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 70 percent at the end of any fiscal quarter. As of December 31, 2007, the Company was in compliance with this covenant with a ratio of 53.8 percent. If the proposed change in organization becomes effective, the committed line of credit will remain at Avista Corp.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under the Company's revolving committed lines of credit were as follows as of and for the years ended December 31 (dollars in thousands):

	2007	2006	2005
Balance outstanding at end of period	$ —	$ 4,000	$ 63,000
Maximum balance outstanding during the period	48,000	77,000	167,000
Average balance outstanding during the period	6,833	16,740	61,181
Average interest rate during the period	7.91%	6.07%	4.45%
Average interest rate at end of period	— %	8.25%	5.48%

NOTE 15. LONG-TERM DEBT

The following details the interest rate and maturity dates of long-term debt outstanding as of December 31 (dollars in thousands):

Maturity Year	Description	Interest Rate	2007	2006
2007	Secured Medium-Term Notes	5.99%	$ —	$ 13,850
2008	Secured Medium-Term Notes	6.06%-6.95%	45,000	45,000
2010	Secured Medium-Term Notes	6.67%-8.02%	35,000	35,000
2012	Secured Medium-Term Notes	7.37%	7,000	7,000
2013	First Mortgage Bonds	6.13%	45,000	45,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes (1)	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (2)	5.00%	66,700	66,700
2034	Secured Pollution Control Bonds (2)	5.13%	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
	Total secured long-term debt		666,700	680,550
2007	Unsecured Medium-Term Notes	7.90%-7.94%	—	12,000
2008	Unsecured Senior Notes	9.75%	272,860	272,860
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Total unsecured long-term debt		276,960	288,960
	Other long-term debt and capital leases		5,169	7,364
	Interest rate swaps		1,083	1,037
	Unamortized debt discount		(1,079)	(1,452)
	Total		948,833	976,459
	Current portion of long-term debt		(427,344)	(26,605)
	Total long-term debt		$ 521,489	$ 949,854

(1) These Secured Medium-Term Notes with a maturity date of June 2028 are puttable at the option of the security holders in June 2008. These notes are included in the current portion of long-term debt.

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NOTE 17. INTEREST RATE SWAP AGREEMENTS

Avista Corp. enters into forward-starting interest rate swap agreements to manage the risk associated with changes in interest rates and the impact on future interest payments. These interest rate swap agreements relate to the interest payments for the anticipated issuances of debt. These interest rate swap agreements are considered hedges against fluctuations in future cash flows associated with changes in interest rates in accordance with SFAS No. 133.

In 2005, the Company cash settled an interest rate swap and received $4.4 million. In December 2006, Avista Corp. cash settled an interest rate swap agreement and paid $3.7 million. These settlements were deferred as regulatory items (part of long-term debt) and will be amortized over the remaining terms of the interest rate swap agreements (forecasted interest payments) in accordance with regulatory accounting practices.

Under the terms of the two outstanding interest rate swap agreements (totaling $125.0 million) as of December 31, 2007, the value of the interest rate swaps is determined based upon Avista Corp. paying a fixed rate and receiving a variable rate based on LIBOR for a term of ten years beginning in 2008. As of December 31, 2007, Avista Corp. had a long-term derivative liability of $10.5 million and a net unrealized loss of $6.8 million recorded as accumulated other comprehensive loss on the Consolidated Balance Sheets. The interest rate swap agreements provide for mandatory cash settlement of these contracts in 2009. The amount included in accumulated other comprehensive income or loss at the cash settlement date will be reclassified to a regulatory asset or liability (part of long-term debt) in accordance with regulatory accounting practices under SFAS No. 71. This regulatory asset or liability will be amortized as a component of interest expense over the life of the forecasted interest payments.

NOTE 18. LEASES

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from one to forty-five years. Rental expense under operating leases was $4.8 million in 2007, $5.4 million in 2006 and $7.2 million in 2005. Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2007 were as follows (dollars in thousands):

Year ending December 31:	2008	2009	2010	2011	2012	Thereafter	Total
Minimum payments required	$ 4,160	$ 3,922	$ 1,685	$ 201	$ 117	$ 2,798	$ 12,883

NOTE 19. GUARANTEES

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount with respect to, the Preferred Trust Securities issued by its affiliates, AVA Capital Trust III and Avista Capital II, to the extent that these entities have funds available for such payments from the respective debt securities.

Avista Power, through its equity investment in Rathdrum Power, LLC (RP LLC), was a 49 percent owner of the Lancaster Plant, which commenced commercial operation in September 2001. In October 2006, Avista Power completed the sale of its investment in RP LLC for close to book value. The output from the Lancaster Plant is contracted to Avista Energy through 2026 under a power purchase agreement. Avista Corp. has guaranteed the power purchase agreement for the performance of Avista Energy. The majority of the rights and obligations of this agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010, the Company expects that these rights and obligations will be transferred to Avista Utilities, subject to future approval.

In connection with the transaction, on June 30, 2007, Avista Energy and its affiliates entered into an Indemnification Agreement with Shell Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Shell Energy each agree to provide indemnification of the other and the other's affiliates for certain events and matters described in the purchase and sale agreement entered into on April 16, 2007 and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the western energy markets in 2000 and 2001 (see Note 25), existing litigation, tax liabilities, matters with respect to storage rights at Jackson Prairie, and any potential issues associated with the power purchase agreement for the Lancaster Plant. In general, such indemnification is not required unless and until a party's claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy's obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of $30 million plus certain fees and expenses. Avista Capital granted Shell Energy a security interest in 50 percent of Avista Capital's common shares of

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AVISTA CORPORATION

NOTE 28. DISPOSITION OF SOUTH LAKE TAHOE PROPERTIES

In April 2005, Avista Corp. completed the sale of its South Lake Tahoe, California natural gas properties to Southwest Gas Corporation as part of Avista Utilities' strategy to focus on its business in the northwestern United States. This was the Company's only regulated utility operation in California. The cash proceeds received during 2005 were approximately $16.6 million. The total pre-tax gain for 2005 was $4.1 million related to the Company's disposition of its South Lake Tahoe natural gas properties.

NOTE 29. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. Avista Utilities' business is managed based on the total regulated utility operation. The Energy Marketing and Resource Management business segment primarily consisted of electricity and natural gas marketing, trading and resource management, including optimization of energy assets owned by other entities and derivative commodity instruments such as futures, options, swaps and other contractual arrangements. On June 30, 2007, Avista Energy and Avista Energy Canada completed the sale of substantially all of their contracts and ongoing operations. This transaction effectively ends the majority of the operations of the Energy Marketing and Resource Management business segment. This segment still owns natural gas storage facilities and has operating revenues and resource costs related to the power purchase agreement for the Lancaster Plant. See Note 3 for further information. Advantage IQ is a provider of facility information and cost management services for multi-site customers throughout North America. The Other category, which is not a reportable segment, includes other investments and operations of various subsidiaries as well as certain other operations of Avista Capital. The following table presents information for each of the Company's business segments (dollars in thousands):

	Avista Utilities	Energy Marketing And Resource Management	Advantage IQ	Other	Total Non-Utility	Intersegment Eliminations (1)	Total
For the year ended December 31, 2007:							
Operating revenues	$ 1,288,363	$ 61,541	$ 47,255	$ 20,598	$ 129,394	$ —	$ 1,417,757
Resource costs	780,998	68,676	—	—	68,676	—	849,674
Gross margin	507,365	(7,135)	—	—	(7,135)	—	500,230
Other operating expenses	198,778	14,683	33,841	19,259	67,783	—	266,561
Depreciation and amortization	86,091	548	2,402	1,609	4,559	—	90,650
Income (loss) from operations	150,053	(22,366)	11,012	(270)	(11,624)	—	138,429
Interest expense (2)	86,389	173	194	638	1,005	(954)	86,440
Income taxes	26,663	(5,880)	3,942	(391)	(2,329)	—	24,334
Net income (loss)	43,822	(11,877)	6,651	(121)	(5,347)	—	38,475
Capital expenditures	205,811	318	2,323	639	3,280	—	209,091
For the year ended December 31, 2006:							
Operating revenues	$ 1,267,938	$ 177,551	$ 39,636	$ 21,186	$ 238,373	$ —	$ 1,506,311
Resource costs	751,646	144,137	—	—	144,137	—	895,783
Gross margin	516,292	33,414	—	—	33,414	—	549,706
Other operating expenses	187,457	19,198	27,069	20,279	66,546	—	254,003
Depreciation and amortization	81,904	977	2,088	2,114	5,179	—	87,083
Income (loss) from operations	177,049	13,239	10,479	(1,207)	22,511	—	199,560
Interest expense (2)	95,521	199	609	1,769	2,577	(1,931)	96,167
Income taxes	33,127	6,595	3,616	(1,352)	8,859	—	41,986
Net income (loss)	57,794	11,567	6,255	(2,675)	15,147	—	72,941
Capital expenditures	161,266	1,042	2,627	150	3,819	—	165,085
For the year ended December 31, 2005:							
Operating revenues	$ 1,161,317	$ 167,439	31,748	$ 18,532	$ 217,719	$ (19,429)	$ 1,359,607
Resource costs	669,596	165,423	—	—	165,423	(19,429)	815,590
Gross margin	491,721	2,016	—	—	2,016	—	493,737
Other operating expenses	181,755	18,795	22,738	18,120	59,653	—	241,408
Depreciation and amortization	80,914	1,488	2,037	2,472	5,997	—	86,911
Income (loss) from operations	165,101	(18,267)	6,973	(2,060)	(13,354)	—	151,747
Interest expense (2)	91,847	395	912	1,694	3,001	(2,134)	92,714
Income taxes	29,870	(4,981)	2,147	(1,272)	(4,106)	—	25,764
Net income (loss)	52,299	(8,621)	3,922	(2,612)	(7,311)	—	44,988
Capital expenditures	215,341	1,573	1,106	1,365	4,044	—	219,385
Total Assets:							
As of December 31, 2007	$ 3,009,499	$ 30,690	$ 108,929	$ 40,679	$ 180,298	$ —	$ 3,189,797
As of December 31, 2006	2,895,883	1,017,203	100,431	42,991	1,160,625	$ —	4,056,508

(1) Intersegment eliminations reported as operating revenues and resource costs represent the transactions between Avista Utilities and Avista Energy for energy commodities and services, primarily natural gas purchased by Avista Utilities under the Agency Agreement. Intersegment eliminations reported as interest expense represent intercompany interest.

(2) Including interest expense to affiliated trusts.

2007 Electric Integrated Resource Plan

August 31, 2007

www.avistautilities.com

AVISTA®

PHOTO CREDITS

- Avista's investment in transmission infrastructure crosses the wheat fields of Washington state's Palouse region. Photo by Hugh Imhof, Avista.
- Three key components of Avista's renewable energy and DSM plans include the Noxon Rapids Hydro Facility on the Clark Fork River in Montana, education about energy efficient compact flourescent bulbs, and including power generated at the Stateline Wind Farm on the Southeast border of Washington and Oregon.

SPECIAL THANKS TO OUR TALENTED VENDORS FROM THE SPOKANE AREA WHO PRODUCED THIS IRP:

Ross Printing Company

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SAFE HARBOR STATEMENT

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's operations, results of operations and financial condition, and could cause actual results to differ materially from those anticipated.

For a further discussion of these factors and other important factors, please refer to our reports filed with the Securities and Exchange Commission which are available on our website at www.avistacorp.com. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events.

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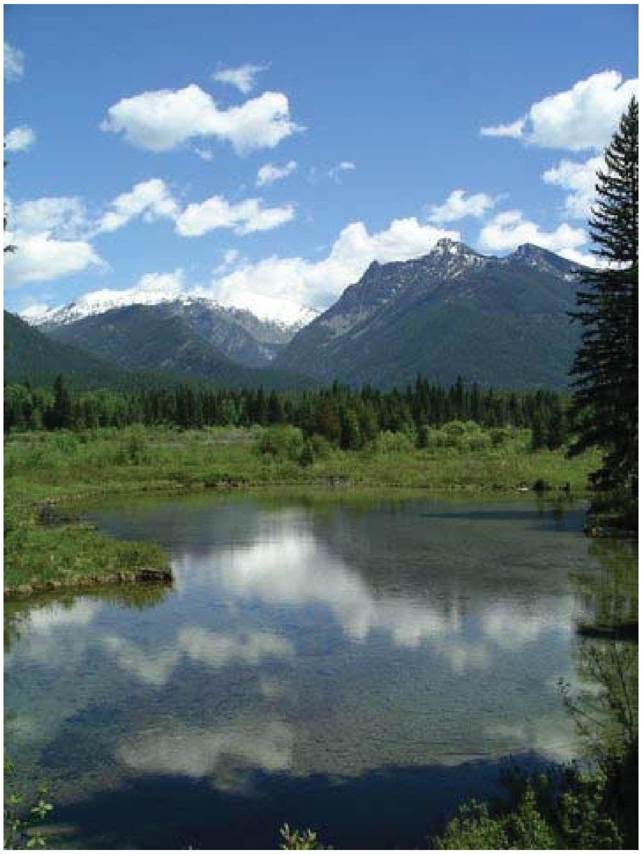
LIST OF ACRONYMS AND KEY TERMS

AARG	Annual Average Rate of Growth
AVA	Avista
aMW	Average Megawatts
BPA	Bonneville Power Administration
CCCT	Combined-Cycle Combustion Turbine
CFL	Compact Fluorescent Lamp
CO_2	Carbon Dioxide
CSA	Climate Stewardship Act (also known as the McCain-Lieberman Bill)
CVR	Controlled Voltage Reduction
Dth	decatherm
EF	Efficiency
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
GE	The General Electric Company
GHG	Greenhouse Gas
GWh	Gigawatt-hour
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning (HVAC)
IDP	Idaho Power Company
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
IS	Information Systems
kV	kilo-volt
kW	kilowatt
kWh	kilowatt-hour
LIRAP	Low Income Rate Assistance Program
LP	Linear Programming
Mmbtu	Million British Thermal Units, 1 mmbtu = 1 dth of Natural Gas
MW	megawatt
MWh	megawatt-hour
NCEP	National Commission for Energy Policy
NEB	Non-Energy Benefits
Nominal	Discounting Method that Includes Inflation
NPCC	Northwest Power and Conservation Council (formerly Northwest Power Planning Council)
NPV	Net Present Value
NWPP	Northwest Power Pool
O&M	Operations and Maintenance
OASIS	Open Access Same-Time Information System
OSU	Oregon State University
PC	Personal Computer
PGE	Portland General Electric
PRS	Preferred Resource Strategy
PRiSM	Preferred Resource Strategy Line Programming Model
psig	Pounds Per Square Inch Gauge
PTC	Production Tax Credit
PUD	Public Utility District
PURPA	Public Utility Regulatory Policies Act of 1978
Real	Discounting Method that Excludes Inflation
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
SCCT	Simple-Cycle Combustion Turbine
TAC	Technical Advisory Committee
TIG	Transmission Improvements Group
TRC	Total Resource Cost
Triple E	External Energy Efficiency Board
VFD	Variable Frequency Drive
WECC	Western Electricity Coordinating Council
WNP-3	Washington Public Power Supply System (WPPSS, now Energy Northwest) – Washington Nuclear Plant No. 3

2007 IRP KEY MESSAGES

- Resource deficits start in 2014 with loads exceeding resource capability by 49 MW. Deficits are driven by electricity sales growth averaging 2.3 percent over the next decade.
- The 2007 Preferred Resource Strategy (PRS) differs substantially from the 2005 PRS in three main areas: the removal of coal as a resource, the challenge of acquiring renewables and the need for natural gas-fired plants.
- The PRS includes 350 MW of natural gas-fired plants, 300 MW of wind, 87 MW of conservation, 38 MW of hydro plant upgrades and 34 MW of other renewables by 2017.
- The coal-fired generation forecast in previous plans is replaced entirely with natural gas-fired resources.
- Conservation acquisition is 25 percent higher than in the 2005 plan and 85 percent higher than the 2003 IRP. The company is implementing an enterprise-wide conservation and energy efficiency initiative called the "Heritage Project." It builds on the company's long-time commitment to energy conservation and efficiency, introducing new products and services to increase customers' energy savings.
- Fewer renewables meet our planned requirements due to tightening market conditions; renewables legislation in Washington and Oregon has artificially increased and accelerated the demand for these resources and therefore increased their costs. For example, wind generation costs have increased more than 50 percent since the 2005 IRP.
- Avista supports national climate change legislation and is actively participating to ensure cost-effective solutions for our customers.
- Avista has one of the smallest carbon footprints in the U.S. because of its renewable energy resources. According to a Natural Resources Defense Council study, only seven other major utilities have a smaller footprint.
- Avista's high percentage of existing renewable hydro resources, combined with a lack of available cost-effective renewable resource options, means we must continue to acquire carbon-emitting generation to meet future load growth. This increases our total carbon footprint, but our emissions per MWh of generation fall over time.
- The enactment of new laws imposing emission performance standards on fossil fueled generation resources acquired by electric utilities in Washington, Oregon and California narrows our cost-effective options, at least in the short term, to natural gas-fired generation.
- The PRS strikes a reasonable balance between keeping average costs and variation in year-to-year costs low.
- Fixing gas prices does not lower absolute cost, but it does limit price volatility.
- The power purchase contract for the Lancaster Generating Plant, previously held by Avista Energy and transferred to Coral Energy in 2007, will be available to Avista beginning in 2010. This will provide approximately 275 MW of natural gas-fired generation and will be a good resource to serve customer load.
- Action items being developed for the 2009 IRP include renewable energy and emissions, enhancements to modeling systems, transmission modeling and research, and conservation.
- The 2007 IRP was substantially complete when the company announced the availability of the Lancaster gas-fired plant to the utility. The Preferred Resource Strategy, as detailed above, includes 350 MW of natural gas-fired generation over its first 10 years. The Lancaster plant is assumed to replace a significant portion of this component. As the IRP was not re-run due to the Lancaster addition, in some places within the 2007 IRP our resource deficiencies and tabulations are shown with and without the Lancaster plant.

EXECUTIVE SUMMARY


Bull River Valley, Montana

Avista's 2007 Integrated Resource Plan (IRP) will guide utility resource acquisitions over the next two years and beyond. Besides providing a snapshot of its current resources and loads, the IRP shows where our resource portfolio is heading through the Preferred Resource Strategy (PRS). The PRS is made up of renewable resources, conservation, efficiency upgrades at existing facilities and new gas-fired generation. The most significant change from the 2005 IRP is the exclusion of coal-fired generation due to changing economics and recent legislation effectively barring its use.

Conservation acquisition is forecast to rise approximately 25 percent over the 2005 IRP level and by more than 85 percent from the 2003 IRP.

The IRP balances low cost, reliable service and reasonable future rate volatility. Avista's management and stakeholders from the Technical Advisory Committee (TAC) play a key role in directing the IRP process. TAC members include customers, Commission Staff, consumer advocates, academics, utility peers, government agencies and interested internal parties. The TAC provides significant input on modeling, planning assumptions and the general direction of the planning process.

RESOURCE NEEDS[1]

Plant upgrades and conservation acquisition are inadequate to meet all future load growth. Annual energy deficits begin in 2011, with loads exceeding resource capabilities by 83 aMW. Energy deficits rise to 272 aMW in 2017 and to 513 aMW in 2027. The company will be short 146 MW of capacity in 2011. In 2017 and 2027, capacity deficits rise to 300 MW and 835 MW, respectively. Table 1 presents the company's net position forecast during the first 10 years of the study.

Increasing deficits are a result of 2.3 percent energy and capacity load growth through 2017. Expirations of certain long-term contracts also add to the deficiencies. Figures 1 and 2 provide graphical presentations of Avista's load and resource balances. The annual forecasted load is the summation of our peak forecast plus planning and operating reserve obligations.

Table 1: Net Position Forecast

Net Position	2008	2009	2010	2011	2012	2015	2017
Energy (aMW)	121	79	33	-83	-170	-228	-272
Capacity (MW)	148	94	5	-146	-251	-357	-300

[1] Energy and Capacity positions exclude the acquisition of Lancaster. The impact of Lancaster on the company's L&R position is detailed later in this chapter.

Figure 1: Load Resource Balance—Capacity (MW)

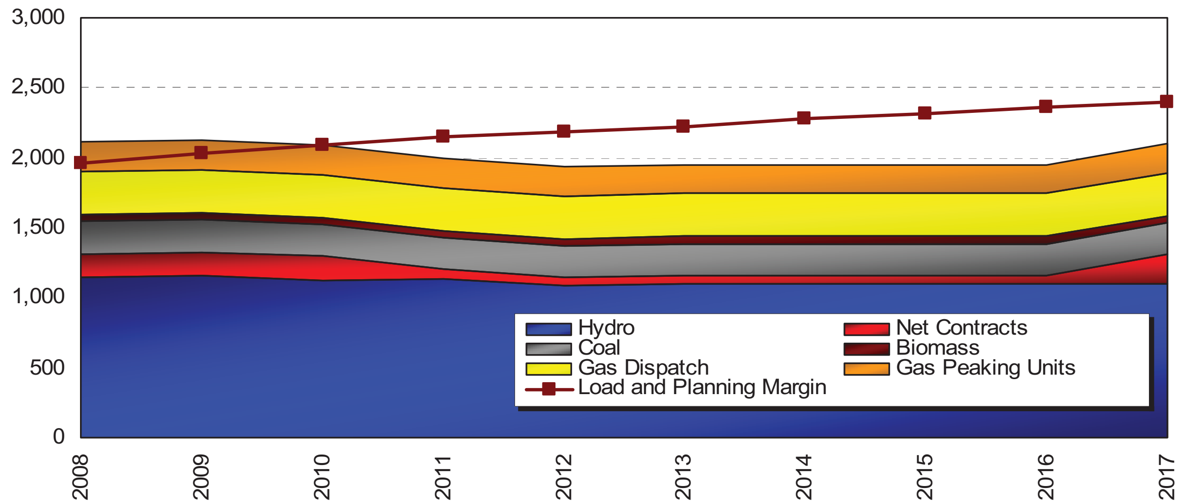
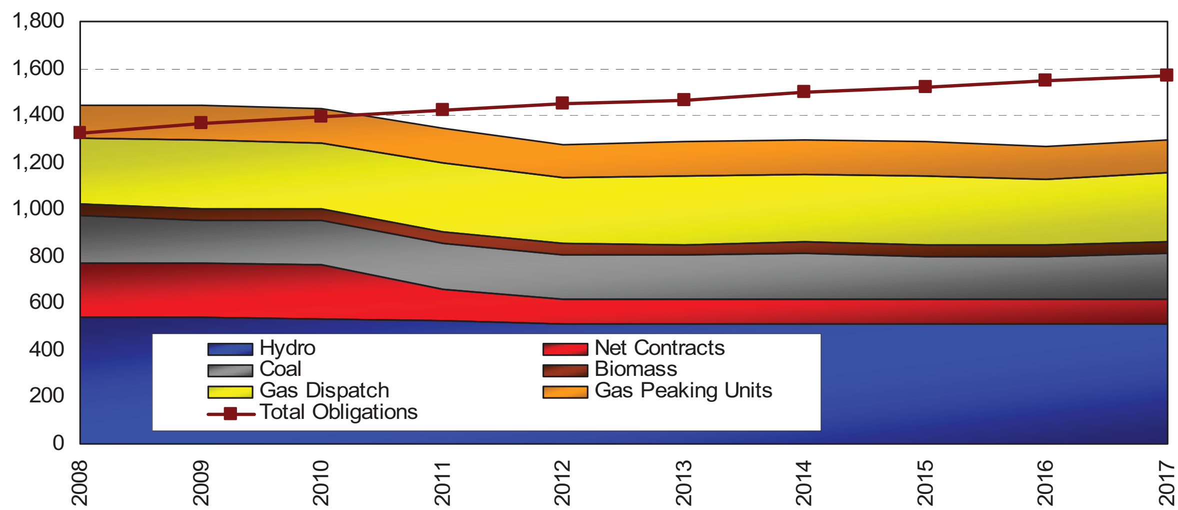


Figure 2: Load Resource Balance—Energy (aMW)



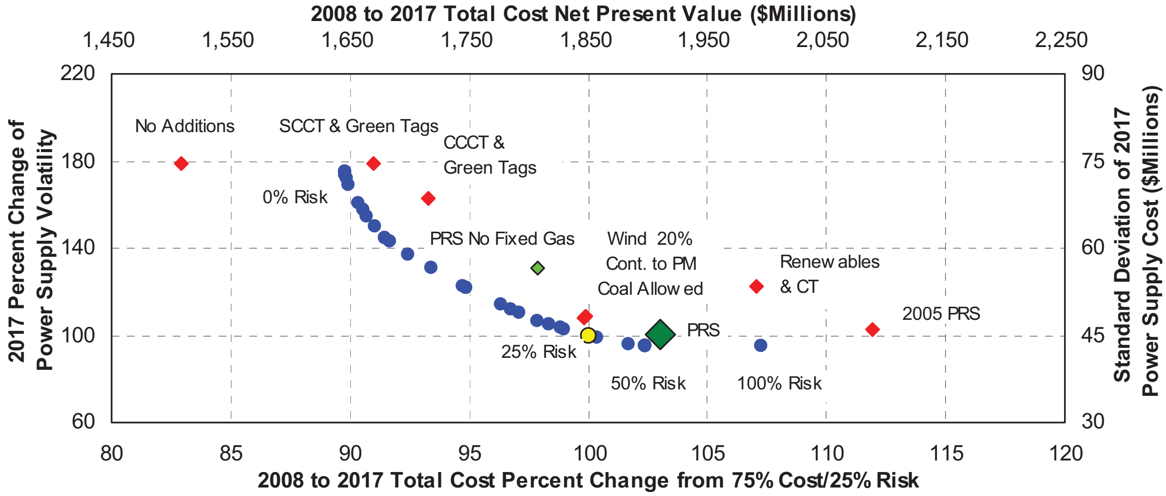
MODELING AND RESULTS

The company used a multi-step approach to develop its Preferred Resource Strategy. The process began by identifying potential new resources to serve future demand across the Western United States. A Western Interconnect-wide study was performed to understand the impact of regional markets. We believe that the additional efforts to develop this study were necessary given the significant impact other regions can have on the Northwest electricity marketplace. Existing resources were combined with the present transmission grid to simulate hourly operations from 2008 through 2027.

Cost-effective new resources and transmission were added to meet growing loads. Monte Carlo-style analysis varied hydro, wind, load and gas price data over 300 iterations of potential future conditions. The simulation results were used to estimate the Mid-Columbia electricity market. The iterations collectively formed the Base Case.

Estimated market prices were used to analyze potential conservation initiatives and available supply-side resources to meet forecasted company requirements. Each new resource option was valued against the Mid-

Figure 3: Efficient Frontier and Traditional Resource Portfolios



Columbia market to identify the future value of each asset to the company, as well as its inherent risk (e.g., year-to-year volatility). Future market values and risk were compared with the capital and fixed operation and maintenance (O&M) costs that would be incurred. Avista's Preferred Resource Strategy Linear Programming Model (PRiSM) assisted in selecting the PRS. Its selection was based on forecasted energy and capacity needs, resource values and limiting power supply expense variability.

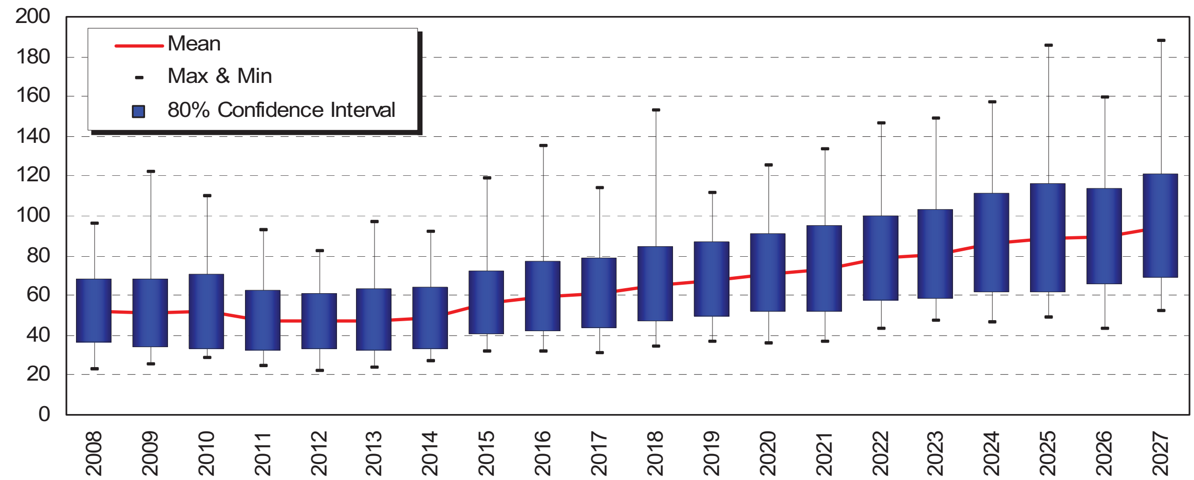
Futures and scenarios test the PRS under alternative conditions beyond the Base Case and illustrate how certain resource mixes perform in alternative market conditions. Futures are stochastic studies using a Monte Carlo approach to quantitatively assess risk around an expected mean outcome.[3] This time-intensive and multi-variable approach is the most robust method used for risk assessment. Four futures were modeled for the 2007 IRP: Base Case, Volatile Gas, Unconstrained Carbon and a High Carbon Charges.

A scenario is a deterministic study that changes a significant underlying assumption to assess the impact of that change. Scenario results are easier to understand and require less analytical effort than futures, but they do not quantitatively assess the variability or risk around the expected outcome. Seven scenarios were modeled for the 2007 IRP, including high and low natural gas prices, varying regional load growth and a scenario in which the Western Interconnect shifted all passenger automobiles to electricity instead of petroleum fuel.

Two key challenges are addressed when developing a resource portfolio—cost and risk mitigation. An efficient frontier finds the optimal level of risk given a desired level of cost and vice versa. This approach is similar to finding the optimal mix of risk and return in a personal investment portfolio. As the expected return increases, so do risks; but reducing risk decreases overall investment returns. Choosing the PRS is similar to the investor's dilemma, but the trade-off is future costs against future power supply cost variation. Figure 3 presents the changes in costs and risks from the 75/25 cost/risk position on the Efficient Frontier. It also shows alternative resource portfolios to illustrate generic resource strategies. The lower horizontal axis displays the 2008-2017 percentage change in the present value of existing and future costs. The upper horizontal axis presents actual present value dollars. The right-hand

[3] Stochastic studies use probability distributions (i.e., means and standard deviations) to forecast future variables.

Figure 4: Base Case Stochastic Mid-Columbia Prices ($/MWh)



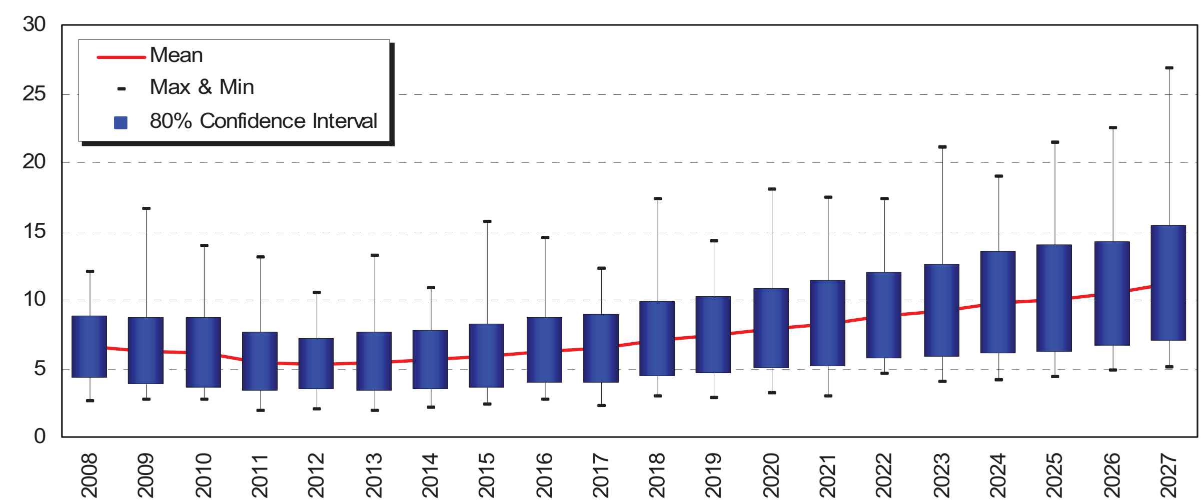
vertical axis shows power supply volatility as a single standard deviation of the average power supply expense. The left-hand vertical axis shows the percent change in 2017 power supply volatility. Both axes are shown as percentages of the 75/25 cost/risk mix to illustrate the relative impacts of moving between resource strategies.

The blue dots represent the Efficient Frontier of various resource portfolios developed by PRiSM to meet future resource requirements. The PRS is not on the Efficient Frontier curve because resource lumpiness is assumed in the first 10 years of the study.[4] The PRS is based on the 25/75 risk/cost portfolio weighting.

ELECTRICITY AND NATURAL GAS MARKET FORECASTS

Figure 4 represents Avista's Base Case electricity price forecast and the range of prices across its Monte Carlo runs. The selected resource portfolio must provide a hedge against such price movement.

Figure 5: Annual Average Sumas Natural Gas Price Results from 300 Iterations ($/Dth)



[4] Resources enter a utility portfolio in blocks that do not perfectly match load in a given year. For example, it is difficult to cost-effectively acquire a 35 MW share of a CCCT plant. Instead, resources enter the utility portfolio in larger blocks and manage deficiencies for a period of years.

Electricity prices are highly correlated with natural gas prices. Base Case natural gas prices across the Monte Carlo simulations at the Sumas trading hub are shown in Figure 5. Natural gas volatility is similar to electricity price volatility in Figure 4.

DEMAND SIDE MANAGEMENT ACQUISITION

Figure 6 shows how conservation and energy efficiency have decreased Avista's energy requirements by nearly 100 aMW since programs began in the late 1970s.[5] With additional funding recommended by the IRP and through the Heritage Project, the company expects accumulated conservation to lower its load growth 87 aMW by 2017. The 2007 IRP conservation acquisition schedule is approximately 25 percent higher than the 2005 IRP and 85 percent higher than the 2003 IRP.

PREFERRED RESOURCE STRATEGY

The Preferred Resource Strategy is developed after careful consideration of the information gathered

Figure 6: Cumulative Efficiency Acquisitions

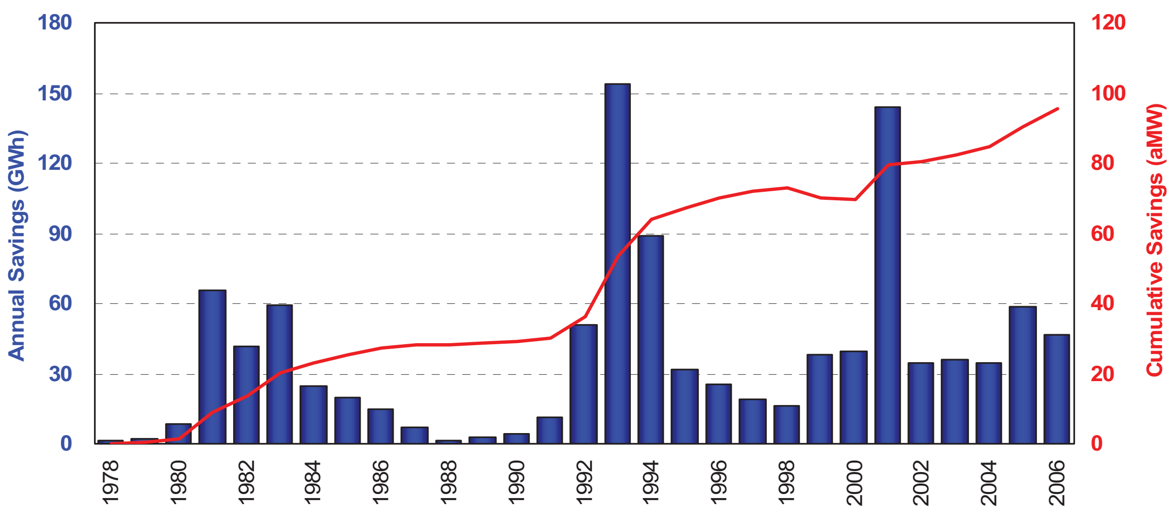
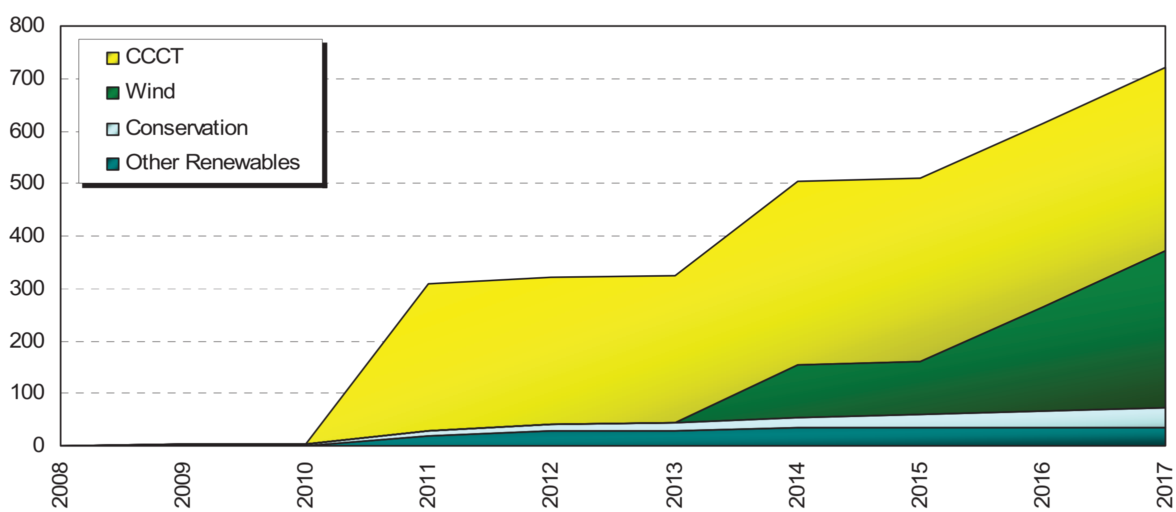


Figure 7: The 2007 Preferred Resource Strategy (aMW)



[5] Actual energy savings total 124 aMW; however, due to expected degradation of historical measures (18-year average measure life), cumulative savings are lower.

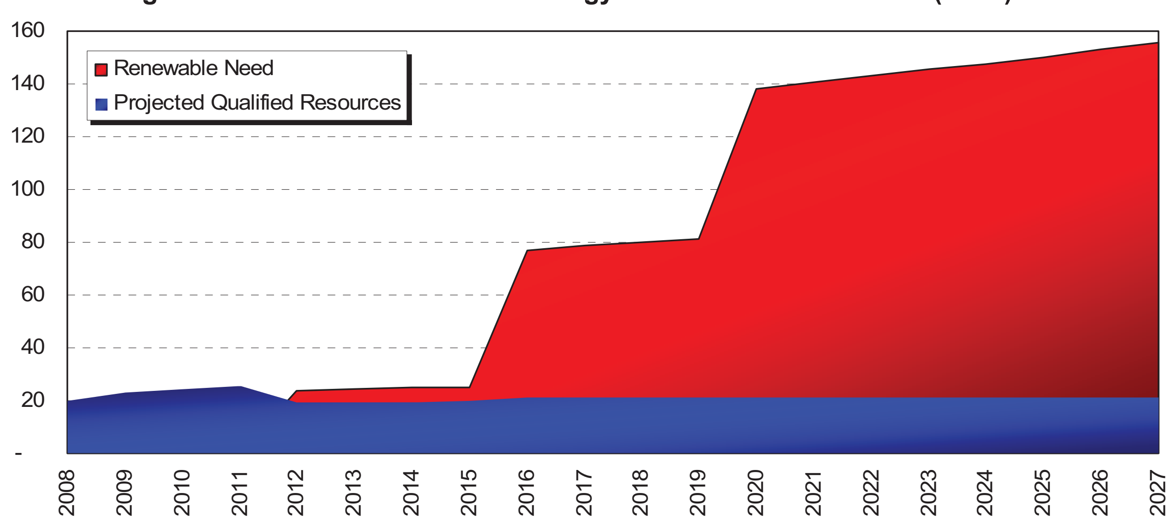
Table 2: 2007 Preferred Resource Strategy Selections (Nameplate MW)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
CCCT	0	0	0	280	280	280	350	350	350	350
Coal	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	100	100	200	300
Other Renewables	0	0	0	20	30	30	35	35	35	35
Conservation	6	13	20	27	36	46	56	66	76	87
Total	6	13	20	327	346	356	541	551	661	772

through the IRP process. The PRS is reviewed by management and the Technical Advisory Committee. The 2007 plan relies on conservation, system efficiency upgrades, renewable resources and gas-fired combined-cycle combustion turbines (CCCTs). Figure 7 illustrates the company's Preferred Resource Strategy for the 2007 IRP.

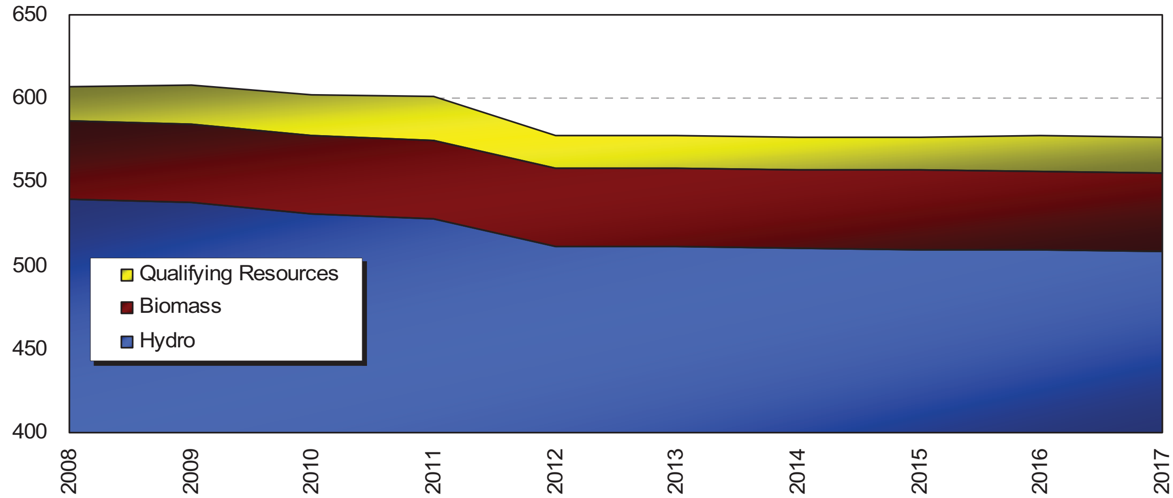
The specific resources contained within the PRS, in nameplate capability, are shown in Table 2.
The PRS requires between $1.0 and $1.5 billion in new investments over the next 10 years.[6] The 2007 IRP contains lower amounts of wind and other renewable resources than were included in the 2005 IRP. Conditions have changed since the 2005 IRP which have and will impact the cost of renewable resources relative to traditional thermal alternatives. Recent legislation promoting renewable resources in Washington and throughout the West have reduced the amount of cost-effective renewable resources available to Avista by increasing and accelerating demand in the short run. Wind generation costs have increased by more than 100 percent over the past six years and by more than 50 percent since the 2005 IRP. Renewable resources are being acquired to meet the Washington Energy Independence Act, Initiative 937 (I-937), passed in November 2006. This legislation requires larger utilities in Washington to serve 15 percent of retail load with renewables by 2020; intermediate targets are 3 percent in 2012 and 9 percent in 2016. Under I-937, Avista must acquire renewable resources regardless of physical resource balance. We forecast that by 2017 approximately 90 aMW of I-937-qualifying resources will serve customers loads, as shown in Figure 8.

Figure 8: Amount of Renewable Energy Forecasted to Meet RPS (aMW)



[6] The range reflects the possibility that the company might need to invest approximately $0.5 billion to fix the long-term price of its natural gas (e.g., purchase of coal gasifier to create pipeline-quality natural gas).

Figure 9: I-937 Qualifying and Non-Qualifying Avista Renewables (aMW)



Avista currently serves approximately one-half of customer requirements with renewable resources (hydro, wind and biomass), and these resources will meet 40 percent of our load obligations in 2017. Unfortunately, only a small portion of our current renewable resource portfolio qualifies under I-937, see Figure 9.

LOWERING VOLATILITY WITH LONG-TERM FIXED PRICE GAS

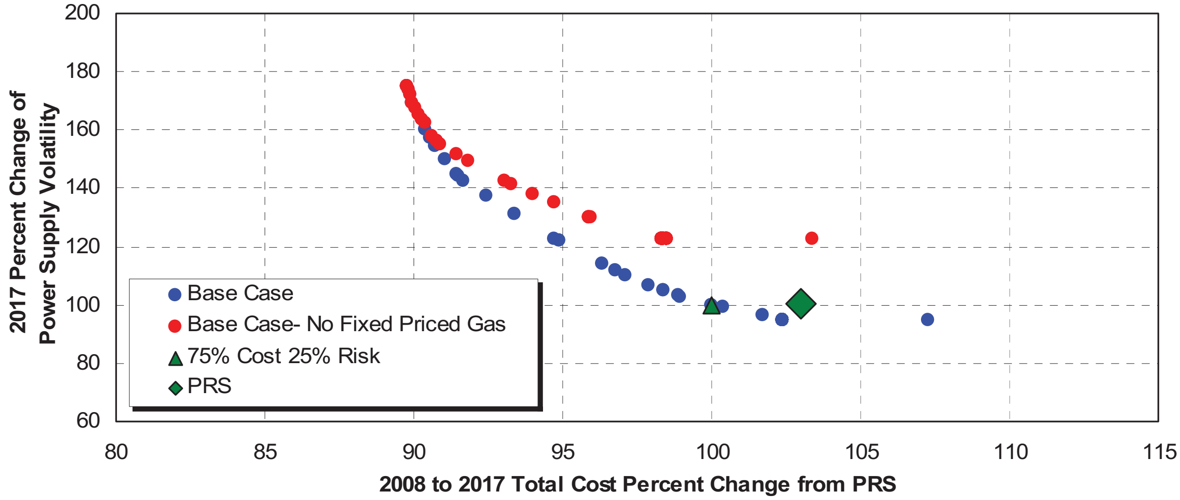
Coal-fired generation accounted for a significant portion of the Avista's PRS mix in both the 2003 and 2005 IRPs. Coal-fired plants provide a hedge against volatile electricity and natural gas prices because 60 percent or more of their costs are fixed through large capital investments. Variable operating and fuel costs at a coal plant are modest compared to gas-fired resources. A resource profile containing coal contributes to stable power supply expenses.

The cost of operating gas-fired resources, on the other hand, is highly correlated with the electricity marketplace. Natural gas prices are volatile. The fixed costs of natural gas plants are low relative to their all-in cost, approximately 20 percent, reflecting a low capital investment. Utility portfolios with large concentrations of gas-fired generation can suffer from costs that are less stable than utilities who rely on other sources of generation.

Gas-fired plants have not experienced the same rise in capital costs that coal-fired plants have. In fact, recent experience by Avista (Coyote Springs 2) and Puget Sound Energy (Goldendale) indicate that independent power producers in the Northwest marketplace are willing to sell their gas-fired plants at prices below the green field costs assumed in this plan. The enactment of new laws imposing emission performance standards on fossil-fueled generation resources acquired by electric utilities in Washington and California will narrow baseload technology options, at least in the short-term, to gas-fired generation. This restriction, coupled with regional load growth and the prospect of additional greenhouse gas regulations on fossil-fueled generation resources, particularly coal-fired generation, may ultimately increase demand for and the cost of gas-fired plants.

Locking in natural gas costs through a long-term fixed-price contract, an investment in a pipeline-quality coal gasification plant, an investment in gas fields or through other means makes a gas-fired combined cycle combustion turbine (CCCT) cost structure behave

Figure 10: Efficient Frontier With and Without Fixed Price Gas Contracts Option



financially like a coal-fired resource. Variable costs are greatly reduced and are much less volatile because a significant portion of its largest variable component—gas fuel—is not tied to the natural gas market. In both high and low gas market conditions the price paid by customers is the same. In years where natural gas prices are high, the fixed-cost contract looks very attractive financially and customers pay less than if the company relied on shorter-term purchases. On the other hand, years with low natural gas prices make the fixed-cost contract look financially unattractive compared to a short-term purchase. Over time, the long-run cost of operations with fixed-price gas should parallel the cost of operations where a gas plant is fueled with short-term gas.

The company tested the benefits of fixed price contracts with PRiSM and found that the model had a general preference for fixed price gas because of its ability to reduce risk. Even with premiums as high as 75 percent above the forecasted short-term gas price, the PRiSM model selects this resource option for a portion of the preferred portfolio. In the Base Case, where a 30 percent fixed gas price premium is modeled, risk is reduced by approximately 20 percent, as shown in Figure 10. An empirical study by Avista explains that year-on-year volatility for a hypothetical CCCT plant could have been reduced by 50 percent during the years 2002-2006 were fixed price gas used to fuel the plant.[7]

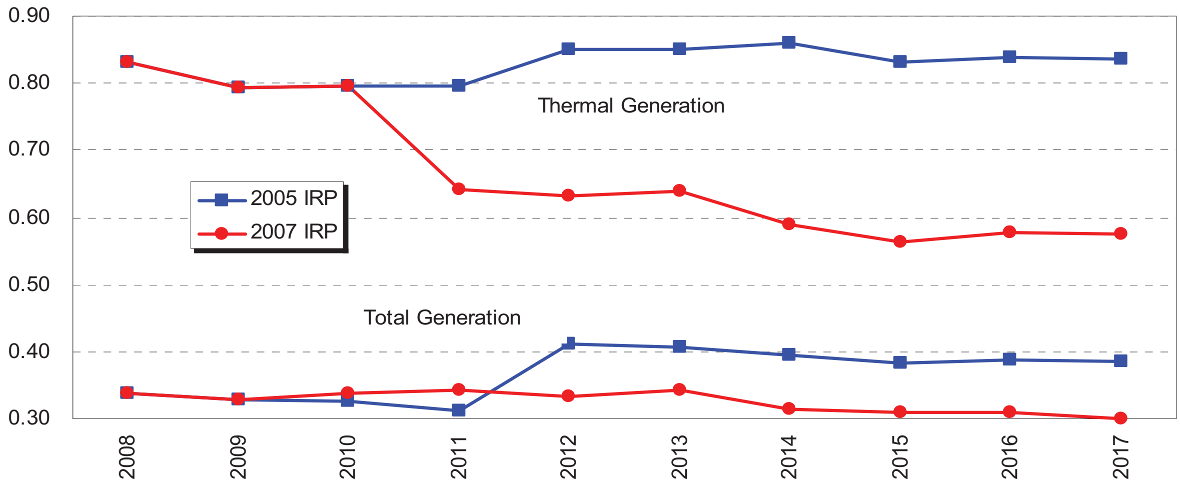
CARBON EMISSIONS

Carbon emissions are included in the Base Case for the first time in this IRP cycle. The National Commission on Energy Policy study, completed in late 2004, provided the basis for pricing carbon emissions in the Base Case.[8] To quantify potential risks inherent in a higher carbon emission cost scenario, the company looked to an Energy Information Administration study of the McCain-Lieberman Climate Stewardship Act.[9] These two cases illustrate the potential risk inherent in relying too heavily on traditional carbon-emitting technologies.

Avista has one of the smallest carbon footprints in the United States because of its existing renewable energy resources. Out of the top 100 producers of electric power in the 2006 Benchmarking Air Emissions study by the Natural Resources Defense Council, only seven other utilities have a smaller footprint. However, the

[7] A broader discussion of this study is presented in Chapter 8.
[8] See www.energycommission.org
[9] See www.eia.doe.gov

Figure 11: Carbon Footprint (Tons per MWh)



company's carbon footprint is forecast to rise over the IRP timeframe because it would be very difficult to acquire sufficient amounts of additional cost-effective renewable resources to meet all future load growth. Figure 11 forecasts Avista's carbon footprint for generation and compares it to the 2005 IRP. Our emissions footprint is approximately 25 percent lower.

LANCASTER

The company announced the sale of its energy marketing company, Avista Energy, in April 2007. It subsequently announced that Avista Energy's contract for the Lancaster Generation Facility output is available to the utility beginning in 2010. The announcement came after the company had substantially completed its IRP analysis and Preferred Resource Strategy. Given that Lancaster is the same technology and available in the same timeframe as the 280 MW gas-fired combined cycle resource identified in the PRS, the resource strategy was not updated. Instead, an alternative portfolio including Lancaster is compared to the PRS to illustrate its impacts. The Lancaster Generation Facility is a 245 MW gas-fired combined-cycle combustion turbine with an additional 30 MW of duct firing capability. It is a newer General Electric Frame 7FA that began commercial service in 2001. Avista controls plant operations under a tolling arrangement through 2026. Recently completed preliminary analysis has identified Lancaster as a potentially cost-effective resource to meet customer load requirements. The plant is located in Rathdrum, Idaho, in the center of Avista's service territory. It is significantly lower in cost than a green field plant.

LANCASTER IMPACT ON L&R BALANCES

Lancaster substantially replaces the identified gas-fired CCCT plant included in the PRS. Table 3 presents the company's net position with the inclusion of Lancaster. Figure 12 reflects Lancaster's inclusion in our loads and resources tabulation.

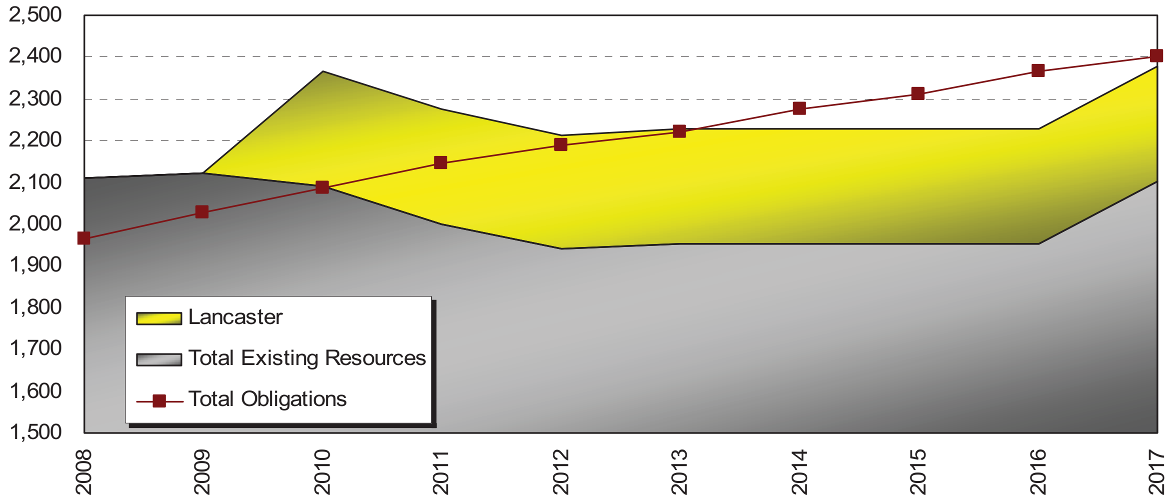
ACTION ITEMS

Avista's 2007 Action Plan outlines the activities and studies to be developed and presented in the 2009 Integrated Resource Plan. The Action Plan was developed with input from Commission Staff, Avista's management team, and the Technical Advisory

Table 3: Net Position Forecast with Lancaster

Net Position	2008	2009	2010	2011	2012	2015	2017
Energy (aMW)	121	79	288	181	79	37	-8
Capacity (MW)	148	94	280	129	24	-82	-25

Figure 12: Loads & Resources Capacity Forecast with Lancaster (MW)



Committee. The Action Plan is found in Chapter 9. Categories of action items include renewable energy and emissions, modeling enhancements, transmission modeling and research, and conservation.

1. INTRODUCTION AND STAKEHOLDER INVOLVEMENT

Avista submits a biennial Integrated Resource Plan (IRP) to the Idaho and Washington public utility commissions.[1] The 2007 IRP is Avista's 10th plan. It describes the Preferred Resource Strategy for meeting customers' future requirements while balancing cost and risk.

The company has a statutory obligation to provide reliable electric service to customers at rates, terms and conditions that are just, reasonable and sufficient. We assess resource acquisition strategies and business plans to meet resource adequacy and renewable portfolio requirements, and to optimize the value of our current resource portfolio. Avista uses the IRP as a resource evaluation tool rather than an acquisition plan. The 2007 IRP focuses on refining our processes for evaluating resource decisions, requests for proposal and other acquisition efforts.

IRP PROCESS

Avista actively seeks input from a variety of constituents including Commission Staff, customers, academics and other interested parties. The company sponsored five Technical Advisory Committee (TAC) meetings for the 2007 IRP, including a two-day meeting in August 2006. The TAC process began on February 24, 2006, and ended with a final meeting on April 25, 2007. Over 90 people were invited. Each TAC meeting covered different aspects of the 2007 IRP planning activities and solicited contributions and assessments of modeling assumptions, processes and results. The 2007 IRP marked the first time that the company provided TAC members with a draft Preferred Resource Strategy (PRS) in the middle of the IRP process. The PRS was presented at the second TAC meeting. It gave TAC participants an opportunity to understand the potential results of the IRP modeling process.

STAKEHOLDER PARTICIPATION

The IRP process provides substantial opportunities for stakeholders to participate in Avista's resource planning activities. Avista utilizes three different groups of stakeholders. The main contingent involves stakeholders with some level of expertise in utility planning, who provide input concerning the IRP studies, resource data, modeling efforts, and critical review of the modeling results. This group includes Commission Staff, planners from other utilities, academics and consultants. The second group includes parties who are involved with a critical aspect of the IRP. Examples of members of this group include environmental advocates and government agencies. The third group includes delegates from regional planning efforts, such as the Northwest Power and Conservation Council and the Western Electricity Coordinating Council.

PUBLIC PROCESS

The 2007 IRP is a publicly-developed document. All of the 2007 IRP TAC presentations, along with past IRPs and TAC presentations, are available for review at www.avistautilities.com. The entire 2007 IRP, its technical appendices, and its supporting documents can be downloaded from this location.

TECHNICAL ADVISORY COMMITTEE

Avista's Integrated Resource Plan benefits from public input and involvement. The company held six full days of TAC meetings, which were supplemented with phone and email contact, to develop this plan. Some of the topics included in the 2007 TAC series were resource options, conservation, modeling, fuel price forecasts, load forecasts, market drivers and emissions issues.

[1] Washington IRP requirements are contained in WAC 480-100-251 Least Cost Planning. Idaho IRP requirements are outlined in Case No. U-1500-165 Order No. 22299, Case No. GNR-E-93-1, Order No. 24729, and Case No. GNR-E-93-3, Order No. 25260.

Table 1.1: TAC Participants

Participant	Organization
Andy Ford	WSU
Brad Blegan	City of Spokane
Dan Pfeiffer	IPUC
Dave Van Hersett	Resource Development Associates
Hank McIntosh	WUTC
Joelle Steward	WUTC
Yohannes Mariam	WUTC
Doug Kilpatrick	WUTC
Steve Johnson	Public Counsel
Hugh Nguyen	Puget Sound Energy
Kirsten Wilson	WA State Gen Admin
Rick Sterling	IPUC
Mark Stokes	Idaho Power
Terry Morlan	NPCC
Liz Klumpp	CTED
Mike Kersh	Inland Empire Paper

The TAC mailing list includes more than 90 individuals from 42 different organizations. Avista greatly appreciates all of the time and effort expended by participants in the TAC process and we look forward to their continued involvement in future IRPs. The company would like to particularly thank the participants listed in Table 1.1 for their input and involvement.

ISSUE-SPECIFIC PUBLIC INVOLVEMENT ACTIVITIES

In addition to the TAC, Avista sponsors and participates in other collaborative processes involving public interests.

External Energy Efficiency ("Triple E") Board

Since 1995 the Triple E Board has been meeting biannually to gather and provide guidance on conservation efforts. The Triple E grew out of the DSM Issues Group, which was influential in developing the country's first distribution surcharge for conservation acquisition.

FERC Hydro Relicensing – Clark Fork River Projects

Over 50 stakeholder groups participated in the Clark Fork hydro-relicensing process beginning in 1993. This led to the first all-party settlement filed with a FERC relicensing application and eventual issuance of a 45-year Federal Energy Regulatory Commission (FERC) operating license in February 2003. The nationally recognized Living License concept was a result of this process. This collaborative process continues implementing the Living License with stakeholders participating in various protection, mitigation and enhancement measures. These measures include the purchase of over 1,100 acres of wetland and upland habitat for the bull trout, fish passage programs and improvements to 19 recreational facilities along the reservoir.

FERC Hydro Relicensing – Spokane River Projects

Our Spokane River Project license expires in August 2007. Avista's hydro relicensing process for the Spokane River Projects mimics the Clark Fork process. Approximately 100 stakeholder groups participate in this collaborative effort. Draft license applications were filed with FERC on July 28, 2005. FERC recently released a draft Environmental Impact Statement and held a public hearing in Spokane on February 8, 2007.

Low Income Rate Assistance Program (LIRAP)

LIRAP is developed through regular meetings with four

Table 1.2: TAC Meeting Dates and Agenda Items

Meeting Date	Agenda Items
TAC 1 – February 24, 2006	• IRP Rules and Regulations • Work Plan Discussion • 2005 IRP and TAC Comments • 2007 IRP Topic Discussions: Resource Planning, Conservation, Analytical Process, and Capacity Planning
TAC 2 (Day 1) – August 31, 2006	• Review of 2005 Action Plan • IRP Modeling Overview: Emissions, Fuel Price Forecasting, Modeling Assumptions, Preliminary Transmission Costs and Paths, Resource Options and Cost Assumptions, and Futures and Scenarios • 2006 Renewables RFP • Future Resource Requirements (L&R) • Review of Futures and Scenarios Market Results • Preliminary Preferred Resource Strategy (PRS)
TAC 2 (Day 2) – September 1, 2006	• Preliminary PRS Discussion: Portfolio Selection Criteria, Futures & Scenarios, PRS Selection Model, and Results • Alternative Energy
TAC 3 – January 10, 2007	• Draft PRS Review • Fuel Price Forecast • Clean Coal Presentation • Emissions Update • Load Forecast • Conservation
TAC 4 – March 28, 2007	• Market Analysis • Conservation Program Update • Portfolio Selection Criteria • Cost of Service • Transmission Estimates • 2007 IRP Draft Outline
TAC 5 – April 25, 2007	• Presentation of the 2007 PRS • 2007 IRP Action Items

community action agencies in the company's Washington service territory. The program began in 2001 to review administrative issues and needs. Meetings are held quarterly.

REGIONAL PLANNING

The Pacific Northwest's generation and transmission system is operated in a coordinated fashion. Avista participates in the activities of many organizations' planning efforts. Information from this participation is used to supplement its integrated resource planning process. Some of the organizations that Avista participates in include:

- Western Electricity Coordinating Council
- Northwest Power and Conservation Council
- Northwest Power Pool
- Pacific Northwest Utilities Conference Committee
- ColumbiaGrid
- Northwest Transmission Assessment Committee
- Seems Steering Group – Western Interconnection
- North American Electric Reliability Council

FUTURE PUBLIC INVOLVEMENT

Avista will continue to actively solicit input from interested parties. Advice will be requested from members of the Technical Advisory Committee on a wide variety of resource planning issues. We will continue to work on diversifying TAC membership and will strive to maintain the TAC meetings as an open, public process.

2007 IRP OUTLINE

The 2007 IRP consists of eight chapters plus an executive summary and this introduction. A series of technical appendices supplement this report.

EXECUTIVE SUMMARY

This chapter summarizes the overall results and highlights key aspects of the 2007 IRP.

CHAPTER 1: INTRODUCTION AND STAKEHOLDER INVOLVEMENT

This chapter introduces the IRP and provides details concerning public participation and involvement in the integrated resource planning process.

CHAPTER 2: LOADS AND RESOURCES

The first half of this chapter covers Avista's load forecast along with relevant local economic forecasts. The last half of this chapter describes the company's owned generating resources, major contractual rights and obligations, capacity and energy tabulations, and reserve issues.

CHAPTER 3: DEMAND SIDE MANAGEMENT

This chapter provides an overview of Avista's energy efficiency programs, descriptions and analysis of efficiency measures for the IRP and the selected programs for the 2007 IRP.

CHAPTER 4: ENVIRONMENTAL ISSUES

This chapter covers emissions issues that were modeled in the 2007 IRP. The chapter focuses on modeling efforts and issues surrounding SO_x, NO_x, Hg and CO_2. State and federal emissions regulations and policies are also discussed.

CHAPTER 5: TRANSMISSION PLANNING

This chapter reviews Avista's distribution and transmission systems, as well as regional transmission planning issues. Transmission cost studies used in modeling efforts are also covered in this chapter.

CHAPTER 6: MODELING APPROACH

This chapter provides the Mid-Columbia and Western Interconnect market results for the Base Case and scenario analyses.

CHAPTER 7: MARKET MODELING RESULTS

This chapter covers the results of the Base Case and scenario analyses for the Western Interconnect and Mid-Columbia electricity market.

CHAPTER 8: PREFERRED RESOURCE STRATEGY

This chapter provides details about Avista's 2007 Preferred Resource Strategy. It compares the PRS to a variety of theoretical portfolios under stochastic and scenario based analyses.

CHAPTER 9: ACTION ITEMS

This chapter reviews the progress made on the 2005 IRP Action Items and describes the 2007 IRP Action Items.

2. LOADS AND RESOURCES

INTRODUCTION & HIGHLIGHTS

Loads and resources represent two key components of the IRP. The first half of this chapter summarizes customer and load forecasts for our service territory, including high and low forecasts, load scenarios and an overview of recent enhancements to our forecasting models and processes. The second half covers our resources, including company owned and operated resources, as well as long-term contracts.

UTILITY LOADS

ECONOMIC CONDITIONS IN THE ELECTRIC SERVICE TERRITORY

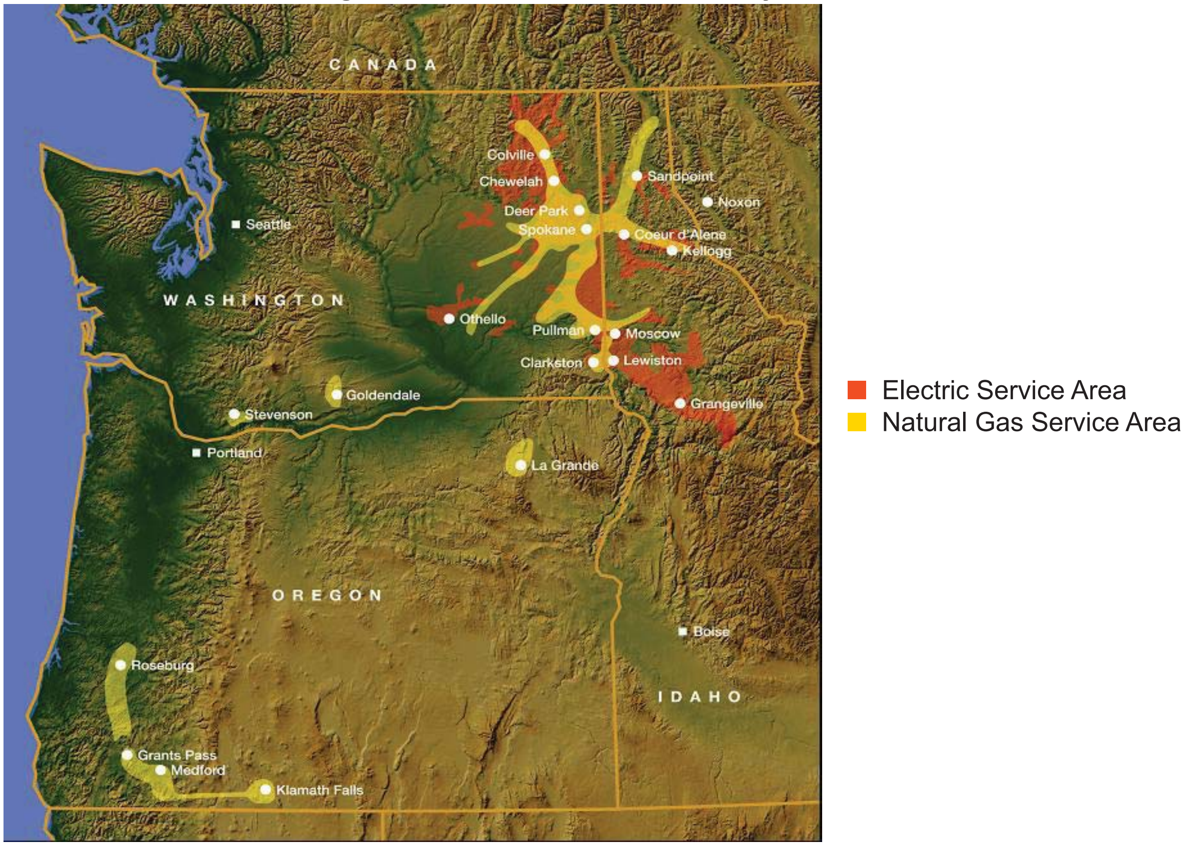
Avista serves a wide area of Eastern Washington and Northern Idaho. This area is geographically and economically diverse. Avista serves most of the urbanized and suburban areas in 24 counties. Figure 2.1 is a map of the company's electric and natural gas service territory.

Sandpoint, Idaho

CHAPTER HIGHLIGHTS

- Strong economic growth continues throughout the company's service territory.
- Historic conservation acquisitions are included in the load forecast; higher acquisition levels envisioned in this plan will be in addition to levels included in the forecast.
- Electricity sales growth averages 2.3 percent over the next 10 years (254 aMW) and 2.0 percent over the entire 20-year forecast.
- Peak loads are expected to grow at 2.4 percent over the next 10 years (400 MW) and 2.1 percent over the entire 20-year forecast.
- Avista's resource deficits begin in 2011, 2014 with the Lancaster plant.
- Capacity deficiencies drive our resource needs.

Figure 2.1: Avista's Service Territory



The economy of the Inland Northwest has transformed over the past 20 years, from natural resource-based manufacturing to diversified light manufacturing and services. Much of the mountainous area of the region is owned by the Federal government and managed by the United States Forest Service. Timber harvest reductions on public lands have closed many local sawmills. Two pulp and paper plants served by Avista have large forest land holdings, but they continue to face stiff domestic and international competition for their products.

Employment expands during expansionary times and contracts during recessions. Our service territory experienced large scale unemployment during two national recessions in the 1980s. Avista's service territory was mostly bypassed by the 1991/92 national recession, but it was not as fortunate during the 2001 recession. The effects of recessions and economic growth are best illustrated by employment for the three principal counties in the company's electric service area. Regional employment data is provided later in this chapter. Population levels often are more stable than employment levels during times of economic change; however, total population often contracts during severe economic downturns as people leave in search of job opportunities. Over the past 20 years, only in 1987 did the region experience a net loss in population. Figure 2.2 details annual population changes in Bonner, Kootenai and Spokane counties. Figure 2.3 shows total population in these three counties.

ECONOMIC, CUSTOMER, AND SALES FORECASTS

People, Jobs and Customers

Avista purchases national and county-level employment and population forecasts from Global Insight, Inc. Global Insight is an internationally recognized economic forecasting consulting firm used by various agencies in Washington and Idaho. The data encompasses the three

Figure 2.2: Population Change for Spokane, Kootenai and Bonner Counties (Thousands)

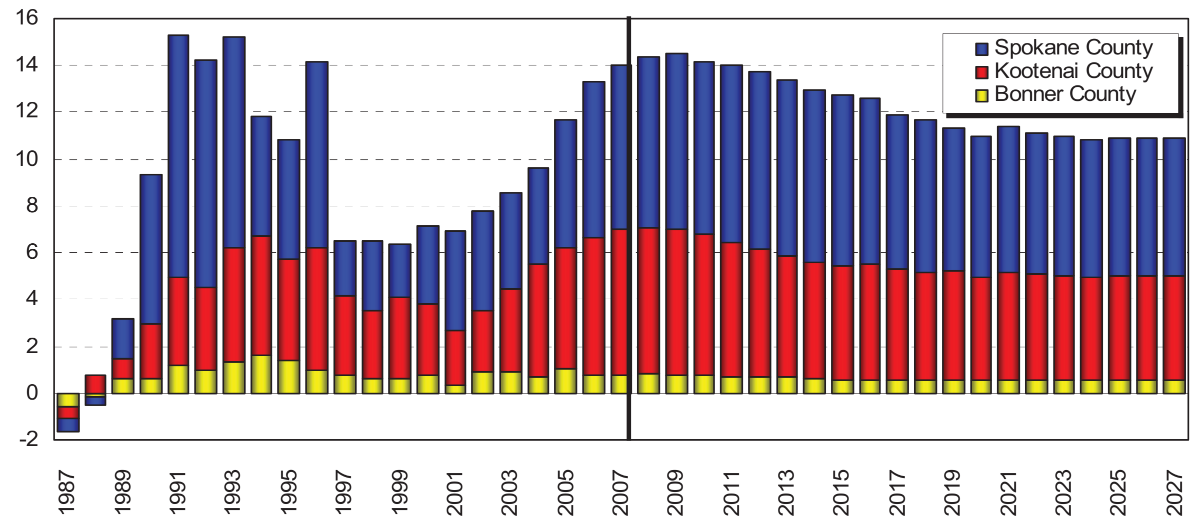


Figure 2.3: Total Population for Spokane, Kootenai and Bonner Counties (Thousands)

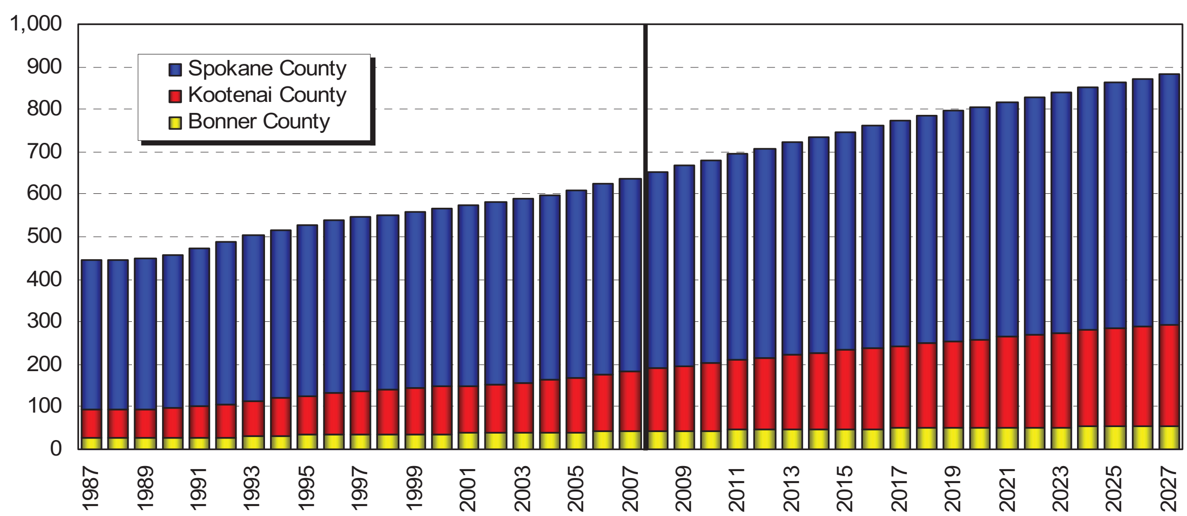


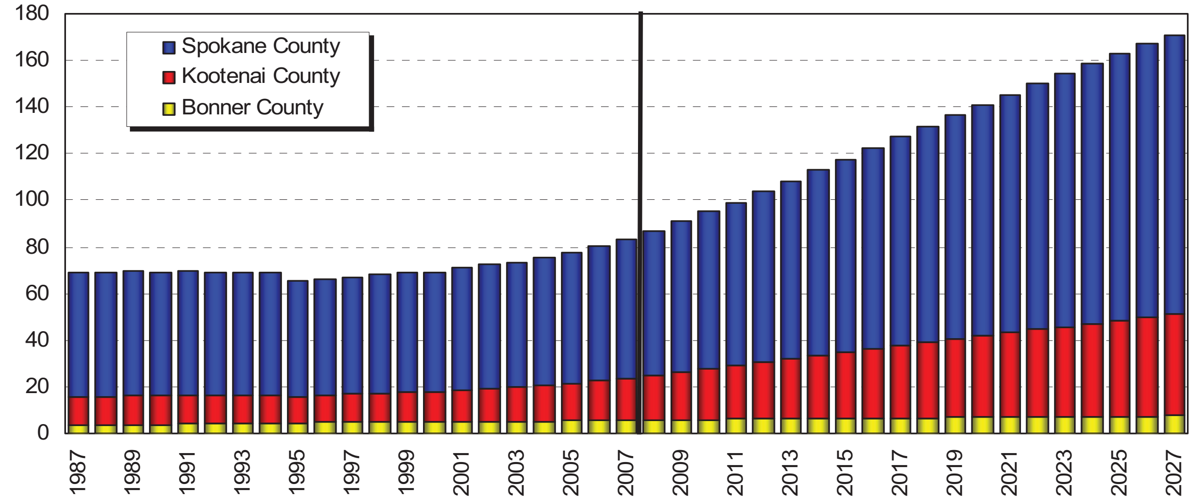
Table 2.1: Global Insights National Forecast Assumptions

Assumption	Range	Assumption	Range
Gross Domestic Product	2.5-3.5%	Housing Starts (mil.)	2.60-2.75
Consumer Price Index	2.5%-2.0%	Job Growth	0.5%-2.0%
West Texas Crude	$60-$65	Worker Productivity	2%
Treasury Bonds	5.0%-5.5%	Consumer Sentiment	90
Unemployment Rate	<5.0%		

principal counties which comprise over 80 percent of our service area economy, namely Spokane County in Washington and Kootenai and Bonner counties in Idaho. The national forecast is based on regional forecasts prepared in March 2006; county-level estimates were completed in June 2006.

The forecast and underlying assumptions used in this IRP were presented at the third Technical Advisory Committee meeting for Avista's 2007 Integrated Resource Plan on January 10, 2007. Key forecast assumptions are shown in Table 2.1.

Figure 2.4: Three-County Population Age 65 and Over (Thousands)



Looking forward, the national economy slowed after recovering from the 2001 recession, setting the stage for regional economic performance in Avista's service area in Eastern Washington and Northern Idaho. As shown in the charts above, population growth has rebounded after slow growth from 1997 to 2002. Population growth is expected to continue its recent trend through 2010.

Regional population growth is supported by the emigration of retirees, representing between 10 and 20 percent of overall population growth. Figure 2.4 presents the population history and forecasts for individuals 65 years and over in the three-county area. Between 1986 and 2006 this segment grew by compound growth rates of 2.4 percent in Bonner County, 2.0 percent in Kootenai County and 0.5 percent in Spokane County. This age group represented 13 percent of the overall population in 2006. The forecast predicts growth of 2.5 percent, 4.5 percent and 3.5 percent, respectively, pushing the overall contribution of this age group to 19 percent in 2027.

Employment growth drives population growth. Figure 2.5 shows employment trends in the prior two and future two decades.

Overall non-farm wage and salary employment over the past 20 years averaged 3.7 percent for Bonner County,

Figure 2.5: Three-County Job Change (Thousands)

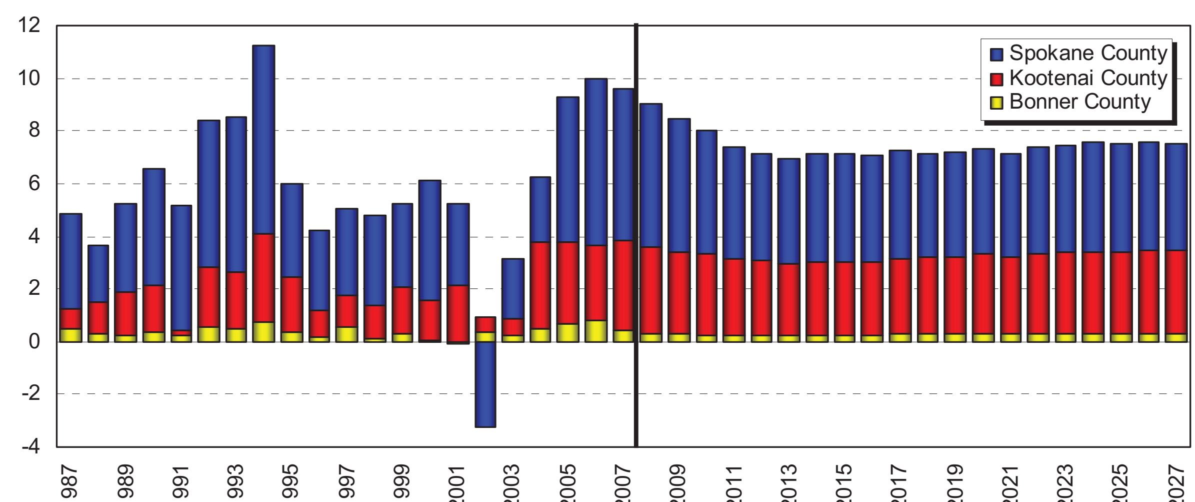
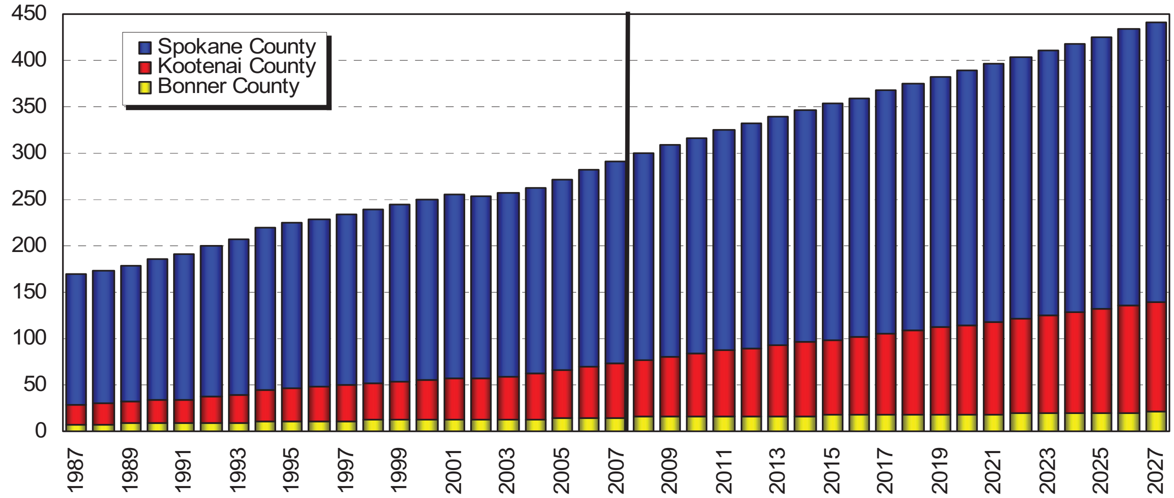


Figure 2.6: 3-County Non-Farm Jobs (Thousands)



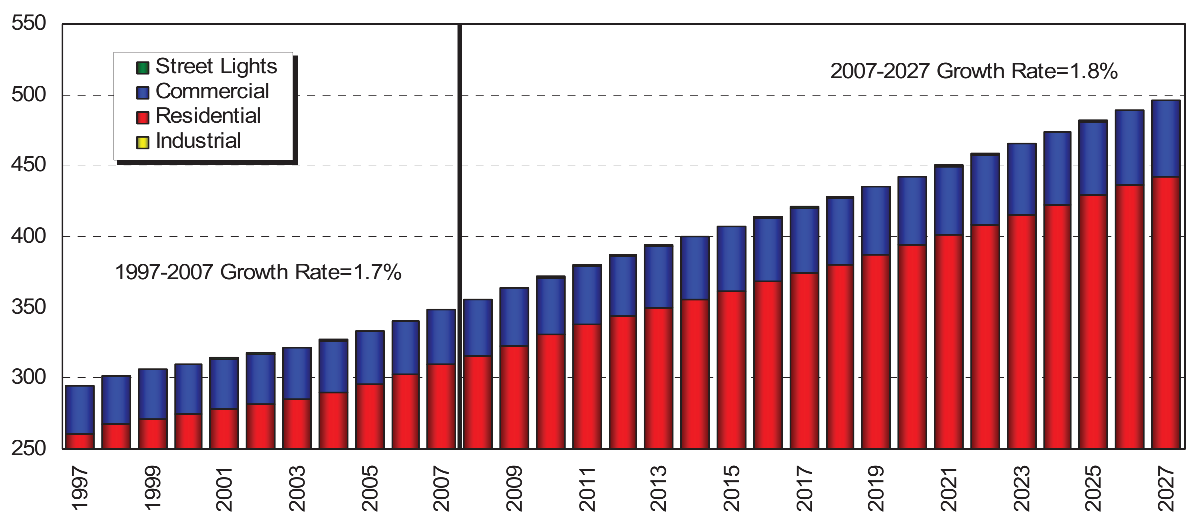
5.1 percent for Kootenai County and 2.1 percent for Spokane County. See Figure 2.6. Over the forecast horizon, growth rates are predicted at 2.6 percent, 3.6 percent and 2.6 percent, respectively. As indicated in the following chart, employment growth is expected to equal approximately 7,500 new jobs annually.

Customer growth projections follow from baseline economic forecasts. The company tracks four key customer classes–residential, commercial, industrial and street lighting. Residential customer forecasts are driven by population. Commercial forecasts rely more heavily on employment and residential growth trends. Industrial customer growth is correlated with employment growth. Street lighting trends with population growth.

Avista forecasts sales by rate schedule. The overall customer forecast is a compilation of the various rate schedules of our served states. For example, the residential class forecast is comprised of separate forecasts prepared for rate schedules 1, 12, 22 and 32 for Washington and Idaho. See Figure 2.7

Avista served 300,928 residential customers, 37,911 commercial customers, 1,388 industrial customers and 425 street lighting customers, or a total of 340,652 retail

Figure 2.7: Avista Annual Average Customer Forecast (Thousands)



electricity customers in 2006. The 2027 forecast predicts 440,789 residential, 53,322 commercial, 1,795 industrial and 625 street lighting customers for a grand total of 496,532. The 20-year compound growth rate averages 2.8 percent.

WEATHER, PRICE ELASTICITY, PRICES, CONSERVATION AND USE PER CUSTOMER

Weather Forecasts

The baseline electricity sales forecast is based on 30-year normal temperatures for the station at the Spokane International Airport, as tabulated by the National Weather Service from 1971 through 2000. Daily values go back as far as 1890. There are several other weather stations with historical records in the company's electric service area; however that data is available over a much shorter duration. Sales forecasts are prepared using monthly data, as more granular load information is not available. The company finds high correlations between the Spokane International Airport and other weather stations in its service territory. It uses heating degree days to measure cold weather and cooling degree days to measure hot weather in its retail sales forecast.

In response to questions from its Technical Advisory Committee, the company has prepared a study of the possible impacts of climate change on its retail load forecast. Ample evidence of cooling and warming trends exists in the 115-year record. In recent years the trend has been one of a warming climate when compared to the 30-year normal. Recent trends in heating and cooling degree days for Spokane are roughly equal to the scientific community's predictions for this coordinate on the globe, implying a one-degree warming every 25 years. Extrapolating the trend finds that in 20 years summer load would be approximately 26 aMW, a 2.6 percent, higher than the Base Case. In the winter, loads would be approximately 40 aMW, or 2 percent, lower. This change likely would occur gradually, and it appears that approximately one-third to one-half of this trend is already captured in our load forecast. The company will continue to study these data trends in its two-year Action Plan and report any additional findings in the 2009 Integrated Resource Plan.

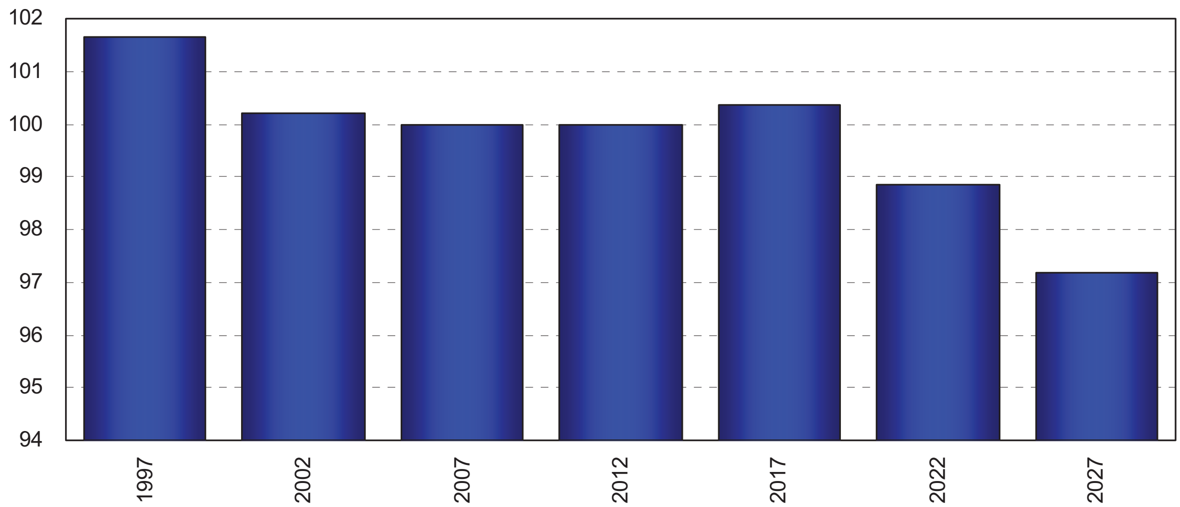
Price Elasticity

Price elasticity is a central economic concept of projecting electricity demand. Price elasticity of demand is the ratio of the percent change in the quantity demanded of a good or service to a percentage change in its price. In other words, elasticity measures the responsiveness of buyers to changes in electricity prices. A consumer who is sensitive to price changes has a relatively elastic demand profile. A customer who is unresponsive to price changes has a relatively inelastic demand profile. During the 2000-01 energy crisis customers showed their sensitivity, or price elasticity, of demand, reducing their overall electricity usage in response to price increases.

Cross elasticity of demand, or cross-price elasticity, is the ratio of the percentage change in the quantity demanded of one good to a one percent change in the price of another good. A positive coefficient indicates that the two products are substitutes; a negative coefficient indicates they are complementary goods. Substitute goods are replacements for one another. As the price of the first good increases relative to the price of the second good, consumers shift their consumption to the second good. Complementary goods are used together; increases in the price of one good result in a decrease in demand for the second good along with the first. The principal cross elasticity impact on electricity demand is the substitutability of natural gas in some applications, including water and space heating.

Income elasticity of demand is the ratio of the percentage change in the quantity demanded of one good to a 1 percent change in consumer income. Income elasticity measures the responsiveness of consumer purchases to

Figure 2.8: Household Size Index (% of 2007 Household Size)



income changes. Two impacts affect electricity demand. The first is affordability. As incomes rise, a consumer's ability to pay for goods and services increases. The second income-related impact is the amount and number of customers using equipment within their homes and businesses. Simply stated, as incomes rise consumers are more likely to purchase more electricity-consuming equipment, live in larger dwellings and use their electrical equipment more often.

The correlation between retail electricity prices and the commodity cost of natural gas has increased in recent years. We estimate customer class price elasticity in our computation of electricity and natural gas demand. Residential customer price elasticity is estimated at negative 0.15. Commercial customer price elasticity is estimated at negative 0.10. The cross-price elasticity of natural gas and electricity is estimated to be positive 0.05. Income elasticity is estimated at positive 0.75, meaning electricity is more affordable as incomes rise.

Retail Price Forecast

The retail sales forecast is based on retail prices increasing an average of 3.5 percent annually from 2007 to 2027. The rate changes are lumpy, rising by 17.5 percent every five years (five percent above the overall inflation rate).

Conservation

It is very difficult to separate the interrelated impacts of rising electricity and natural gas prices, rising incomes and conservation programs. We only have data on total demand and must derive the impacts associated with consumption changes. The company has offered conservation programs to its customers since 1978. The impact of conservation on electrical usage is fully imbedded in the historical data; therefore, we concluded that existing conservation levels (5 aMW) are imbedded in the forecast. Where conservation acquisition decreases from this level, retail load obligations would increase. As this IRP forecasts growing conservation acquisition, this growth reduces retail load obligations.

Use per Customer Projections

Monthly electricity sales and customers by rate schedule, customer class and state from 1997 to 2006 make up the database used to project usage per customer. Historical data is weather-normalized to remove the impact of heating and cooling degree day deviations from expected normal values, as discussed above. Retail electric price increase assumptions are applied to price elasticity estimates to estimate price-induced reductions in electrical use per customer.

The underlying increase in residential use per customer over the long term is 0.5 percent per year, consistent with the income elasticity and growth rate per customer. As shown by Figure 2.8, the number of persons per household declines slightly over the next 20 years.

Residential customers tend to be homogeneous relative to the size of their dwellings. Commercial customers, on the other hand, are heterogeneous, ranging from small customers with varying electricity intensity per square foot of floor space to big box retailers with generally high intensities. The addition of new large commercial customers, specifically the largest universities and hospitals, can greatly skew the average use per average customer. Customer usage is illustrated in Figure 2.9. Estimates for residential usage per customer across all schedules are relatively smooth. Commercial usage per customer is forecast to increase for several years, due to additional buildings either built or anticipated to be built at several existing very large customers and in particular at Washington State University campuses in Spokane and Pullman. For very large customers, we include expected additions through 2011; after 2011 no additions are included in the forecast. We will include publicly-announced long lead time buildings into the forecast included in future IRPs.

RETAIL ELECTRICITY SALES FORECAST

Between 1997 and 2006 the region was affected by major economic changes, not the least of which was a marked increase in retail electricity prices. The energy crisis of 2000-01 included the implementation of widespread, permanent conservation efforts by our customers. In 2004, rising retail electricity rates further reinforced conservation efforts. Several large industrial facilities served by the company closed permanently during the 2001-02 economic recession.

The electric retail sales forecast takes a somewhat conservative approach by assuming closures are permanent. If these industrial facilities reopen, the annual electricity retail sales forecast presented in this plan will be adjusted. Retail electricity consumption rose 2.3 percent annually from 1997 through 2006. This increase was despite the combined impacts of higher prices and decreased electricity demand during the energy crisis. The forecasted average annual increase in firm sales over the 2007 to 2027 period is 2.0 percent.

The sales forecast takes a "bottom up" approach, summing forecasts of the number of customers and usage per customer to produce a retail sales forecast. Individual forecasts for our largest industrial customers (Schedule 25) include planned or announced production increases

Figure 2.9: Use per Customer

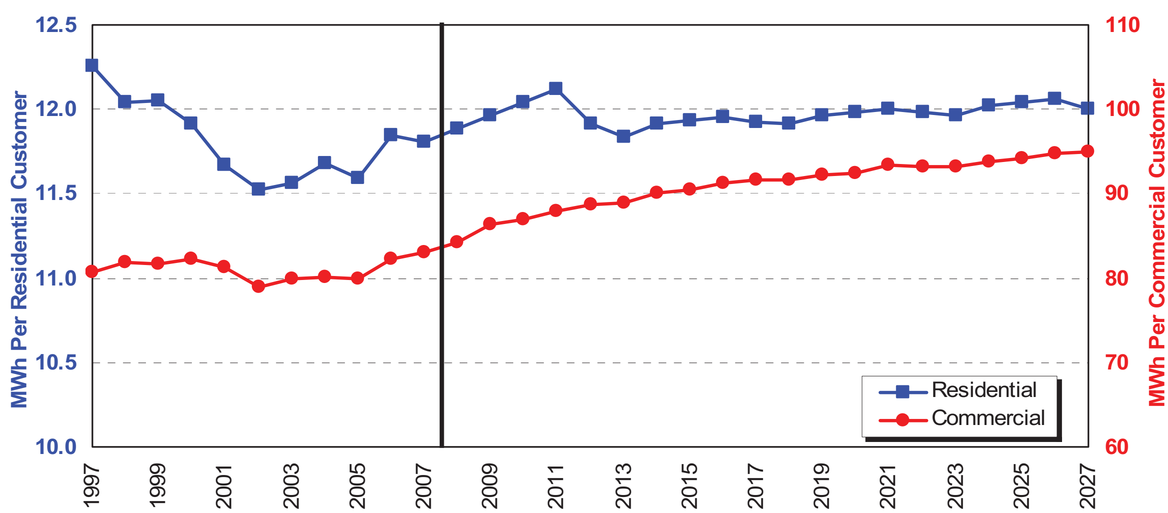
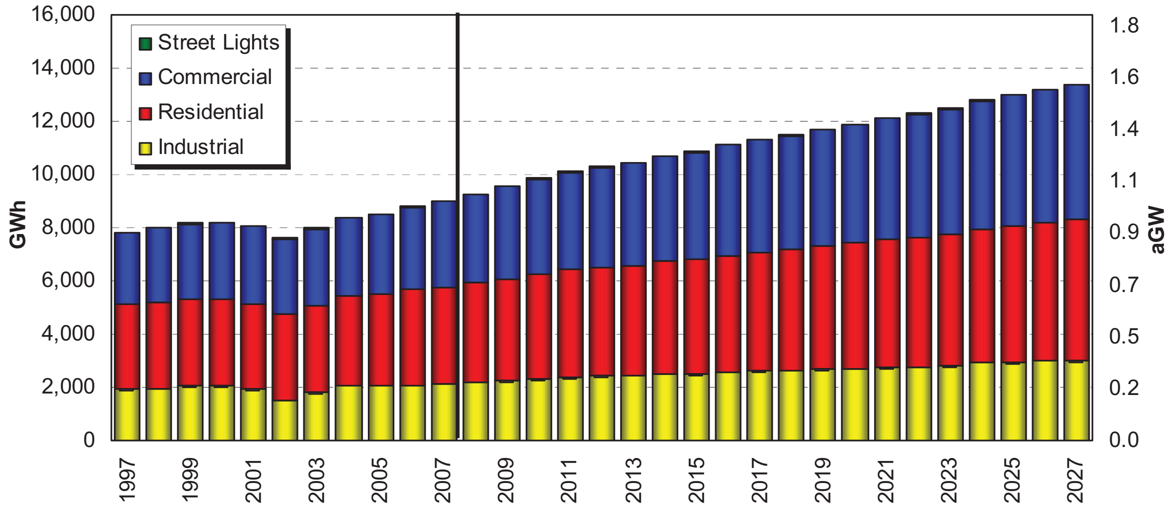


Figure 2.10: Avista's Retail Sales Forecast



or decreases. Lumber and wood products industries are ramping down from very high production levels, which is consistent with the decline in housing starts at the national level. The load forecasts for these sectors were reduced to account for decreased production levels. Anticipated sales to aerospace and aeronautical equipment suppliers have increased and local plants have announced plans to hire more workers and increase their output.

Actual (i.e., not weather corrected) retail electricity sales to Avista customers in 2006 were 8.78 billion kWh. Heating degree days in 2006 were 93 percent of normal, almost completely offset in terms of energy use by 156 percent of normal cooling degree days. The forecast for 2027 is 13.4 billion kWh, representing a 2.0 percent compounded increase in retail sales. See Figure 2.10.

Load Forecast

Load forecasts are derived from retail sales. Retail sales in kilowatt hours are converted into average megawatt hours using a regression model to ensure monthly load shapes conform to history. The company's load forecast is termed its Native Load. Native Load is net of line losses across the Avista transmission system.

Native Load growth is indicated in Figure 2.11. Note the significant drop in 2001 during the energy

Figure 2.11: Annual Net Native Load (aMW)

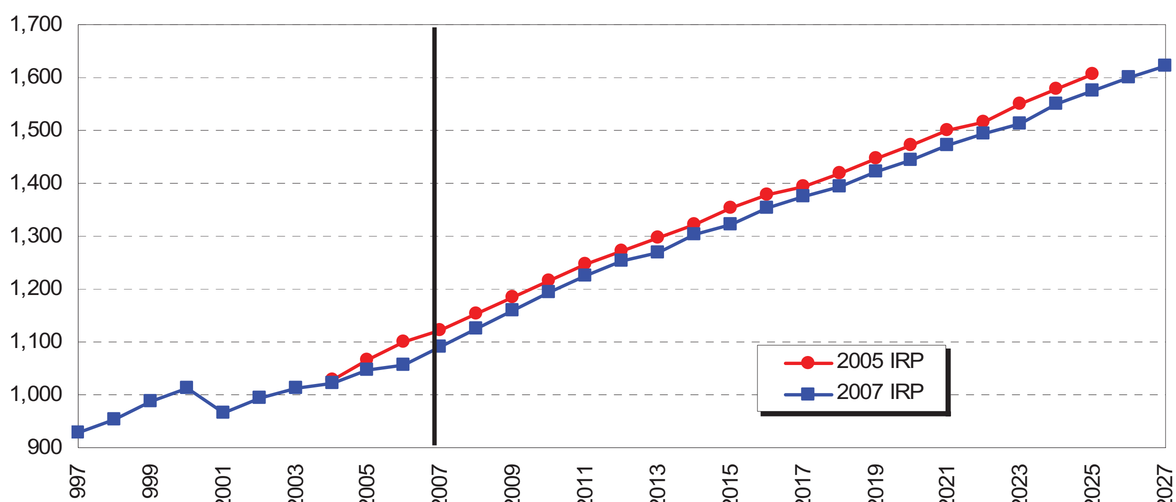
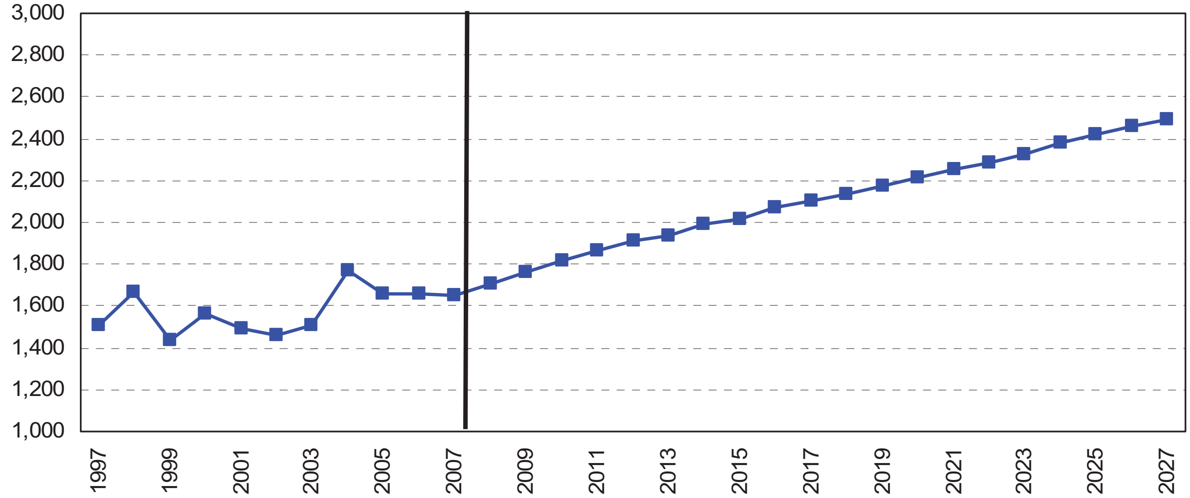


Figure 2.12: Calendar Year Peak Demand (MW)



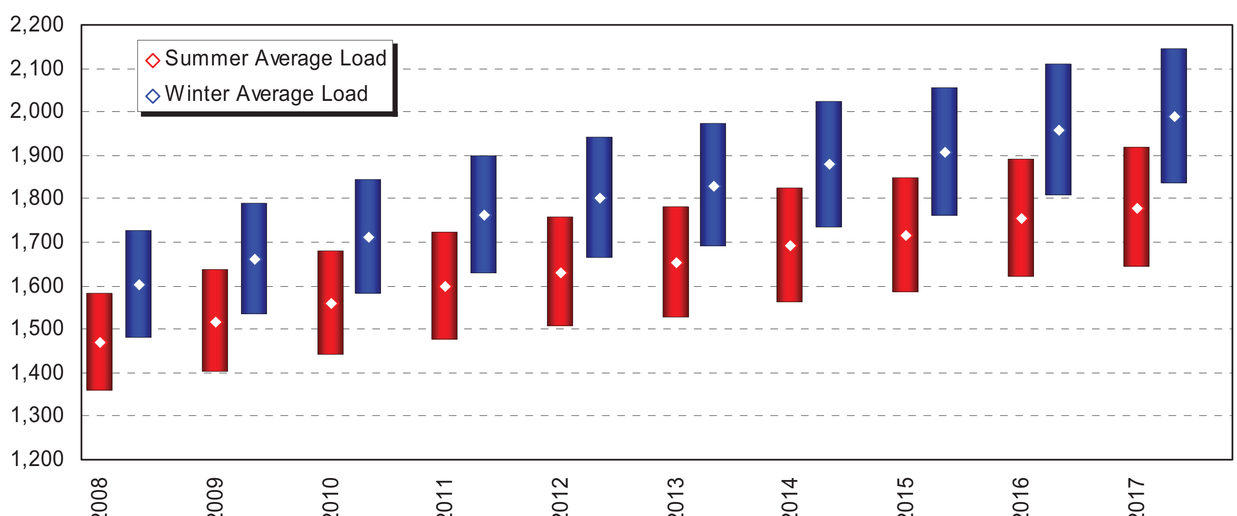
crisis. The loads from 1997 to 2006 are not weather normalized. The 2005 IRP load forecast is presented for comparison purposes. Loads are modestly lower in the 2007 IRP compared with the 2005 IRP.

Peak Demand Forecast

The peak demand forecast in each year represents the most likely value for that year. It does not represent the extreme peak demand. In statistical terms, the most likely peak demand has a 50 percent chance of exceedance in any year. The peak forecast is produced by running a regression between actual peak demand and net native load. The peak demand forecast is in Figure 2.12. Peak loads are expected to grow at 2.4 percent between 2007 and 2017 (400 MW) and 2.1 percent over the entire 20-year forecast.

Historical data are significantly influenced by extreme weather data. The comparatively low 1999 peak demand figure was the result of a warmer-than-average winter peak day; the peak in 2006 was the result of a below-average winter peak day. The 1999 and 2006 peak demand values illustrate why relying on compound growth rates for the peak demand forecast is an oversimplification and why the company plans to own or control enough generation assets and contracts to exceed expected peak demand.

Figure 2.13: Comparison of Summer and Winter Peak Demand (MW)



Avista has witnessed significant summer load growth as air conditioning penetration has risen in its service territory. That said, Avista expects to remain a winter-peaking utility in the foreseeable future. It is possible that very mild winter weather and extremely hot summertime temperatures could result in our summer peak load exceeding our wintertime demand level. This will be an anomaly. Figure 2.13 illustrates our forecast of winter and summer peak demands through 2017 and the expected range of the forecasts at the 80 percent confidence level. We expect that loads in the summer and winter of each year have a 10 percent probability of being higher than shown. Winter peak demand exceeds summer peak demand in all years; the possibility of a summer peak being higher than a winter peak in the same year is possible.

FORECAST SCENARIOS

The discussion so far has concentrated on the Base Case, or most-likely, electricity sales forecast. Forecasting is inherently uncertain, and alternative electricity growth scenarios are used to provide insight and guidance for our resource acquisition plans. At the request of the Technical Advisory Committee, high and low economic forecasts were prepared to illustrate how variable our load forecast might be.

The principal driver of these alternatives is the standard deviation of annual loads between 1997 and 2006. The average growth rate for the 10-year period was 2.4 percent, and the standard deviation was 2.5 percent. Approximately 75 percent of year-on-year variation is driven by weather, leaving 25 percent to the non-weather factors we are interested in evaluating here. The 80 percent confidence interval (with a 10 percent chance of exceedance on the high side and a 10 percent chance of exceedance on the low side) produced a range of growth for the 20-year period between 0.9 percent and 3.1 percent. This range is roughly in line with other Pacific Northwest forecast scenarios.

Avista is not forecasting any changes to its service territory in these scenarios. Such changes, were they to occur, would be outside of the scope of this exercise. Alternative forecasts are presented in Figure 2.14. Developed specifically for the IRP, these alternative forecasts should not be confused with other company or agency forecasts. The scenarios are not boundary forecasts in that the high forecast should not be considered the highest possible load trajectory; the low forecast does not represent the lowest possible forecast.

Figure 2.14: Electric Load Forecast Scenarios (aMW)

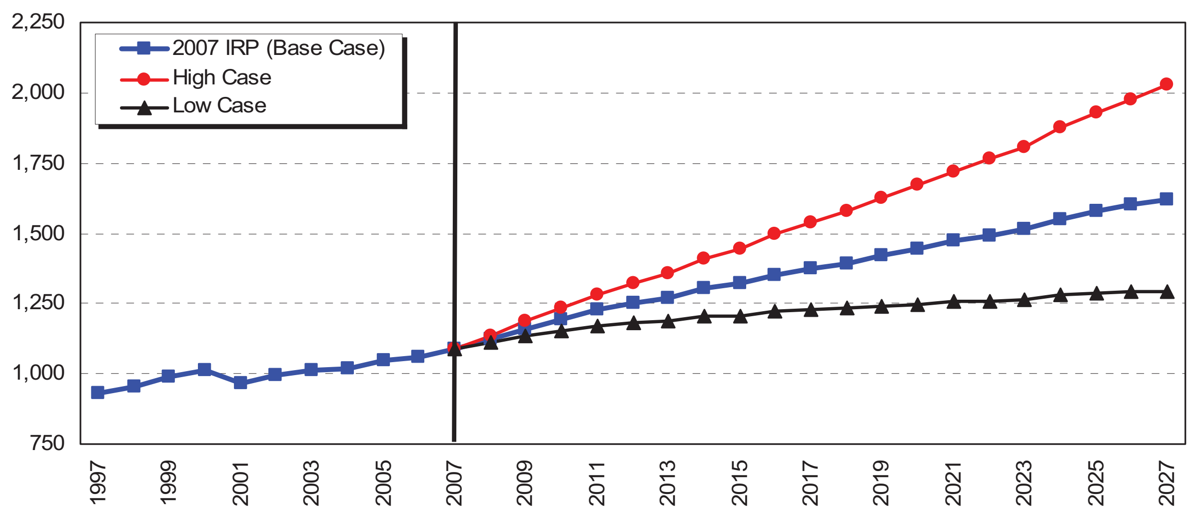
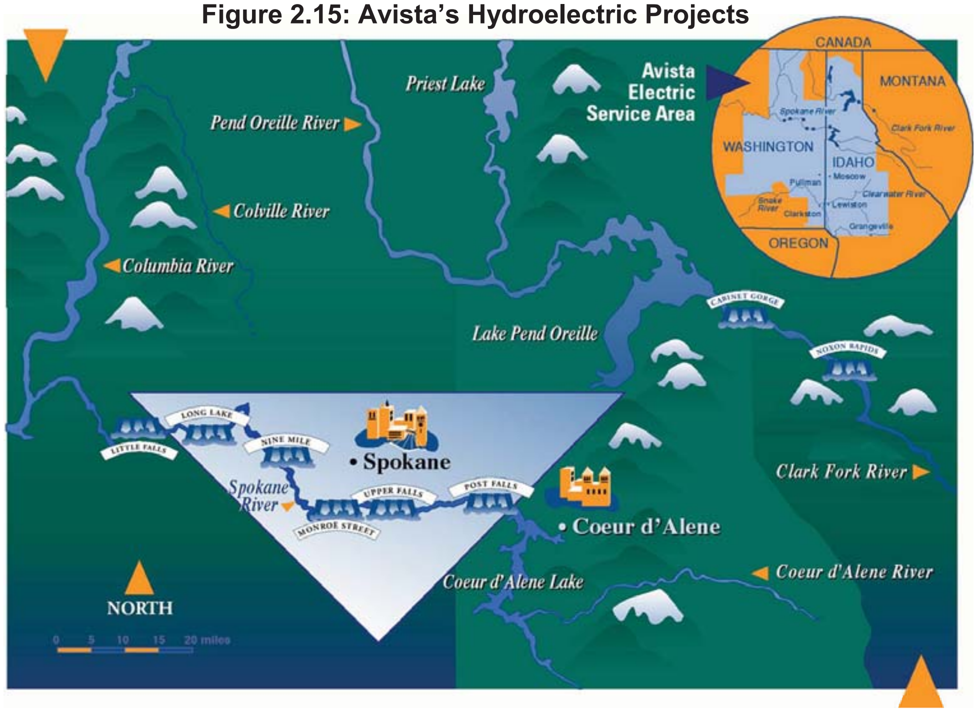


Figure 2.15: Avista's Hydroelectric Projects



LOADS & RESOURCES

The company relies on a diversified portfolio of generating assets to meet customer loads. Avista owns and operates eight hydroelectric projects located on the Spokane and Clark Fork Rivers. Its thermal assets include partial ownership of two coal-fired units in Montana, three natural gas-fired projects within its service territory, another natural gas-fired project in Oregon and a biomass plant near Kettle Falls, Washington.

SPOKANE RIVER HYDROELECTRIC PROJECTS

Avista owns and operates six hydroelectric projects on the Spokane River. FERC licensing for these projects expires on July 31, 2007 (except for Little Falls, which is state licensed). The company is actively working with stakeholders on relicensing for the Spokane River Project. Following is a short description of the Spokane River projects, including the maximum capacity and nameplate ratings for each plant. The maximum capacity of a generating unit is the total amount of electricity that a particular plant can safely generate. This is often higher than the nameplate rating because of facility upgrades. The nameplate, or installed capacity of a plant, is the plant's capacity as rated by the manufacturer. Figure 2.15 is a map of all company-owned hydroelectric projects.

Post Falls

The Post Falls plant, located at its Idaho namesake, began operation in 1906. Generation was expanded in 1980 with an additional unit. This plant has an 18.0 MW maximum capability and a 14.8 MW nameplate rating.

Upper Falls

The Upper Falls project began generating in 1922 in downtown Spokane. This project is comprised of a single unit with a 10.2 MW maximum capability and 10.0 MW nameplate rating.

Monroe Street

The Monroe Street plant was the company's first generating unit. It started service in 1890 near what is now Riverfront Park. Rebuilt in 1992, the single generating unit now has a 15.0 MW maximum capability and a 14.8 MW nameplate rating.

Nine Mile

The Nine Mile project was built by a private developer in 1908 near Nine Mile Falls, Washington. The company purchased it in 1925 from the Spokane & Eastern Railway. Its four units have a 24.4 MW maximum capability and a 26.4 MW nameplate rating.

Long Lake

The Long Lake project is located above Little Falls in Eastern Washington. It was the highest spillway dam with the largest turbines in the world when it was completed in 1915. The plant was most recently upgraded with new runners in 1999. The four units in this project provide 90.4 MW in combined maximum capability and 70.0 MW nameplate rating.

Little Falls

The Little Falls project was completed in 1910 near Ford, Washington. The four units at this project provide 36.0 MW of maximum capability and have a 32.0 MW nameplate rating.

CLARK FORK RIVER HYDROELECTRIC PROJECT

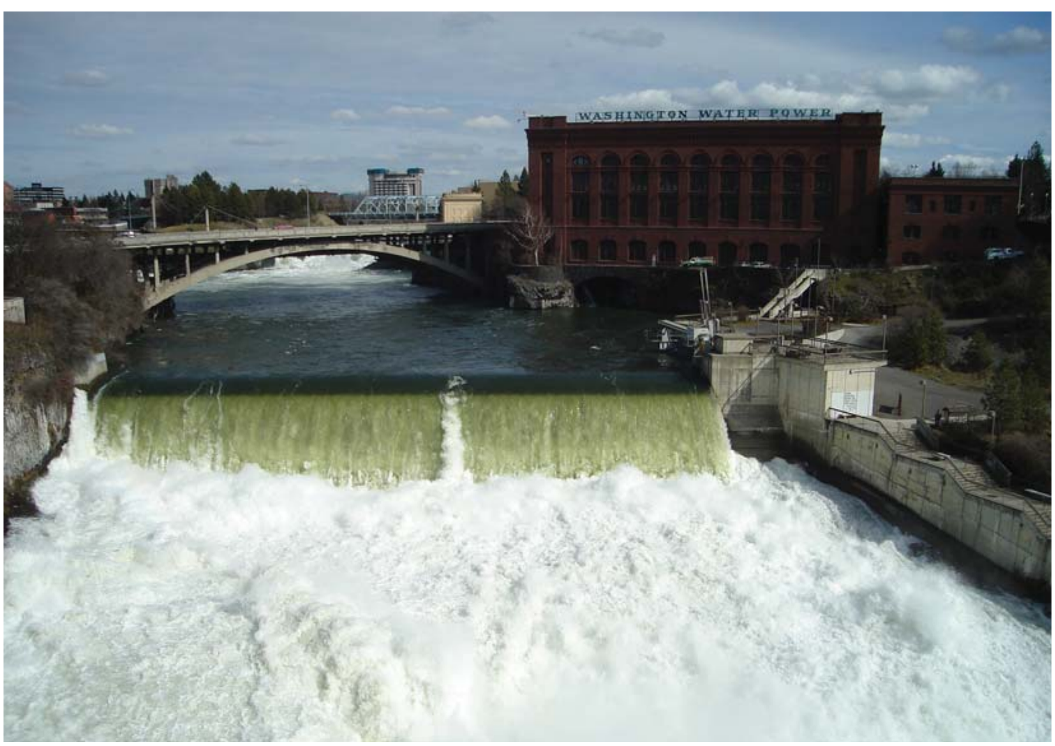
The Clark Fork River Project is comprised of hydroelectric projects in Clark Fork, Idaho, and Noxon, Montana. The plants operate under a FERC license expiring in 2046.

Cabinet Gorge

The Cabinet Gorge plant started generating power in 1952 with two units. The plant was expanded with two additional generators in the following year. The current maximum capability of the plant is 263.2 MW; it has a nameplate rating of 272.2 MW. Upgrades at this project began with the replacement of turbine Unit 1 in 1994. Unit 3 was upgraded in 2001. Unit 2 was upgraded in 2004. The final unit, Unit 4, received a $6 million turbine upgrade in 2007, increasing its generating capacity from 55 MW to 64 MW and adding 2.1 aMW of energy.

Noxon Rapids

The Noxon Rapids project includes four generators



Monroe Street Hydroelectric Facility, Spokane, Washington

Table 2.2: Company-Owned Hydro Resources

Project Name	River System	Location	Project Start Date	Nameplate Capacity (MW)	Maximum Capability (MW)	70-Year Energy (aMW)
Monroe Street	Spokane	Spokane, WA	1890	14.8	15.0	13.2
Post Falls	Spokane	Post Falls, ID	1906	14.8	18.0	9.9
Nine Mile	Spokane	Nine Mile Falls, WA	1925	26.4	24.4	16.4
Little Falls	Spokane	Ford, WA	1910	32.0	36.0	22.8
Long Lake	Spokane	Ford, WA	1915	70.0	90.4	52.4
Upper Falls	Spokane	Spokane, WA	1922	10.0	10.2	8.8
Cabinet Gorge	Clark Fork	Clark Fork, ID	1952	272.2	263.2	122.2
Noxon Rapids	Clark Fork	Noxon, MT	1959	466.2	527.0	202.9
Total	**All Hydro**			**905.4**	**984.2**	**442.9**

Table 2.3: Company-Owned Thermal Resources

Project Name	Location	Fuel	Start Date	Nameplate Capacity (MW)	Maximum Capability (MW)	Energy Capability (aMW)
Colstrip 3 (15%)	Colstrip, MT	Coal	1984	116.7	114.6	93.3
Colstrip 4 (15%)	Colstrip, MT	Coal	1986	116.7	114.6	93.3
Rathdrum	Rathdrum, ID	Gas	1995	166.5	176.0	135.6
Northeast	Spokane, WA	Gas/Oil	1978	62.8	66.8	9.8
Boulder Park	Spokane, WA	Gas	2002	24.6	24.6	23.2
Coyote Springs 2	Boardman, OR	Gas	2003	287.0	284.7	250.2
Kettle Falls	Kettle Falls, WA	Wood	1983	46.0	50.7	42.2
Kettle Falls CT	Kettle Falls, WA	Gas	2002	6.9	6.9	6.1
Total	**All Thermal**			**827.2**	**838.9**	**653.7**

installed between 1959 and 1960, and a fifth unit added in 1977. The current plant configuration has a maximum capability of 527.0 MW and a nameplate rating of 466.2 MW. Upgrades to all four units at the Noxon Rapids facility are scheduled from March 2009 to March 2012. The upgrades are expected to add 38 MW of capacity and 6 aMW of energy to the company's resource portfolio.

Total Hydroelectric Generation

In total, our hydroelectric plants are capable of generating as much as 984.2 MW. Table 2.2 summarizes the company's hydro projects. This table also includes the average annual energy output of each facility based on the 70-year stream flow record.

THERMAL RESOURCES

Avista owns and maintains several thermal assets located across the Northwest. Each thermal plant is expected to continue to be available through the 20-year duration of the 2007 IRP. The company's thermal resources provide dependable low-cost energy to serve base loads and provide peak load serving capabilities. Table 2.3 summarizes the company's thermal projects.

Colstrip

The Colstrip plant, located in Eastern Montana, consists of four coal-fired steam plants owned by a group of utilities. PPL Global operates the facilities. Avista owns 15 percent of Units 3 and 4. Unit 3 was completed in 1984 and Unit 4 was finished in 1986. The company's share of each Colstrip unit has a maximum capability of 114.6 MW and a nameplate rating of 116.7 MW. Capital improvements to both units were completed in 2006 and 2007 to improve efficiency and reliability and to increase generation. The upgrades included new high-pressure steam turbine rotors and conversion from analog to digital control systems. These capital improvements increased the company's share of generation by 4.2 MW at each unit without any additional fuel consumption.

Rathdrum

Rathdrum is a two-unit, simple-cycle, gas-fired plant located near Rathdrum, Idaho. The plant entered service in 1995. It has a maximum capability of 176.0 MW and a nameplate rating of 166.5 MW.

Northeast

The Northeast plant, located in northeast Spokane, is a two-unit, aero-derivative, simple-cycle plant completed in 1978. The plant is capable of burning natural gas or fuel oil, but current air permits prevent the use of fuel oil. The combined maximum capability of the units is 66.8 MW with a nameplate rating of 62.8 MW.

Boulder Park

The Boulder Park project was completed in Spokane Valley in 2002. The site uses six natural gas-fired internal combustion engines to produce a combined maximum capability and nameplate rating of 24.6 MW.

Coyote Springs 2

Coyote Springs 2 is a natural gas-fired combined cycle combustion turbine located near Boardman, Oregon. The plant began service in 2003. The maximum capability is 264.3 MW and the duct burner provides the unit with an additional capability of up to 20.4 MW. The nameplate rating is 287.0 MW.

Kettle Falls

The Kettle Falls biomass facility was completed in 1983 near Kettle Falls, Washington. The open-loop biomass steam plant is fueled by waste wood products and has a maximum capability of 50.7 MW. Its nameplate rating is 46 MW.

Kettle Falls CT

The Kettle Falls CT is a natural gas-fired combustion turbine that began service in 2002. It has a maximum capability rating of 6.9 MW. Exhaust heat from the plant is routed into the Kettle Falls biomass plant boiler to increase its efficiency. The plant is capable of running independently of the biomass steam plant.

POWER PURCHASE AND SALE CONTRACTS

The company utilizes several power supply purchase and sale arrangements of varying lengths to meet a portion of its load requirements. This section describes the contracts in effect during the scope of the 2007 IRP. The contracts provide a number of benefits to the company, including environmentally low-impact and low-cost hydro and wind power. An annual summary of our contracts is contained in Table 2.5.

Bonneville Power Administration (BPA) – Residential Exchange

The company first entered into settlement agreements to resolve BPA's Residential Exchange obligation on October 31, 2000. Over the first five years of the 10-year settlement, the company received financial benefits equivalent to purchasing 90 aMW at BPA's lowest cost-based rate. The company's benefit level increased to 149

Coyote Springs 2, Boardman, Oregon

aMW on October 1, 2006. At BPA's option, the 149 aMW may be provided in whole or in part as financial benefits or as a physical power sale; the IRP assumes the former based on regional discussions.

On May 3, 2007, the Ninth U.S. Circuit Court of Appeals issued opinions holding that BPA exceeded its settlement authority and acted in a manner that was inconsistent with the Northwest Power Act when it entered into the settlement agreements. As a result, on May 21, 2007, BPA notified Avista that it was suspending payments.

Bonneville Power Administration – WNP-3 Settlement

On September 17, 1985, the company signed settlement agreements with BPA and Energy Northwest (formerly the Washington Public Power Supply System or WPPSS), ending construction delay claims against both parties. The settlement provides an energy exchange through June 30, 2019, with an agreement to reimburse the company for certain WPPSS – Washington Nuclear Plant No. 3 (WNP-3) preservation costs and an irrevocable offer of WNP-3 capability for acquisition under the Regional Power Act.

The energy exchange portion of the settlement contains two basic provisions. The first provision provides approximately 42 aMW of energy to the company from BPA through 2019, subject to a contract minimum of 5.8 million megawatt-hours. The company is obligated to pay BPA operating and maintenance costs associated with the energy exchange as determined by a formula that ranges from $16 to $29 per megawatt-hour in 1987 dollars.

The second provision provides BPA approximately 33 aMW of return energy at a cost equal to the actual operating cost of the company's highest-cost resource. A further discussion of this obligation, and how the company plans to account for it, is covered under the Confidence Interval Planning heading of this chapter of the IRP.

Mid-Columbia Hydroelectric Contracts

During the 1950s and 1960s, various public utility districts (PUDs) in central Washington developed hydroelectric projects on the Columbia River. Each plant was large compared to the loads served by the PUDs. Long-term contracts were signed with public, municipal and investor-owned utilities throughout the Northwest to assist with project financing and to ensure a market for the surplus power.

The company entered into long-term contracts for the output of four of these projects "at cost." The contracts provide energy, capacity and reserve capabilities. In 2008 they will provide approximately 95 MW of capacity and 51 aMW of energy. Over the next 20 years, the Wells and Rocky Reach contracts will expire. While the company may be able to extend these contracts, it has no assurance today that extensions will be offered. The 2007 IRP does not include energy or capacity for these contracts beyond their expiration dates.

The company renewed its contract with Grant PUD in 2005 for power from the Priest Rapids project. The contract term will equal the term in the forthcoming Priest Rapids and Wanapum dam FERC licenses. A license term of 30 to 50 years is expected. The company acquired additional displacement power in the Priest Rapids settlement. Displacement power, through September 30, 2011, includes project output available due to displacement resources being used to serve Grant PUD's load. A summary of Mid-Columbia contracts is included in Table 2.4.

Medium-Term Market Purchases

Avista has power purchase contracts for 100 MW of power from 2004 through 2010 from several suppliers.

Table 2.4: Mid-Columbia Contract Summary

	2008		2012		2017	
Project Name	MW	aMW	MW	aMW	MW	aMW
Rocky Reach	37.7	20.0	0.0	0.0	0.0	0.0
Wells	28.6	15.8	28.6	15.8	28.6	15.8
Grant County	28.9	14.8	63.2	35.7	63.2	32.6
Totals	**95.2**	**50.6**	**92.8**	**52.5**	**92.8**	**48.4**

Nichols Pumping Station

The company provides energy to operate its share of the Nichols Pumping Station, which supplies water for the Colstrip plant. The company's share of the Nichols Pumping Station load is approximately one aMW. Avista is also under contract to provide pumping energy to other Colstrip owners.

Portland General Electric – Firm Capacity Sale

The company contracted to provide Portland General Electric (PGE) with 150 MW of firm capacity through December 31, 2016. PGE may schedule deliveries up to its capacity limit during any 10 hours of each weekday. Within 168 hours PGE returns energy delivered under the contract.

Stateline Wind Energy Center

The company contracted with PPM Energy in 2004 for 35 MW of nameplate wind capacity from the Stateline Wind Energy Center located on the Oregon-Washington border. This 35 MW contract does not include firming services.

A summary of all company obligations and rights is presented in Table 2.5.

RESERVE MARGINS

Planning reserves accommodate situations when loads exceed and/or resources are below expectations because of adverse weather, forced outages, poor water conditions or other contingencies. There are disagreements within the industry on adequate reserve margin levels. Many stem from system differences, such as resource mix, system size and transmission interconnections. For example, a hydro-based utility generally has a higher capacity-to-energy ratio than a thermal-based utility.

Reserve margins, on average, increase customer rates when compared to resource portfolios without reserves. For example, inexpensive 100 MW peaking resources overnight costs are around $42 million; this translates to a $6 million annual expense. Reserve resources have the physical capability to generate electricity, but high operating costs limit economic dispatch and the potential to create revenues to offset capital costs. Some argue

Table 2.5: Significant Contractual Rights and Obligations

Contract Name	Start Date	Capacity (MW)	Energy (aMW)	End Date
Grant County Purchase	2005	129.3	72.0	TBD
Rocky Reach Purchase	1961	37.7	19.3	Oct-2001
Wells Purchase	1967	28.6	9.9	Aug-2018
PGE Capacity Sale	1992	150.0	0.0	Dec-2016
Upriver Dam Purchase	1966	14.4	10.0	Dec-2011
WNP-3 Purchase & Sale	1987	82.0	48.0	Jun-2019
Medium-Term Purchases	2004	100.0	100.0	Dec-2010
PPM Wind Purchase [1]	2004	35.0	9.8	Mar-2011
Total Contract		**577.0**	**268.0**	

[1] The PPM wind purchase is shown at its nameplate rating.

that regions with deregulation, or "customer choice," provide strong incentives for industry participants to underestimate their reserve obligations and lower their costs at the expense of system reliability.

AVISTA'S PLANNING MARGIN

Avista's planning reserves are not directly based on unit size or resource type. Planning reserves are set at a level equal to 10 percent of our one-hour system peak load plus 90 MW. The 90 MW accounts for approximately 60 MW of hydro because of icing on river banks and 30 MW of Colstrip reserves because of coal handling problems in cold weather situations. This amounts to roughly a 15 percent planning reserve margin during the company's peak load hour.

CONFIDENCE INTERVAL PLANNING

Avista uses confidence interval planning to ensure it has resources adequate to meet customer energy requirements. Extreme weather conditions can affect monthly energy obligations by up to 30 percent. If the company lacks generation capability to meet high load variations, it is exposed to increased short term market volatility. Analysis of historical data indicates that an optimal criterion is the use of a 90 percent confidence interval based on the monthly variability of load and hydroelectric generation. This results in a 10 percent chance of the combined load and hydro variability exceeding the planning criteria for each month. In other words, there is a 10 percent chance that the company would need to purchase energy from the market in any given month. Avista has considered larger confidence intervals, but analysis suggests that the cost of additional resources to cover higher levels of variability would exceed the potential benefits. Building to the 99 percent confidence interval could significantly decrease the frequency of market purchases but would require approximately 200 MW of additional generation capability. Additional capital expenditures to support this level of reliability would put upward pressure on retail rates.

The 90 percent confidence level varies between 84 aMW and 301 aMW on a monthly basis in 2008, or 166 aMW across the 12-month period. This level is similar to critical water planning on an annual basis, but is more precise because it is based on the monthly instead of annual chance of exceedance.

Additional variability is inherent in the WNP-3 contract with BPA. The contract includes a return energy provision that can equal 33 aMW annually. The contract would be exercised under adverse conditions, such as low hydroelectric generation or high loads, which the company would also expect to be experiencing. Requirements under the confidence interval are increased by 33 aMW to account for the WNP-3 obligation through its expiration in 2019.

SUSTAINED PEAKING CAPACITY

Parallel to planning margins is the "gray area" between energy and capacity planning termed sustained peaking capacity. Sustained peaking capacity is a tabulation of loads and resources over a period exceeding

Table 2.6: Capacity L&R Versus Sustained Capacity

Item	Capacity L&R	Sustained Capacity
Period	One Hour	One Hour to Three Days or More
Peak Load	Average Coldest Day Temperature	Highest Load on Record
Thermals	Lowest Temperature & Colstrip Reduced for Freeze (~30 MW)	Lowest Temperature & Colstrip Reduced for Freeze (~30 MW)
Hydro	Maximum Capability Reduced for Freeze (~60 MW)	Maximum Capability Reduced for Freeze (~60 MW)
Contracts	Actual Forecast	Actual Forecast

the traditional one-hour definition. It is also a measure of reliability and recognizes that peak loads do not stress the system for just one hour. Table 2.6 details the assumption differences between the company's planning approach and the sustained capacity approach.

The company has actively participated in the Northwest Power and Conservation Council's Resource Adequacy committees over the past few years. Preliminary work indicates that the Northwest should carry approximately a 25 percent planning margin in the wintertime and a 17 percent planning margin in the summertime. These levels are much higher than the 12 to 15 percent levels recommended in California or for other markets, primarily due to the Northwest's heavier reliance on hydroelectric generation. Given the various uncertainties surrounding these higher planning margin levels, and the fact that they are not yet finalized, the company's plan will not change for this planning cycle. Avista will continue to participate in this important regional process and use the results in its future planning when they become more finalized.

RESOURCE REQUIREMENTS

The differences between loads and resources illustrate potential needs the company must address through its future resource acquisition actions. The company plans to meet both its energy and capacity needs.

CAPACITY TABULATION

The company regularly develops a 20-year service territory forecast of peak capacity loads and resources. Peak load is the maximum one-hour obligation, including operating reserves, on the expected average coldest day in January. Peak resource capability is the maximum one hour generation capability of company resources, including net contract contribution, at the time of the one-hour system peak. This calculation is performed to ensure that the company has sufficient resources to meet its load obligations. Avista has surplus capacity through 2009 without the addition of the Lancaster plant. Capacity deficits begin in 2010, with loads exceeding resource capabilities by five MW. The deficits continue to grow as peaking requirements

Table 2.7: Loads & Resources Capacity Forecast (MW)

	2008	2009	2010	2011	2012	2015	2017	2020	2027
Obligations									
Retail Load	1,703	1,763	1,815	1,868	1,909	2,019	2,103	2,214	2,492
Planning Margin	260	266	272	277	281	292	300	311	339
Total Obligations	***1,964***	***2,029***	***2,087***	***2,145***	***2,190***	***2,311***	***2,404***	***2,525***	***2,831***
Existing Resources									
Hydro	1,142	1,154	1,121	1,128	1,084	1,098	1,098	1,070	1,070
Net Contracts	172	172	173	73	58	58	208	128	128
Coal	230	230	230	230	230	230	230	230	230
Biomass	50	50	50	50	50	50	50	50	50
Gas Dispatch	308	308	308	308	308	308	308	308	308
Gas Peaking Units	211	211	211	211	211	211	211	211	211
Total Existing Resources	***2,111***	***2,123***	***2,092***	***1,999***	***1,939***	***1,954***	***2,104***	***1,996***	***1,996***
Net Positions	**148**	**94**	**5**	**-146**	**-251**	**-357**	**-300**	**-530**	**-835**
Planning Margins (%)	**24.0**	**20.4**	**15.2**	**7.0**	**1.6**	**-3.2**	**0.0**	**-9.9**	**-19.9**
Lancaster	0	0	275	275	275	275	275	275	0
Net Positions with Lancaster	**148**	**94**	**280**	**129**	**24**	**-82**	**-25**	**-255**	**-835**
Planning Margins with Lancaster (%)	**24.0**	**20.4**	**30.4**	**21.7**	**16.0**	**10.4**	**13.1**	**2.6**	**-19.9**

Figure 2.16: Capacity Loads and Resources (MW)

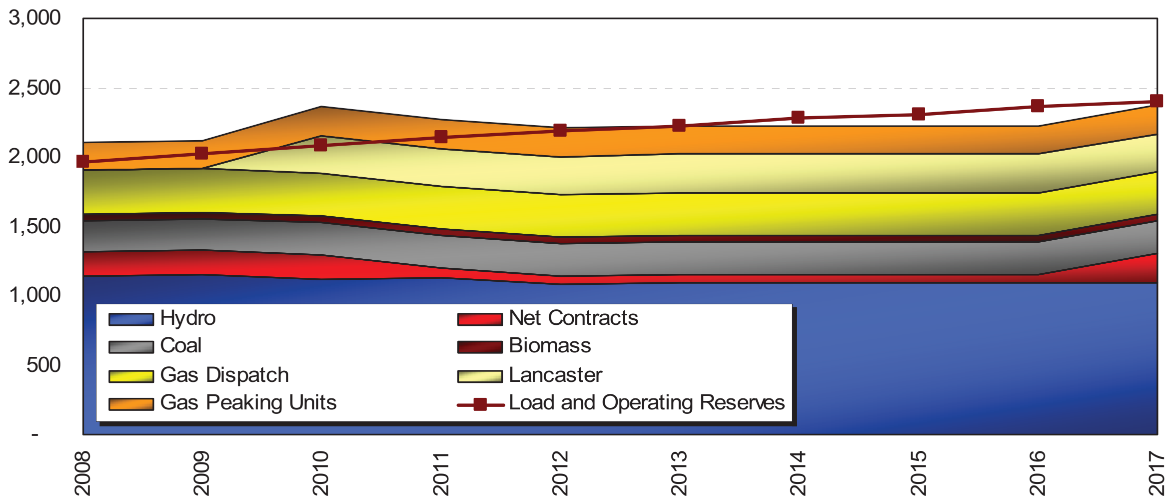


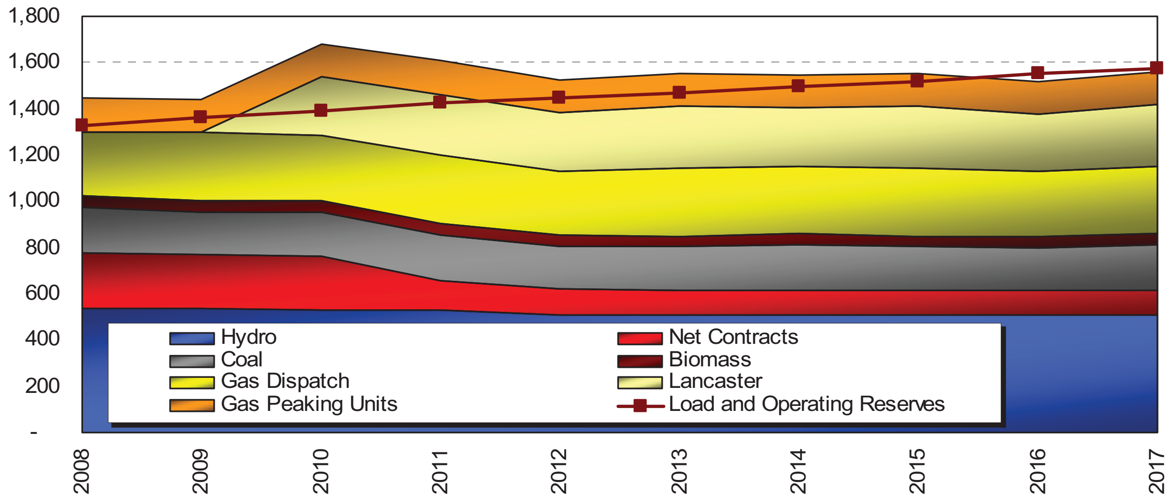
Table 2.8: Loads & Resources Energy Forecast (aMW)

	2008	2009	2010	2011	2012	2015	2017	2020	2027
Obligations									
Retail Load	1,125	1,163	1,196	1,230	1,256	1,326	1,379	1,450	1,627
90% Confidence Interval	200	199	196	196	192	192	192	156	156
Total Obligations	***1,324***	***1,362***	***1,392***	***1,425***	***1,448***	***1,518***	***1,571***	***1,606***	***1,783***
Existing Resources									
Hydro	540	538	531	528	512	510	509	491	491
Net Contracts	234	234	234	129	107	105	105	106	106
Coal	199	183	188	198	187	187	198	199	186
Biomass	47	47	47	47	47	47	47	47	47
Gas Dispatch	280	295	285	295	280	295	295	280	295
Gas Peaking Units	145	145	141	146	145	146	145	141	145
Total Existing Resources	***1,446***	***1,442***	***1,426***	***1,342***	***1,278***	***1,290***	***1,299***	***1,265***	***1,270***
Net Positions	**121**	**79**	**33**	**-83**	**-170**	**-228**	**-272**	**-341**	**-513**
Lancaster	0	0	254	264	249	264	264	228	0
Net Positions with Lancaster	**121**	**79**	**288**	**181**	**79**	**37**	**-8**	**-114**	**-513**

increase with load growth, and the company's resource base declines due to the expiration of market purchases and reductions in power from Mid-Columbia hydroelectric project contracts. Some year-to-year variation occurs in the forecast because of maintenance schedules. With Lancaster included in the planning, our deficit year moves out to 2014. Table 2.7 summarizes the forecast.

Avista currently has sufficient capacity resources, primarily because of the relatively large amount of hydroelectric generation in its resource portfolio. Hydroelectric resources can provide large amounts of short-term capacity in relation to the energy they produce because of storage associated with each project. Future capacity requirements will be addressed by acquiring new resources that provide both energy and capacity, or in the case of intermittent resources like wind, other resources that provide capacity. Figure 2.16 shows this information graphically.

Figure 2.17: Energy Loads and Resources (aMW)



ENERGY TABULATION

Table 2.8 summarizes annual energy loads and resources for the IRP time horizon. This IRP focuses on meeting the company's energy requirements to the 90 percent confidence level. Similar to Table 2.8, maintenance schedules affect the output of plants over the IRP timeframe. Specifically, coal, biomass, gas dispatch and gas peaking units are affected.

After 2010 new resources are necessary to continue meeting the 90 percent confidence interval planning margin criterion. The table shows that the company is annually in a surplus position through 2010. With the Lancaster plant, our surplus position moves out to 2016. Figure 2.17 provides the same information graphically.

Conservation acquisitions are prescriptive, meaning that customers must take action to lower their energy usage. Without "programmatic" conservation acquisitions, retail loads and supply-side resource acquisitions would be higher. Historically, conservation acquisition levels were included as reductions to retail load. The 2005 IRP included load that will be met by programmatic conservation, as an increase to load, and then displays the conservation resource separately in the table. The conservation projections shown in Tables 2.7 and 2.8 are cumulative and illustrate the company's commitment to continued acquisition of cost-effective conservation. Activities beyond current levels are discussed in Chapter 3 – Demand Side Management – and are shown as new resources in later tabulations.

The company expects to experience energy deficits during some months of all forecast years. As an example, the company anticipates deficits in January and October of 2008 even though the annual position has a 121 aMW surplus. Surplus positions occur in the remaining months, particularly during spring runoff. The company balances its monthly positions through short-term market purchases or sales, exchanges, or other resource arrangements.

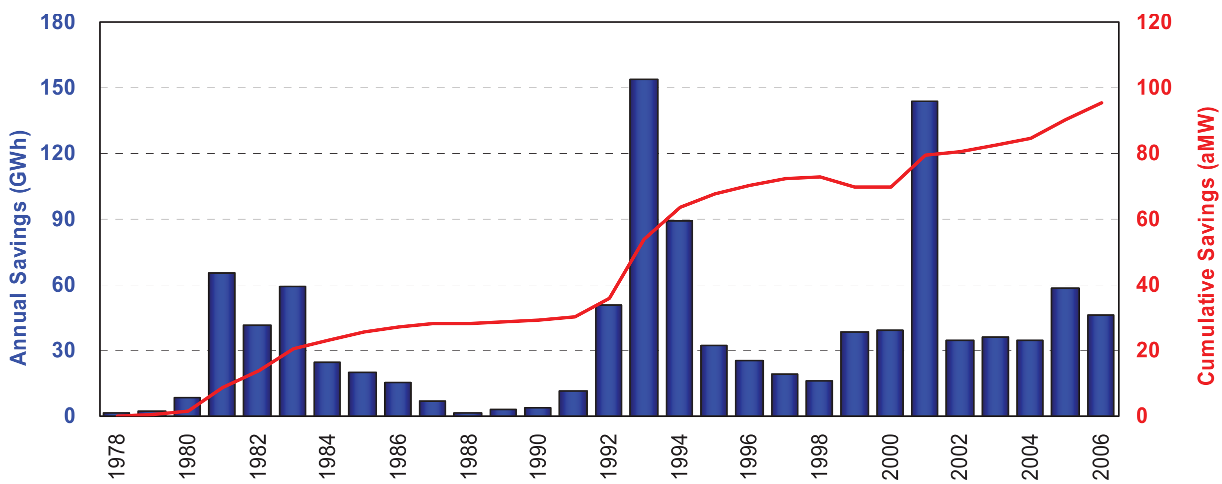
3. DEMAND SIDE MANAGEMENT

A High Efficiency Compact Flourescent Light Bulb

INTRODUCTION

Avista's Demand Side Management (DSM) programs provide a range of energy efficiency options for residential, commercial and industrial customers. They fall into prescriptive and site-specific categories. Prescriptive programs offer cash incentives for standardized products such as compact fluorescent light bulbs and high efficiency appliances. Site-specific programs provide cash incentives for cost-effective energy savings measures with a payback greater than one year. These programs are customized services for commercial and industrial customers because many applications need to be tailored to customer premises and processes. Avista has continuously offered electric efficiency programs since 1978. Some of Avista's most notable efficiency achievements include the Energy Exchanger programs, which converted over 20,000 homes from electric to natural gas for space or water

Figure 3.1: Historical Conservation Acquisition



SECTION HIGHLIGHTS

- Avista has assisted its customers in acquiring cost-effective energy efficiency for 30 years.
- Avista has acquired 124 aMW of electric-efficiency in the past three decades; an estimated 96 aMW is currently online.
- 20,000 customers heat their homes with natural gas today because of the company's fuel-switching programs.
- The company has developed and will maintain the infrastructure necessary to respond quickly in the event another energy crisis occurs.
- The Heritage Project is re-evaluating our traditional programs, updating economic benchmarks, and revising the scope to include transmission, distribution and generation facility efficiencies.

Table 3.1: Current Energy Efficiency Programs

Residential/Limited Income	Commercial/Industrial
High-efficiency natural gas furnaces/boilers	Site specific (any measure)[2]
High-efficiency heat pumps	Efficient lighting and controls
High-efficiency variable speed motors	Food service equipment
High-efficiency and tankless water heaters	Rooftop HVAC maintenance (AirCare Plus)
Electric to natural gas space and water heating	Variable frequency drives
Electric to heat pump	LEED certification
Electric to natural gas water heaters	Premium efficiency motors
Ceiling/attic, floor and wall insulation	Supermarket and warehouse refrigeration
Windows	Power management for computer networks
Limited income measures including health/safety[3]	LED traffic signals
Multi-family, electric to natural gas domestic hot water	Spray head efficiency

heating from 1992-1994; pioneering the country's first system benefit charge for energy efficiency in 1995; and the immediate conservation response during the 2001 Western energy crisis, which tripled annual energy savings at only twice the cost, in half the time, to meet the customer demand for reducing energy usage during a period of high prices. The company's programs provide savings that regularly meet or exceed its regional share of energy efficiency savings as outlined by the Northwest Power Planning and Conservation Council. Historical electricity conservation acquisition is illustrated in Figure 3.1.

During the 30 years that Avista has actively acquired electric efficiency resources, a total of 124 aMW of energy savings has been achieved. We believe that the 96 aMW acquired during the last 18 years is still online and yielding resource value today.[1]

In this IRP planning cycle, all demand-side management (DSM) measures and programs have been examined based on surrogate generation costs. New savings targets have been established, and the company is planning a significant ramp-up of energy efficiency activity. Avista is also expanding the breadth of its efficiency activities to include demand response initiatives and is revisiting the potential for transmission and distribution efficiency measures. These expanded programs are in development and are not reflected in this IRP, but they are included as an action item for the 2009 IRP.

THE HERITAGE PROJECT

The company's new demand response initiative is called the Heritage Project. The Heritage Project focuses on revamping existing energy efficiency targets by applying the best practices within the utility industry. This project continues our legacy of innovation in energy efficiency efforts and customer education. The goal of the Heritage Project is to increase the acquisition of sustainable and cost-effective energy and demand savings through a comprehensive, state-of-the-art demand response initiative. The project examines and implements expanded energy efficiency programs, peak shaving/shifting programs and other options (e.g., distribution system efficiencies).

The Heritage Project focuses on five areas: energy efficiency, load management, transmission and distribution efficiencies, analytics and communications. Each area is supported by analyses and attributes unique to that function.

[1] Cumulative conservation is based upon an 18-year weighted average measure life.
[2] NEEA's website, www.nwalliance.org, offers additional details regarding their ventures, governance, proceedings, reports and evaluations.
[3] It was assumed that historic acquisition would remain flat at the most recent level because there are no reliable 20-year estimates of regional program acquisition. This assumption is speculative and dependent on the opportunities for regional market transformation during this period, but it is consistent with the recent history of flat funding of the NEEA organization.

ENERGY EFFICIENCY

The energy efficiency review evaluated the company's current electric and natural gas efficiency programs to determine what additional programs can be cost-effectively acquired in the near-term (2007) and intermediate term (2008-2010). Avoided costs based on the 2007 IRP, including factors such as risk and capacity, were established to determine the cost-effectiveness of and potential for program expansion. Current delivery mechanisms and outreach efforts were assessed to ensure that all customers have knowledge and adequate opportunities to participate in the company's efficiency programs. Table 3.1 summarizes the DSM programs.

The company's existing efficiency programs are thorough, but several additional opportunities were identified. New programs that are currently under evaluation are outlined in Table 3.2.

REQUEST FOR INFORMATION/REQUEST FOR PROPOSALS

In addition to soliciting internal parties and key stakeholders for concepts to improve the energy efficiency portfolio, the company also released a broad request for information (RFI) in 2006 to obtain the benefit of the opinions outside of our normal range of contacts. The RFI sought ideas for the company to cost-effectively enhance its conservation portfolio through new programs, measures or revisions to existing programs. A total of 53 RFI responses were received. An evaluation of these responses led to two recently released requests for proposals (RFPs) for electric and natural gas efficiency programs within the commercial refrigeration and the residential multi-family housing markets. Four proposals have been received in response to each of these RFPs, and the bids are being evaluated.

LOAD MANAGEMENT

Going forward, peak prices are expected to be significantly higher than prevailing average market prices. For example, the current AURORAxmp model forecast shows average highest day prices between two and three times higher ($80 to $100 per MWh) than average day prices. In addition, the highest prices will be an additional two to three times the average of those prices. This is consistent with recent events in the summer of 2006 where market prices exceeded $200 per MWh. The company does not anticipate that the summer 2006 event will repeat itself frequently, but it remains to be seen whether this was an anomaly or an event that will occur every few years.

With higher peak day prices and additional volatility likely during super critical peak events, demand reduction (DR) measures and distributed generation (DG) has the potential to mitigate cost impacts to customers and utilities.

Table 3.2: Proposed New Energy Efficiency Program[4]

Start Time	Residential and Small Commercial/Industrial	Commercial/Industrial/ Institutional
Q1 2007	Fireplace Dampers	C&I Quick Hits Program
Q2 2007	Super Efficient Habitat for Humanity (HFH) Homes Something For Everyone Measures	Side-Stream Filtration Energy/Heat Recovery Ventilation (ERV/HRV) Demand Control Ventilation (DCV) Steam Traps
Q3 2007	Geographic Saturation Program	Retro-Commissioning Program Behavioral Program
Q4 2007	Regional Natural Gas Market Transformation Program	Facilities Model Program (ongoing)

[4] Due to the accelerated nature of the Heritage Project and the simultaneous IRP evaluation, it was not possible to incorporate all of these measures within the current DSM targets without causing an unnecessary delay in their developement and launch.

Load management opportunities are identified that could be implemented in the near-term (2007) and the medium term (2008-2010). As with the energy efficiency examination, an inventory of all potential load management programs and offerings. The analysis included a review of trade ally data, industry literature, vendor research and a consultant evaluation. The cost of new technologies that enable more precise measurement and control of energy is declining. In order to expedite implementation of these candidate programs the analysis was often performed concurrently with the IRP evaluation, so it was not possible to fully quantify the impacts of these programs within this IRP cycle. This quantification has been identified as an action item for the 2009 IRP.

Five projects, outlined below, have been identified for immediate implementation with a framework established for future activities. This framework evaluates infrastructure needs, system and hardware requirements, costs and benefits, and customer acceptance

Residential Demand Response Pilot – This pilot includes the installation of smart communicating thermostats at specified locations.

Small Commercial Demand Response Pilot – This pilot project includes the installation of wireless dimmable ballasts and/or other technologies in small commercial premises.

Large Commercial/Industrial Interruptibility – Agreements with larger commercial/industrial customers to curtail load during specific events have been successful. This project would expand and formalize the process to include prearranged structured agreements. These agreements could be handled on a buy-back basis in the near-term and on interruptible rate schedules over the long-term.

Avista Facilities Demonstration Project – Avista will test wireless dimming ballasts and other technologies in our own facilities. Other demand response options will be considered and tested, as appropriate.

Large Commercial/Industrial Distributed Generation – In addition to bilateral agreements for curtailment, the company is examining a distributed generation program with selected customers in return for utility-controlled dispatchability.

TRANSMISSION AND DISTRIBUTION

System losses—or lost energy in the form of heat—naturally occur on utility systems in two ways: first, as the power is moved over distances and second, by transfers of electricity through distribution equipment as the power is "stepped-down" from high-voltage to end-user voltages. The company's system losses are estimated to be between 6 percent and 8 percent. Advances in efficient equipment such as improved transformer technology may yield system improvements. Design processes, such as conservation voltage reduction (CVR) and substation engineering and siting, can also provide energy savings on the distribution system.

The company's Transmission and Distribution (T&D) Planning group is examining different ways to economically reduce system losses. The quantification of T&D losses and potential loss reductions is in progress. The cost/benefit relationship will be assessed after the quantification process has been completed. Several projects are underway and pilots are under consideration. Significant time will be required to fully evaluate the results of the near-term potential projects and to ascertain potential resource opportunities. It is premature to incorporate these efforts into the IRP targets, so they have been identified as an action item for the 2009 IRP.

ANALYTICS

The identification of the cost-effectiveness of alternative supply resources and appropriate cost-recovery depends upon an analytical approach that is technically sound and transparent. Several departments collaboratively developed an analytical process to determine overall resource values of energy and capacity. Resource valuation for the Heritage Project is based upon seven categories: five categories are reflected in a total avoided cost of energy usage and the other two are based upon system-coincident demand reductions.

Analytical values contributing to an overall resource value of energy include the avoided cost of energy and carbon emissions, reduced volatility, reduced transmission and distribution system losses. Analytical values contributing to overall avoided costs of system-coincident capacity include the value of deferring capital investments for generation and transmission and distribution. A summary of these calculations has been provided in the Appendices.

COMMUNICATIONS PLANNING

Communicating the availability of conservation programs is critical to achieving energy savings. The Heritage Project is developing a sustained outreach campaign. This plan is staged for new program roll-outs and is tailored to select the optimal tool for communicating each program. This focus includes communications to all Avista employees, as well as enhanced training for employees with customer contact.

COOPERATIVE REGIONAL MARKET TRANSFORMATION PROGRAMS

Avista is a funding and fully participating member of the Northwest Energy Efficiency Alliance (NEEA).[5] NEEA is funded by investor-owned and public utilities throughout the Northwest to acquire electric efficiency measures that are best achieved through market transformation efforts. These efforts reach beyond individual service territories and consequently require regional cooperation to succeed.

NEEA has proven to be a cost-effective component of regional resource acquisition. Avista has and will continue to leverage NEEA ventures when cost-effective enhancements to the programs can be achieved for our customers.

Attributing regionally acquired resources to individual utilities is difficult. In order to ensure that resources are not double-counted at both regional and local levels, NEEA has excluded from their claims all energy for which local utility rebates have been granted. Therefore it is correct to sum the local and regional acquisition to obtain the total impact within the effected markets. Avista has typically applied our funding share of slightly less than 4 percent to NEEA's annual claim of energy savings.

DSM PROGRAM FUNDING

As previously noted, in 1995 the company changed its approach to cost-recovery of DSM investments from the traditional capitalization of the investments to cost-recovery through a non-bypassable public benefits surcharge (the DSM tariff rider). The company currently manages four separate DSM tariff riders for Washington electric, Idaho electric, Washington natural gas and Idaho natural gas investments. Based upon the demand for funds and incoming DSM tariff rider revenues, this balance can be positive or negative at any particular point in time.

In 2005 the aggregate DSM tariff rider balance was returned to zero from a $12.4 million deficit in the aftermath of the 2001 Western energy crisis. Recent demand for DSM services has outstripped the incoming DSM tariff rider revenue. The most recent projection

[5] NEEA's website, www.nwalliance.org, offers additional details regarding their ventures, governance, proceedings, reports and evaluations.

forecasts a $3.8 million negative balance in the Washington electric DSM tariff rider at the close of 2007. The Idaho electric DSM balance is projected to be close to zero at that time.

The company has proposed the capitalization of electric DSM investments in Washington. The proposal would continue the current tariff rider mechanism, with the revenues generated from the tariff rider funding the revenue requirement of the DSM investments.

Additionally there is a proposal for the recovery of lost electric margin (or fixed cost recovery) associated with the company's DSM efforts. Both of these proposals have been advanced to provide a more level playing field for demand and supply-side resource investments.

At present the company is not compensated for the fixed costs associated with reductions in load resulting from electric DSM achievements. The company submitted a proposal to the Washington Utilities and Transportation Commission for fixed cost recovery between general rate cases.

OVERVIEW OF ELECTRIC-EFFICIENCY IN THE 2007 IRP

The implementation of the Heritage Project began in the midst of the 2007 IRP evaluation. Some, but not all, of the Heritage Project initiatives have been incorporated in this version. The 2009 IRP cycle will fully explore some of the details and resulting efforts.

CONSISTENCY BETWEEN THE IRP EVALUATION AND DSM OPERATIONS

For each IRP, the company evaluates energy-efficiency potential in a manner that can augment the conservation business planning process and ultimately lead to appropriate revisions in DSM acquisition operations.

Avista has utilized the IRP process as an opportunity to comprehensively re-evaluate the market. This assessment evaluates individual technologies (generally prescriptive programs) where possible and program potential when a technology approach is infeasible. The evaluation is based upon an assessment of resource characteristics and the construction of a conservation supply curve based upon the levelized total resource cost (TRC) and acquirable resource potential for each technology. Cost-effective technologies, compared to the defined avoided cost, are incorporated into the IRP acquisition target.

The program evaluation is necessary when technologies in the program cannot be defined to permit their individual evaluation. This is the case in the company's comprehensive limited income and non-residential programs.[6] The target acquisition for these programs is based upon modifying the historical baseline for known or likely changes in the market. This includes but is not necessarily limited to modifying the baseline for price elasticity and load growth.[7]

EVALUATION OF EFFICIENCY TECHNOLOGY OPPORTUNITIES

Avista initiated an internal review of the company's response to the July 24, 2006, heat wave and short-term escalation of regional wholesale electric prices. An exploration of possible future responses to short-term price spikes and other longer term approaches to reduce the impact of market volatility was a key component of that process. Approximately 140 concepts came out of a series of meetings attended by a cross-section of the company.

[6] It was assumed that historic acquisition would remain flat at the most recent level because there are no reliable 20-year estimates of regional program acquisition. This assumption is speculative and dependent on the opportunities for regional market transformation during this period, but is consistent with the recent history of flat funding of the NEEA organization.
[7] The portions of the non-residential market that could be identified and evaluated based upon technology applications were included in that portion of the study. These components were excluded from the historical baseline for the remaining non-residential technologies evaluated under programmatically.

Avista's DSM analysis staff and Navigant Consulting performed a six-stage review of this concept list. The process first evaluated concepts with easily obtained data and gradually moved toward the more difficult analyses. Some measures did not rank well enough to warrant further consideration. The individual phases of the analytical process follow:

Defining: Refinement and redefinition of the concept list eliminated duplicative concepts and allowed an opportunity to develop common definitions for each concept.

Qualitative ranking: The more clearly defined concepts from the prior phase were ranked on a qualitative assessment of feasibility. Opportunities which were clearly not acquirable by utility intervention were eliminated from further consideration.

Defining cost characteristics: Those concepts that were determined to have a reasonable potential for eventual incorporation into the conservation portfolio were evaluated on preliminary assessments of cost-effectiveness. This step required obtaining estimates of incremental customer cost, non-energy benefits, energy savings and measure life to develop a TRC levelized cost. Concepts were sorted based upon these cost characteristics.

Defining resource potential: Acquirable potentials specific to the Avista service territory were estimated for the remaining concepts. These acquirable potentials were the result of an assessment of technical and economic potential tempered by the realization that utility intervention cannot successfully address all customer adoption barriers regardless of the economics. The acquirable resource potential for some technologies has been modified, generally upward, as a result of Heritage Project.

Developing load profiles: This IRP evaluation is the first time that Avista has specifically incorporated the value of capacity contribution (transmission, distribution and generation) into the overall avoided cost. Additionally the company is basing the avoided cost of energy upon a 20-year, 8760-hour avoided cost matrix. It was necessary to extrapolate the 20-year avoided cost projection to 40 years given the longevity of some of the measures. As a consequence of this avoided cost structure it was necessary to develop an 8760-hour load profile for each measure to be evaluated. Navigant Consulting Group provided 22 residential and non-residential load profiles for use in this part of the exercise.[8]

Calculating TRC cost-effectiveness: A full TRC cost-effectiveness evaluation was performed upon the remaining 39 residential and 36 non-residential concepts.[9] Four concepts were removed from this list due to questions regarding the viability of the data obtained in earlier stages or the discovery of previously undetected fatal flaws to the program. The following section provides a more detailed evaluation of the review and acceptance or rejection of these concepts.

A summary list of the concepts reaching the evaluation stage is included in the Appendices.

EVALUATION OF TRC COST-EFFECTIVENESS FOR FINALIST CONCEPTS

The construction of the TRC cost for each measure was based upon the incremental customer cost. Non-energy benefits were considered, but none of the evaluated measures had a large enough non-energy benefit to

[8] See the Appendices for a list of these load profiles.
[9] Three residential and one non-residential concept were subsequently excluded due to concerns over the validity of key resource characteristic assumptions.

materially change the final cost-effectiveness evaluation.[10]

Estimating the TRC values was more difficult. This required a present value calculation of the avoided energy and capacity cost over the measure life. The avoided cost of energy was based upon an application of the measures 8760-hour load profile to the 8760-hour avoided cost structure. Five energy and two capacity avoided cost values developed within the Heritage Project Analytical Roadmap were applied to the load shapes of each measure concept.[11]

The valuation of capacity based upon these load shapes and capacity avoided cost values had never been incorporated into the evaluation of DSM opportunities at Avista. The per kW present values for T&D and generation capacity estimated in the Analytical Roadmap were based upon a single fixed period of time. Escalating streams of annual values that were consistent with the values within the Analytical Roadmap allowed for the development of capacity values for varying measures lives. The details of this calculation are contained within the Appendices.

The consensus of opinion held that, for purposes of the evaluation of DSM measures, it was appropriate to focus upon deferring a summer space-cooling-driven load. The 71 concepts to be evaluated had significant differences in their impact upon system coincident load, and these differences were not always apparent based upon the general pattern of the measure load shape. To determine the expected impact upon the deemed space cooling-driven system peak load, the 71 concepts and 23 load shapes (including a flat load option) were categorized into three groups.

Zero impact: Measures that would not have any impact on a summer space-cooling-driven peak received a zero valuation regardless of their load profile. This would include measures such as residential space-heating efficiencies.

Non-Drivers: Measures that were not related to space cooling but would potentially contribute to system load during a space cooling-driven peak received a capacity valuation based upon the average demand of their specific load profile during eight hour summer peak load periods.[12] These measures include commercial lighting, residential appliances and so on.

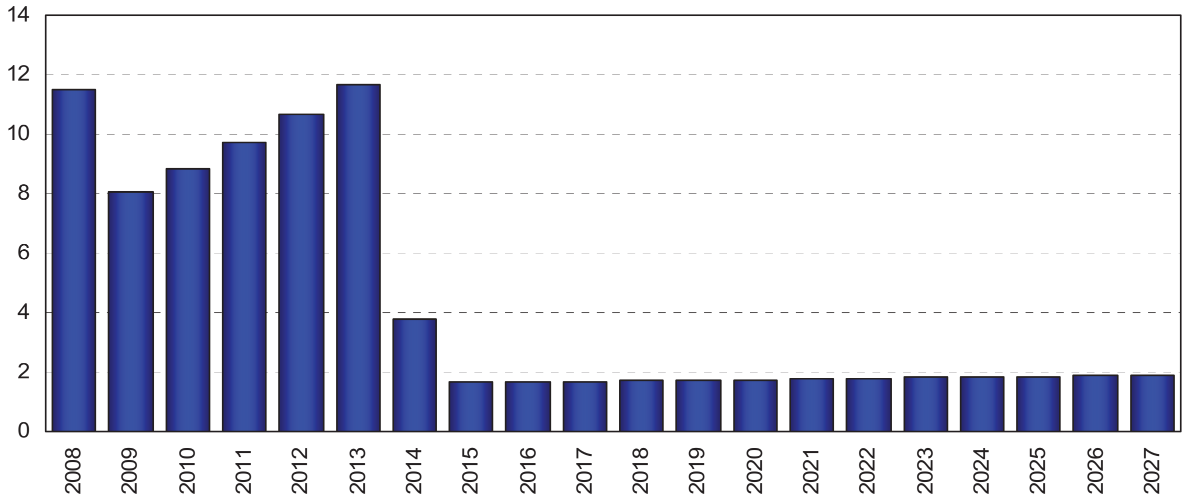
Drivers: Those measures that would drive a space cooling peak received a capacity valuation based upon the maximum hourly demand identified in their 8760-hour load profile. This would include measures such as residential and non-residential air conditioning efficiency measures.

Once the TRC cost and benefit calculations were completed, a TRC ratio was developed. Even though this analysis limits the identification of future DSM acquisition to measures that fully pass the TRC cost-effectiveness test, the company plans on evaluating all measures with a benefit-to-cost ratio of 0.75 or higher.

Having identified TRC cost-effective measures it was necessary to determine the annual acquisition of the identified potential. Inspection of the results to date indicated that there was clearly more potential than identified in the 2005 IRP process (5.4 aMW, excluding regional acquisition efforts, or 47.5 million first-year kWh). Thus the acquisition of the potential conservation requires a ramping-up of DSM operations, which is being done through the Heritage Project. A ramp

[10] The non-energy benefit, or cost, could have been represented as a TRC cost or benefit as long as the appropriate sign was used in the evaluation without impacting the ultimate passing or failing of the measure.
[11] The specific components of the avoided cost are summarized in the Appendices.
[12] The eight peak hours were 1 p.m. to 8 p.m., weekdays only, between June 15 and September 15.

Figure 3.2: Year-On-Year Conservation Acquisition (%)



rate was developed based upon the sales cycle of the customer decisions and the speed at which programs could be developed, incorporated into trade ally efforts and communicated to the customer base. This ramp rate is represented graphically in Figure 3.2 and outlined in more detail in the Appendices.

This completed the evaluation of those concepts that were suitable for review by technology within the IRP. These results are revisited following the explanation of the programmatically reviewed elements of the DSM portfolio.

EVALUATION OF COMPREHENSIVE PROGRAM ELEMENTS

As a consequence of the all-inclusive nature of Avista's non-residential and limited income portfolio, it was not feasible to generically evaluate all possible efficiency measures. Nevertheless it is necessary to develop an estimate of the potential of these markets in order to establish a meaningful business planning process. Unique efficiency measures could not be generically evaluated as individual technologies. In place of this approach the company established a historical baseline level of acquisition and modified it to incorporate the impact of known or likely changes in the market.

The company's limited income portfolio of qualifying efficiency measures is all-inclusive. It is implemented in cooperation with community action agencies given wide latitude in their approaches. Given that no changes were expected in the ability of the agency infrastructure to deliver these programs, nor were there any known market or technology changes that would cause a significant change in the ability to obtain efficiency resources from this segment, it was determined that a historical baseline would be the most appropriate starting point for estimating future throughput. This historical baseline was modified for load growth and retail price elasticity based upon assumptions consistent with the forecasts available at the time. This resulted in a forecast of limited income acquisition for incorporation into the final conservation forecast.

Although some of the measures incorporated into the site-specific program were specifically evaluated, a large portion of non-residential acquisition comes from measures which could not be generically evaluated. As with the limited income program, the historical baseline was modified for anticipated load growth and retail price elasticity to develop a forecast. Unlike the limited income program, it was necessary to separate the specifically evaluated measures from the historical baseline, and then combine the two again as part of the final expected conservation acquisition.

This process is illustrated in a flowchart in the Appendices.

COMPILATION OF THE FINAL DSM RESOURCE ESTIMATES

The following conservation targets were developed by summing individually evaluated concepts and the evaluated programs over a 20-year period. The first two years of those targets are detailed in Table 3.3.[13]

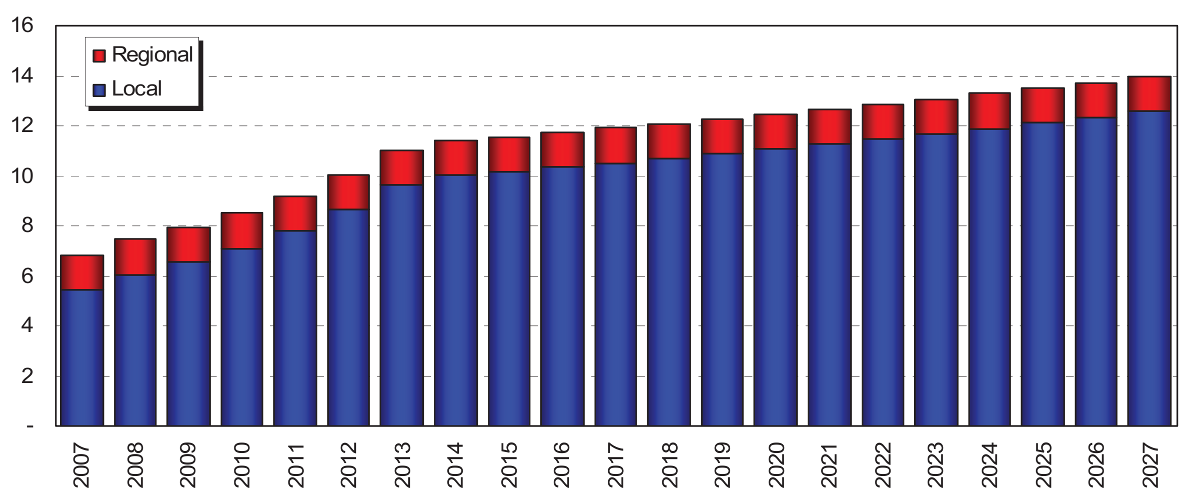
A graphical representation of the annual conservation targets for the full 20-year horizon is illustrated in Figure 3.3. A flat 1.4 aMW estimate of Avista's share of regional resource acquisition (Avista's pro-rated share of NEEA's annual savings) is included in the estimate.[14]

A measure-by-measure stacking of the 71 evaluated concepts, in ascending order of levelized total resource cost, leads to a traditional upward-sloping supply curve for this component of the energy efficiency target, as illustrated in Figure 3.4. Supply curves for both 2008 and 2009 have been shown to represent the two years

Table 3.3: Current Avista Energy Efficiency Programs (kWh)

Portfolio	2008 Target	2009 Target
Limited Income Residential	1,562,956	1,594,215
Residential	10,939,762	13,674,702
Prescriptive Non-Residential	1,279,711	1,599,639
Site-Specific Non-Residential	39,184,260	40,359,787
Total Local Acquisition	**52,966,686**	**57,228,343**

Figure 3.3: Forecast of Efficiency Acquisition (aMW)



[13] This application of price elasticity is consistent with but not incorporated within forecast assumptions since the efficiency savings quantified through the company's DSM programs are limited to those which are in excess of the higher of code-minimum or industry standard practice.

[14] In the absence of reliable 20-year estimates of acquisition through regional programs, it was assumed that the historic acquisition would remain flat during that time at their most recent level. This assumption is speculative and dependent on the opportunities for regional market transformation during this period but is consistent with the recent history of flat funding of NEEA.

Figure 3.4: Supply of Evaluated Efficiency Measures

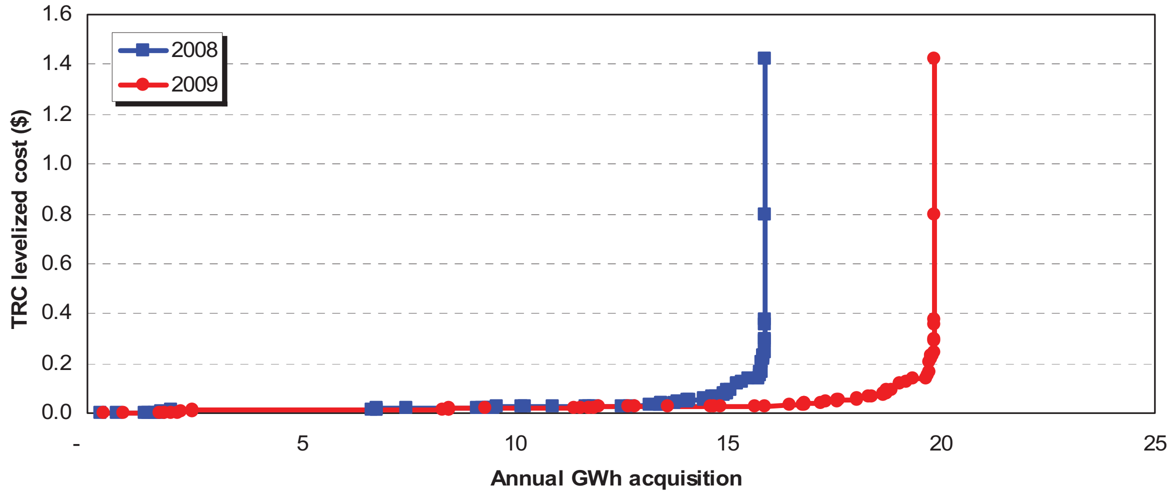
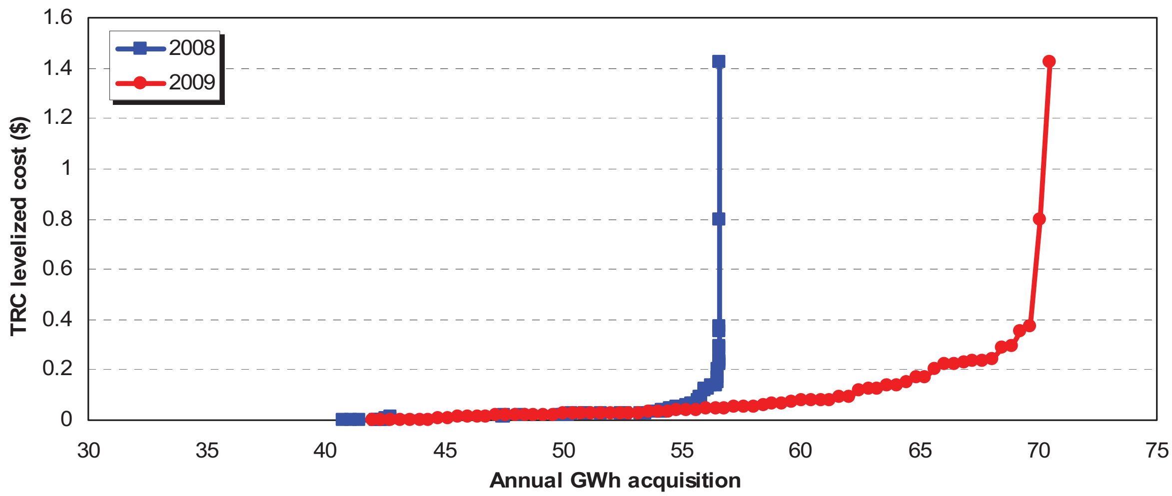


Figure 3.5: Efficiency Supply Curves Including All Measures



which will elapse before the next IRP. The rightward shift of the supply curve over time is a consequence of the assumptions made in the ramping-up of these programs.

The rapid sloping of the supply curve tails are the result of including a few measures that were later determined to be far more costly than previously anticipated.[15] These programs, though small, significantly extended the vertical axis of the supply curve developed for the efficiency measures.

By adding the target for programmatically-evaluated energy efficiency efforts to the left portion of the supply curve, a full assessment of the estimated efficiency targets can be illustrated. This is shown in Figure 3.5.

INTEGRATING IRP RESULTS INTO THE BUSINESS PLANNING PROCESS

The IRP evaluation process provides a high-level estimate of cost-effective energy efficiency acquisition. Based upon these results the company can establish a budget, determine the size and skill sets necessary for

[15] These two measures were residential induction cook tops and non-residential demand-controlled ventilation. The measures exceeded a levelized TRC cost of approximately 80 cents per kWh. Four other measures exceeded levelized TRC costs of 25 cents per kWh: non-residential window films, non-residential light colored roofs, residential smart appliances and non-residential Energy Star office equipment.

future conservation operations and identify general target markets.

The results of the IRP analysis will establish baseline goals for the ongoing development of the Heritage Project's enhancements to Avista's energy efficiency programs. The near-term planning is summarized by portfolio in the following sections.

RESIDENTIAL PORTFOLIO

A review of residential concepts and their sensitivity to key assumptions indicate that more detailed assumptions based upon actual program plans and target markets may improve the cost-effectiveness of many concepts that marginally failed in this analysis. To account for this marginal failure rate, all concepts with TRC benefit-to-cost ratios of 0.75 or better will be evaluated as part of the business planning process. Twenty-seven of the 36 evaluated residential concepts meet this criterion.

Measures that were developed too late for the IRP evaluation will also be inserted into this re-evaluation process. One of the recent additions, top-mounted fireplace dampers, has completed the program planning and evaluation process and was launched prior to the completion of this IRP.

LIMITED INCOME RESIDENTIAL PORTFOLIO

Avista has committed to maintaining stable annual funding and program flexibility for the six community action agencies delivering limited income energy efficiency implementation services. The flexibility of these programs requires periodic updates to program expectations due to changes in fuel focus and target measures. The company will also be working to quantify the future potential impacts of the three-year Northwest Sustainable Energy for Economic Development project.

NON-RESIDENTIAL PORTFOLIO

Similar to the residential program, it was determined that there is potential for improvement in evaluated program concepts to warrant the re-evaluation of any measure determined to have a TRC cost-to-benefit ratio of 0.75 or better. Of the 35 fully evaluated non-residential concepts, 25 of these meet the TRC criteria. These programs will be reviewed for target marketing, the creation of a prescriptive program or for targeting under the site-specific program.

All electric-efficiency measures qualify for the non-residential portfolio. The IRP provides account executives, program managers and end-use engineers with information regarding potentially cost-effective target markets, but specific characteristics of customers' facilities override any high-level program prioritization.

UNDERLYING RESOURCE ACQUISITION COMMITMENT

The IRP evaluation process is both a business planning process and regulatory requirement. The company uses this opportunity for comprehensive evaluation as a part of the management of the company's energy efficiency portfolio. The acquisition targets provide valuable information for future budgetary, staffing and resource planning needs. However, numerical targets do not displace the company's fundamental obligation to pursue a resource strategy that best meets the customer needs under continually changing environments. The targets established within this IRP planning process may be modified as necessary to meet these obligations.

SUPPLY SIDE EFFICIENCY

Avista also actively works on improving efficiency of its generation fleet. The following section highlights planned and potential hydroelectric efficiency upgrades. Recent thermal upgrades to the Colstrip plants are detailed in chapter two.

NOXON RAPIDS

The company plans to upgrade Noxon Rapids units

1-4 beginning in March 2009. The current maximum capability at Noxon Rapids is 554 MW; however, operating restrictions limit the plant to 532 MW. The upgrades will eliminate the operating restrictions and add an additional 16 MW to the project, increasing the plant capability to 570 MW and add 5.8 aMW of energy.

NINE MILE

The company currently uses flashboards at its Nine Mile plant to increase water storage during the fall and winter months. The flashboards are released downstream during spring runoff when the reservoir level must be lowered to accommodate the increased flow of water. The flashboards are re-installed every summer. The company is considering replacing the flashboards with a permanent pneumatic rubber dam which would automatically adjust the reservoir level to the flow rate, increasing the reservoir level when flow is low and decreasing the level when flows increase. The rubber dam would stabilize the Nine Mile project as well as eliminate the need to purchase and reinstall flashboards each year. This project would increase annual generation by about 6,500 MWh. Also two of the four generators at the Nine Mile project require repair or replacement in the near future. The company is studying the replacement of these units in-kind or replacing with larger units to increase the maximum capacity and maximum flow at the project.

UPPER FALLS

The Upper Falls project, located in downtown Spokane, has one generating unit. The company is currently studying the advantages of upgrading the turbine runner and refurbishing other generator components.

LITTLE FALLS

Turbine runners at two of the four generators at Little Falls have recently been replaced. The company is studying the benefits of replacing the turbine runners in the remaining units. Other potential projects include replacing the step-up transformers and upgrading other generator components.

A summary of the various hydro efficiency studies is shown in Table 3.4.

Table 3.4: Recent Hydro Efficiency Upgrade Studies

Project	Potential Additional Annual Energy (MWh)	Potential Additional Annual Energy (aMW)	Potential Additional Capacity (MW)	Total Project Capacity (MW)
Noxon Rapids	50,808	5.80	16.0	570.0
Nine Mile				
Rubber Dam	6,500	0.74	-	26.4
Turbine Upgrades	87,000	9.93	8.0	34.4
Upper Falls	63,000	7.19	6.4	15.0
Little Falls	52,000	5.94	8.0	44.1

4. ENVIRONMENTAL ISSUES

Environmental issues cover a wide variety of topics. To keep the concepts manageable, this chapter highlights some of the more important environmental issues affecting resource planning, the most notable being thermal plant emissions. The chapter is not intended to debate the merits or weaknesses of environmental science or the effects of power generation emissions. Instead, it covers state and federal laws and pending legislation affecting sulfur dioxide (SO_2), nitrogen oxide (NO_x), mercury (Hg), and carbon dioxide (CO_2) emissions. The modeling assumptions used for each emission types are explained. Particular attention is paid to greenhouse gases (GHG) because their regulatory future is the most uncertain and has the potential to affect resource decisions most significantly.

ENVIRONMENTAL CHALLENGES

Emissions present a unique challenge for resource planning because of continuously evolving scientific understanding and legislative developments. If environmental concerns were the only issue faced by utilities, resource planning would be reduced to choosing the amount and type of renewable generating technology to use. However, utility planning is compounded by requiring cost effectiveness. Each type of generating resource has distinctive operating characteristics, cost structures, and environmental challenges. Traditional generation technologies are well understood. Coal-fired units have high capital costs, long lead times, and low and stable fuel costs. Coal plants are difficult to site and are affected by a host of environmental issues from Hg to

Sheep Grazing Near a Wind Farm in Washington State

CHAPTER HIGHLIGHTS

- The company includes greenhouse gas emissions costs in its Base Case.
- Avista relies on its Climate Change Committee to develop climate change policy and mitigation plans.
- SO_2, NO_x, Hg, and CO_2 emissions costs are included in the modeling for the 2007 IRP.
- Avista supports national greenhouse gas legislation that is workable, cost effective, fair, protects the economy, supports technological innovation and addresses emissions from developing nations.
- Avista is a member of the Clean Energy Group.

GHG. Natural gas-fired plants have relatively low capital costs and more acceptable emission levels but rely on fuel that has proven to be both high in price and price volatility. Renewable energy plants, including wind, biomass and solar, have different problems to contend with. Renewables benefit from potential low or no fuel costs and low or no emissions, but they are plagued by capacity problems, wildlife issues, high capital costs, uncertainty regarding production tax credits and an increasing number of siting issues.

The most uncertain aspect of emissions is future GHG legislation. There recently has been a tremendous upsurge in the amount of scientific, public and legislative attention regarding climate change. There are five main aspects to consider with climate change: scientific, public, government, legal and financial. The scientific community has shown increasing evidence of human involvement in global warming, culminating with the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report, which was released in February 2007. This report stated that there is a greater than 90 percent chance that global warming is the result of human intervention through greenhouse gas emissions. The public is becoming increasingly aware of climate change issues and is pressing for governmental and corporate action. Legislatively, there are increasing numbers of local, state, regional, and federal GHG initiatives, renewable portfolio standards and emissions standards. On the legal front there are issues of state versus federal jurisdiction, project-specific pressures and attempts at class action lawsuits. Examples of legal issues include the April 2, 2007, U.S. Supreme Court decision that the Environmental Protection Agency had a duty to regulate greenhouse gases; the environmentally-pressured decisions in the leveraged buyout case of TXU not to build eight new coal plants; and the climate change lawsuits filed against utilities, auto makers and oil companies in the wake of hurricanes along the Gulf Coast. Financially, there are potential compliance costs, increasing demand for renewable resources driving up prices and shareholder pressure regarding climate change issues.

AVISTA'S ENVIRONMENTAL INITIATIVES AND POLICIES

One of the 2005 IRP action items was to "continue to monitor emissions legislation and its potential effects on markets and the company." This action item has received significant attention throughout the company over the past two years which resulted in an interdepartmental meeting on June 8, 2006, to cover climate change topics including: Congress and climate change, Avista's GHG inventory, Coyote Springs 2 emissions offsets, emissions assumptions included in the IRP and state commissions' guidance on climate change. After this meeting, a core group of employees from Environmental Affairs, Governmental Affairs and Resource Planning began meeting regularly to discuss current climate change information and legislative activities affecting the company. This group also reviewed climate change policies from other organizations, worked on drafting Avista's climate change statement and developed educational pieces.

The core group met with the company's Strategic Planning Council in March 2007 to discuss current climate change activities and developments. This meeting resulted in the appointment of an officer to spearhead the formalization of Avista's Climate Change Council (CCC). The CCC has been chartered to be a clearinghouse on all matters related to climate change. The CCC:

- anticipates and evaluates strategic needs and opportunities;
- analyzes the implications of various trends and proposals;
- develops recommendations on company positions and action plans; and
- facilitates internal and external communications.

The core team of the CCC includes members from the Environmental Affairs, Government Relations, Corporate Communications, Engineering, Energy Solutions and Resource Planning departments. Other areas of the company are invited as needed.

Monthly meetings divide work into immediate and long-term concerns. Immediate concerns include reviewing and analyzing state and federal legislation, developing a corporate climate change policy and responding to external data requests regarding climate change issues. Longer term issues involve emissions tracking and certification, reviewing alternatives and providing recommendations for GHG reduction goals and activities, evaluating the merits of joining various GHG reduction programs, actively participating in the development of GHG legislation, and benchmarking climate change policies and activities with other organizations.

Avista recently joined the Clean Energy Group which includes Calpine, Entergy, Exelon, Florida Power and Light, PG&E and Public Service Energy Group. This group acts collectively to evaluate and support different GHG legislation such as the Clean Air Planning Act of 2007 sponsored by Tom Carper (D-DE). This legislation seeks to establish multi-pollutant limits using a market-based approach to "reducing power plant emissions of nitrogen oxides, sulfur dioxide, mercury and carbon dioxide."

AVISTA'S POSITION ON CLIMATE CHANGE LEGISLATION

The company expects federal greenhouse gas legislation to be enacted within the next two to four years. The absence of definitive legislation on climate change creates an uncertain environment as the company develops its plans for meeting future customer loads. Avista does not have a preferred form of GHG legislation at this time. However, the company supports federal legislation that:

- anticipates and evaluates the strategic needs and opportunities;
- is workable and cost effective;
- is fair;
- is protective of the economy;
- is supportive of technological innovation; and
- is inclusive of emissions from developing nations.

Workable and cost effective legislation would be carefully crafted to produce actual emission reductions through a single system, as opposed to competing state, regional and federal systems. The legislation also needs to be fair in that it is equitably distributed across all sectors of the economy based on relative contribution to GHG emissions. Protecting the economy is of utmost importance. The legislation cannot be so onerous that it stalls the economy or fails to have any sort of adjustment mechanism in case the market solution fails and prices skyrocket. Supporting a wide variety of technological innovations should be a key component of any GHG reduction legislation because innovation can help maintain costs, as well as provide a potential boost to the economy through an increased manufacturing base. The final piece to the legislative solution to climate change involves developing nations. China will soon overtake the U.S. as the leading source of GHG emissions. Legislation should include strategies for working with other nations directly or through international bodies to control world-wide emissions.

EMISSIONS CONCERNS FOR RESOURCE PLANNING

The main emissions concerns for resource planning involve balancing environmental stewardship and cost effectiveness, and mitigating the financial impact of emissions risks. The 2007 IRP focuses on four types of emissions that are significant to electric generation: SO_2, NO_x, Hg, and CO_2. Sulfur dioxide is a cause of acid rain; the Clean Air Act of 1990 capped its emissions at 8.9 million tons per year starting in 2008. This pollutant is actively regulated through a cap-and-trade program. Nitrogen oxide is also regulated by the Clean Air Act of 1990 at 2.0 million tons per year starting in 2008. Mercury is an emission with planned regulation by the federal government under a cap-and-trade program. However, many states are opting out of that program. Carbon dioxide is a primary greenhouse gas. It is beginning to be regulated in some states and is the focus of federal legislation.

EMISSIONS LEGISLATION

There are several themes that emerge from all of the recently developed climate change legislation. These include:

- Scientific questions about human contributions to climate change – is it an anthropogenic or human-developed phenomenon need to be settled;
- Actions need to be economy-wide, rather than one or two sectors at a time;
- Technology will be a key component to the climate change solution. There will most likely need to be significant investments in carbon capture and sequestration technology, since coal likely will continue to be an important part of the U.S. generation fleet;
- Developing countries should be engaged as developing nations to expand their economies and carbon footprints; and
- Long delays in federal legislation increase the probability of a menagerie of inconsistent regulatory schemes that may obstruct the efficient operation of regional or national businesses.

These themes point to national comprehensive GHG legislation implemented in a timely manner to ensure the best environmental and fiscal outcomes.

FEDERAL EMISSIONS LEGISLATION

The federal government is currently reviewing at least six different market-based programs to reduce greenhouse gas emissions. This is the culmination of many previously failed attempts at national legislation, the most significant being the McCain-Lieberman Climate Stewardship Act submitted to Congress in January 2003 and annually thereafter. Most legislation relies on a market-based cap-and-trade system in an attempt to emulate the success of the national acid rain program. There are many questions that still need to be resolved before national GHG legislation can be enacted. These include:

- the allocation of allowances – emissions or generation-based;
- economy-wide or sector specific;
- offsets;
- incentives for early action;
- economic safety valves;
- up or downstream regulation; and
- cap-and-trade or tax.

There are indications from Congress that federal legislation will be passed in 2007, but great uncertainty still remains over the specifics of the legislation or when it will be passed into law. The company believes that some form of market-based GHG legislation is inevitable and includes it in its Base Case IRP assumptions. The company introduces CO_2 emission charges in 2015. Recent developments in GHG legislation lean toward an earlier start date, but 2007 IRP modeling was substantially complete before recent Congressional activity began. Upon review of the modeling results, the company does not believe that adding charges sooner would in any way impact its Preferred Resource Strategy.

STATE LEVEL EMISSIONS LEGISLATION

Federal inaction on climate change has spurred many states to develop their own laws and regulations. Climate change legislation has taken many forms, including GHG emissions caps, renewable portfolio standards (RPS) and mandated efficiency levels. A patchwork of competing rules and regulations has sprung up for utilities to follow, making resource planning for utilities with multi-jurisdictional responsibilities like Avista more difficult. Currently there are 23 states and the District of Columbia with active renewable portfolio standards. California, Connecticut, North Carolina and Rhode Island are working on legislation to phase out the use of incandescent light bulbs.

Some of the more notable state-level GHG initiatives outside of the Pacific Northwest include the Regional Greenhouse Gas Initiative (RGGI): an agreement between 10 Northeastern states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont) to develop a cap-and-trade program for power plant CO_2 emissions. The District of Columbia, Pennsylvania and some Canadian Provinces are participating as observers in the RGGI process.

The Western Regional Climate Action Initiative was developed from a Feb. 26, 2007, agreement between Washington, Oregon, California, New Mexico, Arizona and British Columbia to reduce GHG emissions through regional reduction goals and the establishment of a market-based trading system. There are a number of regional municipalities participating in the U.S. Mayors Climate Protection Agreement to reduce GHG emissions to 93 percent of 1990 levels by 2012.

Nationally the Clean Air Mercury Rule (CAMR) established permanent caps to reduce mercury reduction from coal-fired power plant emissions. CAMR allows states to participate in a nation-wide mercury trading allowance program. States are allowed to determine if their national allocations are distributed among existing emitters, auctioned or some combination of the two methods.

IDAHO EMISSIONS LEGISLATION

Idaho does not actively regulate greenhouse gases or set renewable portfolio standards for its electric utilities. Idaho governor Butch Otter issued an executive order in May 2007 directing the Idaho Department of Environmental Quality (IDEQ) to work on "a policy on the role of state government in reducing greenhouse gases." The IDEQ is to develop a GHG emissions inventory and reduction strategy. Idaho has demonstrated concerns with coal-fired power plants; most notably, HB 791 (2006) established a moratorium on new merchant coal-fired power plants for a two-year period. The state has decided to opt out of CAMR, meaning that a plant located in Idaho could not purchase mercury credits to offset its emissions. By opting out of CAMR, the state has effectively stopped coal plant development.

MONTANA EMISSIONS LEGISLATION

The Montana Global Warming Solutions Act (HB753) was submitted in late 2006 to establish greenhouse gas reductions goals through 2020. The legislation did not make it out of committee. Montana limits mercury emissions to 0.9 pounds per decatherm for plants using sub-bituminous coal, and 1.5 pounds for lignite-fired plants. Montana requires 15 percent of all electricity to come from new renewables by 2015.

OREGON EMISSIONS LEGISLATION

Oregon has been actively developing greenhouse gas, renewable portfolio standards and mercury emission legislation. Oregon's climate change legislation goes back to its December 2004 Oregon Strategy for Greenhouse Gas Reduction. It called for development of a detailed GHG report by the end of 2007 and for stabilization of all six GHGs by 2010, a 10 percent reduction from 1990 levels by 2020 and a 75 percent reduction from 1990 levels by 2050. The goals are in addition to the 1997 regulation requiring utilities to offset CO_2 emissions exceeding 83 percent of the emission level of a state-of-the-art gas-fired CCCT. State Senate Bill 838 requires large electric utilities to generate 25 percent of annual electricity sales with new renewable resources by 2025.

Shorter term renewable goals include 5 percent by 2011, 15 percent by 2015, and 20 percent by 2020. Oregon has set mercury emissions levels equaling 90 percent reduction or 0.60 pounds per Dth by July 1, 2012, with some allowances for compliance alternatives if the targets cannot be met using best available emissions controls.

WASHINGTON EMISSIONS LEGISLATION

Washington State is quite active on global warming and renewable energy issues, recently passing an RPS initiative and GHG legislation. This is in addition to a 2004 law requiring new fossil-fueled thermal electric generating facilities of more that 25 MW to have a CO_2 mitigation plan of third-party offsets, purchased carbon credits or cogeneration.

The Washington Clean Energy Initiative (I-937) passed in the November 2006 election. This initiative established an RPS for Washington equal to 3 percent of retail load by 2012, 9 percent by 2016, and 15 percent by 2020. The 2007 IRP has been developed so that the I-937 RPS goals will be achieved by the company for its Washington retail load.

Governor Christine Gregoire signed Executive Order 07-02 in February 2007, establishing the following GHG emissions goals:

- return to 1990 levels by 2020;
- 25 percent below 1990 levels by 2035;
- 50 percent below 1990 levels by 2050, or 75 percent below expected emissions in 2050;
- increase clean energy jobs to 25,000 by 2020; and
- reduce statewide fuel imports by 20 percent.

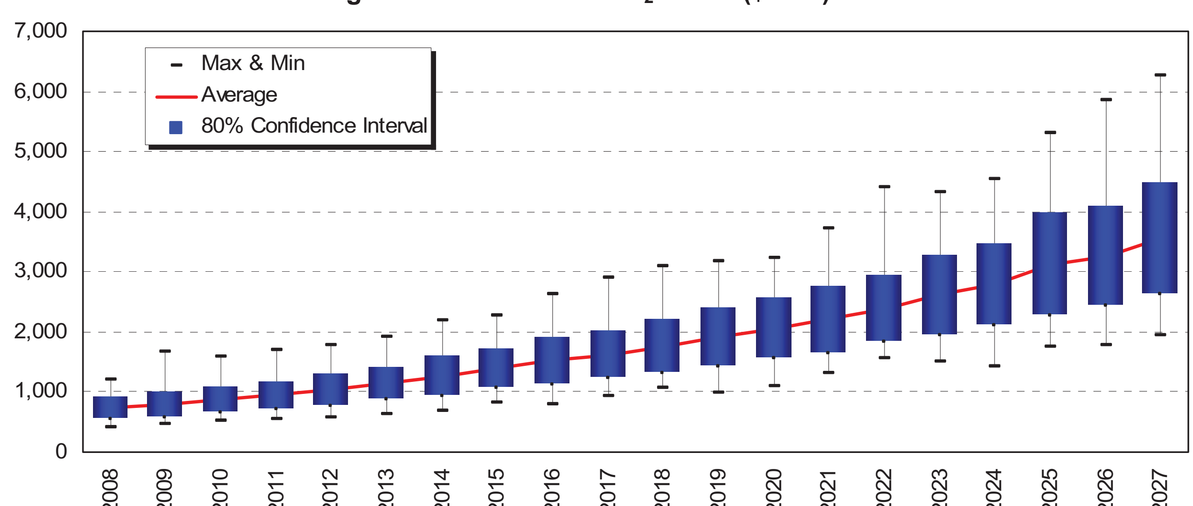
The goals of this Executive Order became law when SB 6001 was signed on May 3, 2007. The law reduces the GHG emissions of electric utilities by establishing an emissions performance standard of 1,100 pounds of GHG per MWh of new base load generation.

Washington state has proposed mercury legislation levels of 8.7 lb/MWh from all sources by 2013, with mandatory plant compliance of utilities by 2017. Trading is allowed for the first three years. The allocation base is tentatively set at 70 percent to existing sources, 5 percent to new sources, and the balance held for possible future distribution. Final mercury rules are expected by September 2007.

EMISSIONS MEASUREMENT AND MODELING

To evaluate the impact of emissions regulation on market prices and resource dispatch, estimates of the amounts of dollars to "tax" certain emissions were made. This tax is used as an economic indicator of lower emissions.

Figure 4.1: Base Case SO_2 Costs ($/Ton)



Valuing emissions is an important part of the IRP modeling process. Mercury, SO_2, and NO_x are modeled using a lognormal distribution, whereas CO_2 is modeled based on a sampling distribution of 300 Monte Carlo iterations. Each of the four modeled emissions types is discussed below.

SO_2 emissions average $808 per ton in 2008 and escalate to $2,571 per ton in 2027 in nominal dollars. SO_2 has an actively traded market so emissions costs and projections are readily obtained. Figure 4.1 shows the minimum, maximum and average levels of SO_2 emissions costs.

NO_x emission costs are $2,248 per ton beginning in 2010 when regulations begin and escalate to $3,875 per ton in 2027. The NO_x market will operate in a manner that is very similar to the SO_2 market. Figure 4.2 shows the data for NO_x cost projections.

Mercury is somewhat problematic to model because trading does not begin until 2010 and many states have decided to opt out of the national trading market under CAMR. Projections of mercury costs are not readily available. The IRP bases its cost estimates on a variety of governmental and private sources. Mercury costs start

Figure 4.2: Base Case NO_X Costs ($/Ton)

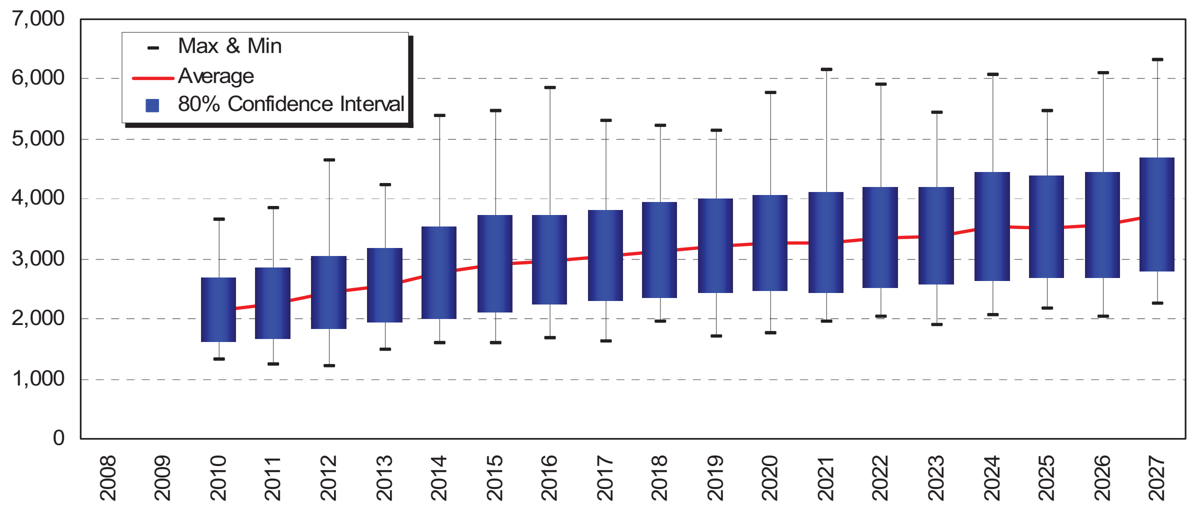
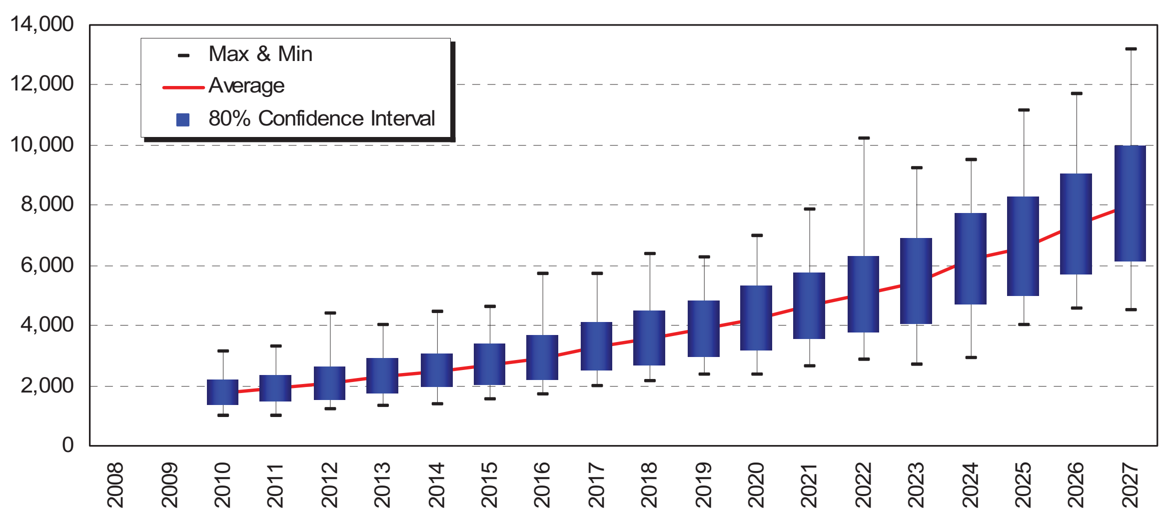


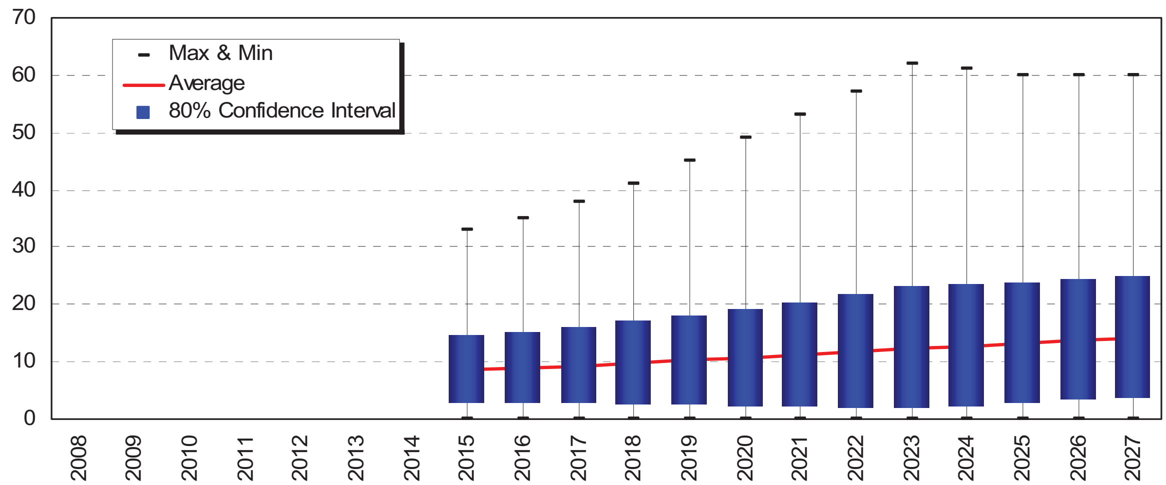
Figure 4.3: Base Case Mercury Costs ($/Ounce)



in 2010 at $1,739 per ounce and escalate to $4,863 per ounce in 2027 (nominal dollars). Mercury emission cost estimates are shown in Figure 4.3.

CO_2 emissions are modeled based on a probability distribution of the 300 Monte Carlo iterations of AURORAxmp run for the Base Case. The mean value of the probability distribution equals the projected cost of the National Commission on Energy Policy recommendations in their 2004 study. The projected costs from that study have been escalated to account for inflation. Figure 4.4 shows the projected CO_2 values by year. Costs average $8.94 per ton in 2015 and increase to $14.34 per ton in 2027.

Figure 4.4: Base Case CO_2 Costs ($/Ton)



5. TRANSMISSION PLANNING

Transmission Construction in the Palouse Region, Southeastern Washington

INTRODUCTION

Comprehensive coordination of transmission system operations and planning activities with regional transmission providers is necessary to maintain reliable and economic transmission service for the region's end-use customers. Transmission providers and interested stakeholders are implementing changes in the region's approach to planning, constructing and operating the system under new rules promulgated by the Federal Energy Regulatory Commission (FERC) and under state and local siting agencies. This section was developed in full compliance with Avista's FERC Standards of Conduct, governing communications between Avista's merchant and transmission functions.

AVISTA'S TRANSMISSION SYSTEM

Avista owns and operates an electric transmission system comprised of approximately 623 miles of 230 kilovolt (kV) line and 1,537 miles of 115 kV line. The company also owns an 11 percent interest in 495 miles of a 500 kV line between Colstrip and Townsend, Montana. The transmission system includes switching stations and high-voltage substations with transformers, monitoring and metering devices, and other system operation-related equipment. The system is used to transfer power from the company's generation resources to its retail load centers. Avista also has network interconnections with the following utilities:

- Bonneville Power Administration (BPA)
- Chelan County PUD
- Grant County PUD
- Idaho Power Company
- NorthWestern Energy
- PacifiCorp
- Pend Oreille County PUD
- Puget Sound Energy

In addition to providing enhanced transmission system reliability, these network interconnections serve as points of receipt for power from generating facilities outside the company's service area, including the Colstrip generating station, Coyote Springs 2 and the Mid-Columbia hydroelectric facilities. These interconnections provide for the interchange of power with entities within and outside of the Pacific Northwest, including the integration of long-term and short-term contract resources. Additionally, the company has interconnections with several government-owned and cooperative utilities at transmission and distribution

CHAPTER HIGHLIGHTS

- Avista is in the fifth year of a $130 million transmission improvement project.
- Avista has over 2,100 miles of high voltage transmission.
- The company is actively involved in the regional transmission planning efforts of ColumbiaGrid.
- The cost of new transmission lines and upgrades are included in the 2007 Preferred Resource Strategy.
- New construction costs approximately $1.4 million per mile of 500 kV transmission line.

voltage levels, representing non-network, radial points of delivery for service to wholesale loads.

Avista is currently in the fifth year of a multi-year, $130 million, transmission upgrade project. The planned upgrades will add over 100 circuit miles of new 230 kV transmission line to the company's system and increase the capacity of an additional 50 miles of transmission line. The transmission upgrade project also includes the construction of two new 230 kV substations and the reconstruction of three existing transmission substations. Upgrades at six 230 kV substations are being undertaken to meet capacity requirements, to upgrade protective relaying systems and meet reliability standards. In total, Avista will work on 11 of 13, or 85 percent, of its 230 kV substations. The telecommunication system is also being upgraded with the installation of fiber and digital microwave systems to improve system control, monitoring and protection. The company's most significant transmission projects are described below.

BEACON-BELL 230 KV

The company increased the capacity of two parallel path transmission lines from its Beacon substation to BPA's Bell substation. The project doubled the line capacity to 800 MVA and increased equipment ratings from both substations. The project mitigates overloads between the largest Avista and BPA substations in Spokane to improve load service to the Spokane area. The upgrade to Bell #4 was completed in December 2005 and Bell #5 was energized in April 2007.

BEACON-RATHDRUM 230 KV

Avista recently reconstructed 25 miles of single circuit 230 kV transmission line to a double circuit 230 kV line between Rathdrum, Idaho, and Spokane, Washington.

DRY CREEK

A second 230/115 kV transformer was added to the Dry Creek substation to improve load service and system reliability in the Lewiston-Clarkston area. The new transformer provides back-up for the North Lewiston 230-115 kV transformer. This project also included the construction of the 115 kV portion of the Dry Creek Substation and the loop-in of an area 115 kV transmission line. This project was completed in the fall of 2006.

PALOUSE REINFORCEMENT

The company is constructing 60 miles of 230 kV transmission line between the Benewah and Shawnee substations to relieve congestion on the existing Benewah-Moscow 230 kV line. The project provides a second 230 kV transmission line between the company's northern and southern load service areas, which significantly improves system reliability. Several components of the Palouse Project were energized and placed into service in 2006, including the double circuit Shawnee-Colfax 230 kV and 115 kV line section and the Benewah Substation rebuild.

PINE CREEK SUBSTATION

The company reconstructed the Pine Creek 230 kV Substation in November 2003. This facility is located in Pinehurst, Idaho.

SPOKANE VALLEY REINFORCEMENT

Avista is adding 500 MVA of 230 kV to 115 kV transformation at the new Boulder Substation.

WEST OF HATWAI TELECOM PROJECT

The ability to communicate, monitor and control transmission equipment is vital to providing reliable service. The West of Hatwai (WOH) Telecom Project is comprised of several sub-projects. The Noxon-Pine Creek fiber project completes a telecommunication ring from Spokane to the Noxon Rapids Hydroelectric Project. The ring provides redundant communication paths, so the loss of one side of the ring will not eliminate the ability to control equipment. The ring is also required to implement the Clark Fork Remedial Action System (RAS), which drops generation at the Clark Fork Projects after critical transmission outages to ensure system reliability. Another component of the Clark Fork RAS includes the addition of fiber from the Cabinet Gorge generation units to the 230 kV Cabinet Substation. The Hatwai-North Lewiston fiber project completed a fiber ring around the Lewiston-Clarkston load service area. This project is also part of a RAS to improve reliability in the Lewiston area. All three projects were completed in 2006.

As noted in the August 2002 West of Hatwai letter of agreement with BPA, these projects are coordinated to support and enhance BPA transmission projects. Collaboration has allowed both parties to achieve a least-cost service plan addressing commercial transactions, load service and regional reliability issues. The Avista and BPA plan was reviewed by peer utilities, approved by other Northwest transmission owners and by utility members of the Western Electricity Coordinating Council (WECC). The Northwest Power Pool (NWPP) Transmission Planning Committee agreed that a blended plan was superior to stand-alone plans separately executed by the company and BPA.

Avista plans and operates its transmission system pursuant to applicable criteria established by the North American Electric Reliability Corporation (NERC), WECC and the NWPP. Through its involvement in WECC and the NWPP standing committees and sub-committees, the company participates in the development of new and revised criteria, and coordinates planning and operation of its transmission system with neighboring systems. The company is subject to periodic performance audits through participation in these regional organizations.

Portions of the company's transmission system are fully subscribed for transferring power output of company generation resources to its retail load centers. Transmission capacity that is not reserved to move power to satisfy long-term (greater than one year) obligations is used to facilitate short-term purchases and sales to optimize the company's resources, as well as to provide wholesale transmission service to third parties pursuant to FERC requirements under Orders 888 and 889. It is important to note that the implementation of FERC policies and practices under Orders 888 and 889, and subsequent FERC orders, can occasionally restrict our ability to optimize transmission system resources in specific cases. Transmission capacity that might have been either reserved or recalled to deliver lower-cost short-term resources for service to native load customers may not be available because of FERC policies requiring transmission capacity to be available for other parties. To the extent a third party has secured firm capacity rights on Avista's transmission system, including future rollover rights, that transmission capacity will not be available for the company to serve native load.

REGIONAL TRANSMISSION SYSTEM

BPA operates over 15,000 miles of transmission facilities throughout the Pacific Northwest. BPA's system represents approximately 75 percent of the region's high voltage (230 kV or higher) transmission grid. The company uses the BPA transmission system to transfer output from its remote generation sources to the company's transmission system, such as Colstrip, Coyote Springs 2 and the Washington Public Power Supply System Washington Nuclear Plan No. 3 settlement contract. The company also contracts with BPA to transfer power from the company's local resources to 10 of its remote retail load areas.

The company participates in a number of regional and BPA-specific forums to coordinate system reliability issues and to manage costs associated with the BPA transmission system. The company participates in BPA transmission and power rate case processes and in BPA's Business Practices Technical Forum, to ensure BPA transmission charges remain reasonable and support system reliability and access. The company also works with BPA and other regional utilities to coordinate major transmission facility outages.

Future regional resource development will require new transmission assets. BPA has indicated that financing restrictions may hamper its ability to construct new transmission to support these resources. BPA transmission customers seeking firm capacity for their new resources may be required to provide a form of long-term financing for BPA to facilitate needed transmission project construction on its system.

REGIONAL TRANSMISSION ISSUES

Coordinated transmission planning has historically occurred through various NWPP workgroups. ColumbiaGrid is a more formalized Northwest organization that has been created to develop a regional transmission plan, assess transmission alternatives (including non-wires alternatives) and provide a decision-making forum for new projects and cost allocation methods. ColumbiaGrid was formed on March 31, 2006, as a non-profit, membership, Washington state corporation. The current members of ColumbiaGrid are Avista, BPA, Chelan County PUD, Grant County PUD, Puget Sound Energy, Seattle City Light and Tacoma Power.

During the first quarter of 2007, Avista signed a transmission planning agreement with ColumbiaGrid to address regional transmission issues. ColumbiaGrid will perform a number of services under the Planning Agreement. It will prepare a Biennial Transmission Plan and, as part of that process, will perform system assessments of the parties' transmission systems and identify projected transmission needs. ColumbiaGrid will also facilitate a coordinated planning process for the development of multi-transmission system projects.

THE BIENNIAL TRANSMISSION PLAN

Under the planning agreement, ColumbiaGrid will prepare and adopt a Biennial Transmission Plan during each two-year planning cycle. The plan will have a 10-year planning horizon, or longer if required by FERC's pro forma open access transmission tariff. Throughout the planning process, drafts of the Biennial Plan will be posted on the ColumbiaGrid website as they become available.

As a primary component of the plan, ColumbiaGrid will perform annual system assessment of the parties' transmission systems. The system assessment will determine the ability of each planning party to serve, consistent with the planning criteria, its network load and native load obligations, and other existing long-term firm transmission obligations anticipated to occur during the planning horizon. Projected inabilities to meet such obligations are identified and solutions proposed, outlining those solutions that can be implemented by a party on a single system basis versus those transmission solutions that impact the regional transmission grid ("multi-system projects"). Those transmission system modifications that will impact only a single party's transmission system are included in ColumbiaGrid's biennial plan for informational purposes.

COORDINATED PLANNING OF MULTI-SYSTEM PROJECTS

ColumbiaGrid will facilitate coordinated planning of all multi-system transmission projects. If the annual system assessments identify a need that implicates a multi-system transmission project, ColumbiaGrid will develop conceptual transmission solutions through the creation and use of study teams made up of members from a number of stakeholder categories. The objective of a study team will be to develop a transmission plan that will resolve a reliability need or provide sufficient capacity for a request for transmission service in a timely fashion.

ColumbiaGrid's unique structure provides a means for resolving disputes related to multi-system projects. Transmission system modifications that will impact more than one transmission system must be approved by a majority vote of the ColumbiaGrid board before they can be incorporated into the final biennial plan. Projects where all affected parties have reached agreement will be included in the draft biennial plan submitted to the board. In the event agreement is not reached by all affected parties, ColumbiaGrid staff may make a recommendation to the Board on whether to include it in the draft biennial plan and affected parties may provide comment to the ColumbiaGrid board. ColumbiaGrid staff's recommendation can include an equitable allocation of costs to construct the facilities and an allocation of transmission capacity increased or maintained. Upon a majority vote by the ColumbiaGrid Board, such a project, with its respective allocations, will be included in the final biennial plan which ColumbiaGrid planning parties are obligated to uphold. The process provides a means to further address any such disputes with the Federal Energy Regulatory Commission.

The ColumbiaGrid coordinated planning process will be conducted in an open and transparent manner with ColumbiaGrid seeking to notify all affected and interested parties regarding study team activities. Additionally, ColumbiaGrid will also develop a protocol to foster the collaborative involvement of affected tribes and states, including agencies responsible for facility siting, utility regulation and general energy policy. The ColumbiaGrid planning process will provide the necessary coordination and dispute resolution to enable the construction of necessary transmission facilities to integrate needed new resources identified in Avista's 2007 IRP.

MODELING TRANSMISSION COSTS

Transmission costs to integrate new resources into the company's system were estimated by Avista's Transmission Department. Estimates were not modeled in AURORAxmp, but rather in the proprietary PRiSM model that matches different generating resources with company-specific resource requirements. Construction quality estimates have not been completed for any of the transmission alternatives included in this IRP; estimates are based on engineering judgment only. There is an inverse relationship between transmission project size and the certainty of the estimates. A 50 MW resource can be integrated in many places on the system. A 400 MW plant can be integrated at some locations, while a 750 MW or 1,000 MW plant has very limited placement options. A detailed regional process would probably be undertaken to determine the precise impacts and integration costs before an actual plant placement decision would be made.

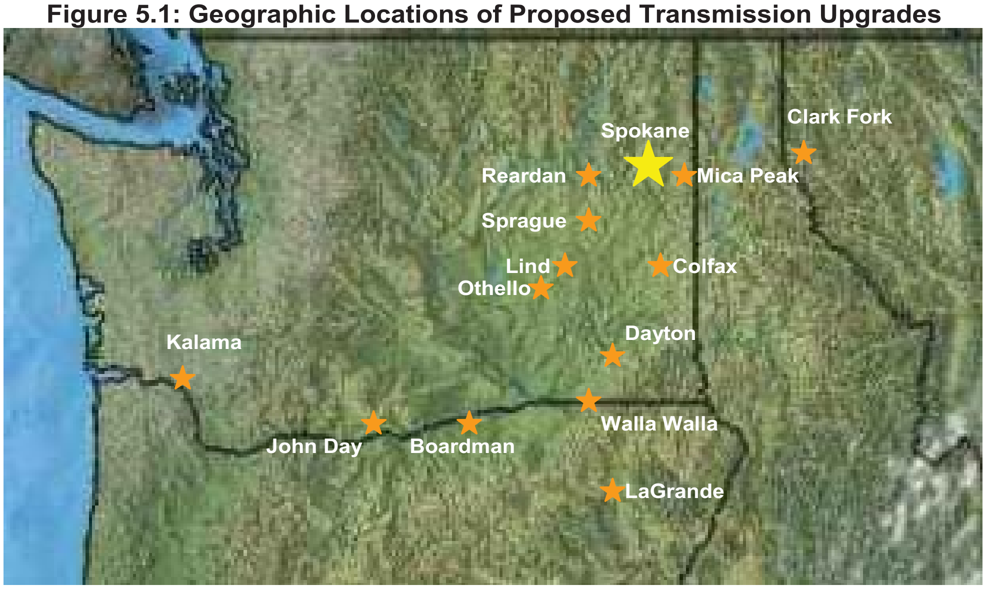
The Estimated Resource Integration Costs for the 2007 IRP study evaluated 50 MW, 100 MW, 250 MW and greater than 400 MW generation sizes at 23 different locations. The study was indifferent to the generation asset fuel type. Wind projects have a low capacity factor, in the 30-40 percent range, but still require transmission that corresponds to the nameplate capacity of the project. This is the same transmission requirement as a natural gas-fired turbine or any other resource type. The study was divided into 10 generic project areas located outside of the company's service territory and nine major areas within the company's service territory. Areas located within Avista's service area tend to be higher quality estimates because of the increased level of system knowledge.

ESTIMATED RESOURCE INTEGRATION COSTS FOR THE 2007 IRP STUDY

The following sections provide an overview of the Avista Estimated Resource Integration Costs for the 2007 IRP Study. A copy of the complete study may be found at the company's IRP Website (www.avistautilities.com). Several different project sizes were requested for this analysis. Because transmission capability comes in "lumps," and plant sizes may be altered based upon available transmission capacity at a particular site, the alternatives were broken into 50, 100, 400, 750 and 1,000 MW sizes.

Integration points were roughly divided into points that are inside and outside of Avista's transmission system. There is some overlap for larger amounts of generation, which could have broad impacts to our system as well as neighboring systems. A rigorous study has not been completed for any of the foreign system alternatives because it is impossible to provide meaningful study results without the knowledge, input and approval of the owners of those systems. Only limited study work has been done for the alternatives within our system because detailed machine parameters are only available when an actual project is specified. In regard to neighboring system impacts, an approximate worst case cost estimate has been assigned to these resources based on engineering judgment. Interconnection costs are listed for locations within the Avista transmission system.

Figure 5.1: Geographic Locations of Proposed Transmission Upgrades



All internal cost estimates are in 2015 dollars and are based on engineering judgment with a 50 percent error band. Time to construct is defined from the beginning of the permitting process to when the line is energized. An illustration of various northwest transmission upgrade projects is shown in Figure 5.1.

External to the Avista System

For areas outside of Avista's transmission system, Avista-LSE would be required to undertake a transmission request on the BPA or another transmission system. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area. Preliminary construction estimates are $1.4 million per mile of new 500 kV lines.

Boardman, Oregon

The present transmission system serving the Boardman generating complex consists of two 500 kV circuits which are owned and operated by Portland General Electric (PGE). The PGE circuits integrate into several 500 kV circuits owned and operated by the Bonneville Power Administration (BPA). Boardman is located to the north and east of several transmission constraints, which could be an issue with BPA's transmission pricing and availability policies.

Integrating 400, 750 or 1,000 MW at Boardman would likely require reinforcement of PGE's and BPA's local 500 kV system and might require additional 500 kV facilities downstream of the plant.

John Day, Washington

The transmission system serving the John Day generating complex consists of several 500 kV circuits which are owned and operated by BPA. John Day is located northeast of several transmission constraints, which could be an issue with respect to BPA's transmission pricing and availability policies.

The North of John Day Path is constrained, depending upon generation on the upper and mid-Columbia River. Because of the existing constraints, a transmission integration study on the BPA system would be required to determine if 50 to 100 MW could be integrated at a low cost.

Kalama, Washington

The transmission system serving the Kalama area consists of two 500 kV and two 230 kV circuits owned and operated by BPA. This area is located in the center of several transmission constraints which could be an issue with BPA's transmission pricing and availability policies. Integrating 400 MW would most likely require reinforcement to BPA's local 500 kV system and might require additional 500 kV facilities "downstream" of the plant. Integrating 750 or 1,000 MW would require reinforcement to BPA's local 500 kV grid and additional 500 kV facilities downstream of the plant. Preliminary construction estimates are $1.4 million for each mile of new 500 kV line. Because the amount of new transmission will be unknown until studies are completed, total integration costs are not known. Costs for this alternative could easily exceed $1.5 billion.

LaGrande, Oregon

The transmission system serving the LaGrande area consists of a 230 kV BPA line terminating at McNary and a 230 kV Idaho Power Company (IPC) line, which terminates at Brownlee. IPC also owns a 69 kV line out of LaGrande which is normally operated in a radial configuration. LaGrande lies in the center of one of the four lines which make up the Idaho to Northwest transmission path (the Brownlee-McNary 230 kV line). There is presently a WECC rating process that is being undertaken for the Idaho to Northwest path which could affect available capacity on these lines. Because of the rating study, there is no way to perform a reasonable study for the 50 to 100 MW of additional generation in this area until that study has been resolved.

Northeast Wyoming

The transmission system serving northeastern Wyoming consists of several 230 kV circuits, which are owned and operated by PacifiCorp and Black Hills Power Company. Additional circuits are owned or planned by Basin Electric. Northeast Wyoming is presently surrounded by several transmission constraints.

Moving between 400 and 1,000 MW from this area into our native system would be difficult, time consuming and most likely expensive because of all of the constraints surrounding this area. In the lowest power and lowest cost case at least one 500 kV line would be required into the IPC system. In the 1,000 MW case, two 500 kV lines might be required. Depending upon the arrangements, wheeling expense might also be incurred. Because the amount of new transmission will not be known until studies on the area are completed, total integration costs are presently unknown, but are estimated to be $2.0 to $3.0 billion.

Southeast Idaho

The transmission system serving southeastern Idaho consists of a 500 kV line, several 345 kV lines, and several 230 kV circuits which are owned and operated by PacifiCorp and IPC. Southeastern Idaho is east and west of several transmission constraints. Because Avista owns no transmission in southeastern Idaho, Avista-LSE would be required to undertake a transmission request on either the PacifiCorp or IPC systems in the area. This work would be required to determine integration costs and wheeling service to deliver energy to the Avista load area. Because there are constraints from this area to the east and west, moving 400 to 1,000 MW from this area into our native system would be difficult, time consuming and expensive from a construction standpoint. In the lowest power, lowest cost case at least one additional 345 kV line would be required into the center of the IPC system. In the 1,000 MW case, two 500 kV lines might be required to connect the Avista system. Wheeling expense might also be incurred. Because the amount of new transmission will not be known until studies on the area are completed, total integration costs are presently unknown, but are estimated to be $1.0 to $3.0 billion.

Central Alberta, Canada

There is currently no available transfer capability or suitable method of inexpensively integrating energy from central Alberta into the Avista system. Because of the distances and costs involved, integration into the United States power grid at capacity levels less than 2,000 to 3,000 MW is unlikely. Transmission from central Alberta would probably be a direct current (DC) 500 kV line because of the capacity required for the economics of the project. It is assumed that one of the DC terminals would be either in the Spokane area or at the Mid-Columbia. Avista could purchase portions of this energy to be delivered to its system from either location. A regional scoping effort to estimate costs for this and similar projects has been completed and may be obtained from the Northwest Power Pool, assuming that the Critical Infrastructure Information requirements are met. Estimates for these projects are $2.0 to $5.0 billion.

A 300 MW transmission interconnection project between southern Alberta and northern Montana (MATL) has been proposed. Available capacity on this project is unknown at this time. However, additional transmission would be required between central Alberta and southern Alberta, as well as from northern Montana to the Spokane area. Until it is known if the MATL project will be constructed, it is difficult to provide estimates on whether 50 MW of energy can be economically integrated into our system from central Alberta. Avista-LSE would need to undertake a transmission request on the BPA system to determine integration costs and wheeling service to deliver the energy to the Avista load area.

Integrating anything over 300 MW would probably require a high voltage DC tie directly from the resource, which would most likely be integrated into the Mid-Columbia area. Integration of more than 400 MW from the Mid-Columbia could cost $300 to $500 million, exclusive of the 500 kV DC tie project.

Central Washington

The transmission system serving central Washington consists of multiple 500 kV and 230 kV circuits that are owned and operated by several entities. One 230 kV line into the Mid-Columbia area is owned by Avista and PacifiCorp. Presently there is no long term available transfer capability from central Washington into the Avista system via the jointly owned transmission line. There is a regional study, through the Northwest Power

Pool in progress, analyzing resource integration in the Mid-Columbia area (including Avista's system). This study should be completed in 2007.

The mid-Columbia area is presently in a constrained state, depending upon generation on the mid-Columbia River. Because of existing constraints, a transmission integration study (most likely on the BPA or Avista system) would be required to determine if 50 to 1,000 MW could be integrated. Integrating more than 400 MW from the Mid-Columbia would be expected to cost $300 to $500 million.

Eastern Montana

The present transmission system to the west of (and serving) the present generation in Montana is a double circuit 500 kV line and two 230 kV lines. In a regional study, under the auspices of the Northwest Power Pool (NWPP), NTAC indicated that either additional transmission or upgrades would be required to integrate energy from Montana. Eastern Montana also lies east of several transmission constraints, which could be an issue with BPA's transmission pricing and availability policies.

A more detailed study effort focusing on constraints from central and eastern Montana will be released in 2007. This study will identify integration constraints and costs. Avista-LSE would need to undertake a transmission request on the NWE system and fund a study to determine potential impacts on the BPA system. This work would be required to determine integration costs and wheeling service to deliver energy to the Avista load area. Since two transmission systems (BPA and Northwestern Energy) may be involved in the integration of this project, the merchant may pay two wheeling charges for transmission service.

Walla Walla, Washington

The transmission system serving the Walla Walla area is a single 230 kV line owned by Avista and PacifiCorp. There is also a 115 kV line owned by BPA and a 69 kV line owned by PacifiCorp. Avista has contractual transmission rights, but owns no transmission in the Walla Walla area. Therefore, Avista-LSE would be required to undertake a transmission request on the PacifiCorp transmission system. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area. Due to the presently constrained paths in the area, such as the Idaho to Northwest path, a transmission integration study on the PacifiCorp system would be required to determine integration costs.

INTEGRATION WITHIN THE AVISTA TRANSMISSION SYSTEM

Table 5.1 provides a summary view of the estimated integration costs the company would expect for various resources connected to its transmission system. Discussions of each interconnection area follow.

Table 5.1: Estimated Integration Costs Inside Avista's Systems ($Millions)

Location	50 MW	100 MW	250 MW	400+ MW
Sprague, Wash.	N/A	N/A	$58	$80+
Spokane/Coeur d'Alene	$3	$7	$32	up to $500
Mica Peak	$4	N/A	N/A	N/A
Clark Fork Hydro	$0	N/A	N/A	N/A
Dayton, Wash.	$32	$32	N/A	N/A
Reardan, Wash.	$2	$13	N/A	N/A
Lind, Wash.	$1.5	$6	N/A	N/A
Othello, Wash.	$1.5	N/A	N/A	N/A
Colfax, Wash.	$1.5	N/A	N/A	N/A
Sprague, Wash.	N/A	N/A	$58	$80+

Sprague, Washington

The transmission system serving the Sprague area is a low capacity 115 kV line. It is not suited for integrating 250 to 400 MW in its present configuration. Each connection below (which are the major transmission interconnection points in the area), would require 230 kV transmission and substation work for the generation integration. Any added generation greater than 400 MW will increase costs and have regional impacts.

To integrate 250 MW at Westside, the existing 115 kV line would have to be rebuilt as 230/115 double circuit back to the main BPA corridor. An additional 230 kV line could be constructed utilizing BPA's transmission corridor or by building a new 230 kV line. This project would take approximately four years and $58 million to construct.

To integrate 250 MW at Rosalia on the Benewah-Shawnee 230 kV line, 30 miles of new 230 kV line would have to be constructed to Rosalia and a 230 kV switching station would need to be built. This project would take about four years and $35 million to complete.

To integrate 400 MW at Westside, the existing 115 kV would have to be rebuilt as a 230/115 kV double circuit back to the main BPA corridor. To connect at Westside, an additional 230 kV line would need to be constructed utilizing BPA's transmission corridor or by building a new 230 kV line. This project would cost approximately $80 million and take four years to complete.

In order to integrate 400 MW at Rosalia on the Benewah-Shawnee 230 kV line, a new 30-mile long 230 kV line would have to be constructed to Rosalia and a 230 kV switching station would also have to be built. This project would take four years and approximately $50 million to complete.

Spokane/Coeur d'Alene

There are a number of 230 kV stations and transmission lines in the Spokane/Coeur d'Alene area that would make good generation interconnection points. Westside, Beacon, Bell, Boulder and Rathdrum are all large stations with 230/115 kV transformation in the Spokane/Coeur d'Alene area. However, integrating large generation in this area could pose thermal loading problems on the underlying 115 kV system. Without a specific interconnect point, all of the needed 115 kV work is an approximation. The Spokane/Coeur d'Alene area covers too much land to be more specific on costs. Additional generation greater than 250 MW will further increase costs and regional impacts.

Integrating 50 MW of new generation in the Spokane/Coeur d'Alene area can be done with 10 or less miles of 115 kV reconductor work. This type of project would take approximately one year and $3 million to complete. 100 MW could be integrated into this area with less than 30 miles of 115 kV line reinforcement. This type of project would take approximately two years and $7 million to complete.

Integrating more than 250 MW of generation in the Spokane/Coeur d'Alene area would require 230 kV work. This would necessitate extensive levels of 115 kV reconductoring. The radial operation of Avista's 115 kV lines in Spokane and Coeur d'Alene or generation dropping for 230 kV outages would probably be needed. Additional 230 kV work would likely be needed depending on the interconnection point. This project could cost $32 to $500 million and take five years to complete.

Mica Peak

Mica Peak is near existing Avista 115 kV lines with available capacity. 50 MW could be integrated at the

Post Falls substation with six miles of 115 kV line and a new breaker position at Post Falls. This project would cost about $4 million and take one year to complete.

Clark Fork Hydro Upgrades

The present transmission system in the Clark Fork area consists of both Avista and BPA 230kV lines that integrate the western Montana hydro (WMH) projects. The WMH refers to the four major hydroelectric plants operated in northwestern Montana and on the northern Montana-Idaho border. These include the federally-operated Libby and Hungry Horse projects and Avista's Cabinet Gorge and Noxon Rapids (Clark Fork) projects. After completion of planned upgrades to Cabinet Gorge and Noxon Rapids, these projects will have peak generation capacities of 268 MW and 558 MW, respectively, for a combined capacity of 826 MW.

Avista and BPA have a WMH operating agreement that provides a 50-50 allocation of a 1,700 MW operating limit between the federal and Avista projects. This agreement pertains to Avista-LSE's ability to operate its Clark Fork Projects for service to Avista's bundled retail native load customers. After completion of upgrades, Avista's total Clark Fork hydro generation capacity will be 24 MW below Avista's WMH operational allocation of 850 MW. Dependent upon continuation of the operational allocation of WMH hydro capability between Avista and BPA, no new transmission upgrades will be needed for Avista to integrate the planned upgrades of its Clark Fork hydro projects.

Dayton, Washington

The present transmission system serving the Dayton, Wash., area is a single 230 kV line with dual ownership by Avista and PacifiCorp. There is also a 115 kV line in the area owned by BPA and a 69 kV line owned by PacifiCorp.

Fifty to 100 MW could be integrated on the Dry Creek-Walla Walla 230 kV line at the ownership change between Avista and PacifiCorp with a new switching station and a 15 mile 230 kV line to this location. This line lacks capacity to support 50 to 100 MW due to current contractual obligations. Therefore, the Dry Creek-Walla Walla 230 kV line would need to be re-conductored to support additional capacity. The project would take approximately four years and $32 million to complete. There may be a potential real time solution using real time thermal monitoring and the Valley Group's Cat-1 or similar technology.

Reardan, Washington

The present transmission system serving the Reardan, Wash. area is a low capacity 115 kV line. Fifty MW could be integrated at the Reardan substation by re-conductoring the 115kV line from Garden Springs to Sunset along with a new air switch at Westside on the Nine Mile line. This project would require approximately one year of construction time and cost about $2 million. One hundred MW could be integrated by re-conductoring the 115 kV line from Reardan to Devils Gap along with a new line out of Reardan. The 100 MW project would cost approximately $13 million and take two years to complete.

Lind, Washington

The transmission system serving the Lind area is a low capacity 115 kV line and two 115 kV lines that are operated in a radial configuration. Very little new transmission would be required to integrate 50 MW at the Lind substation. The project would take about one year and $1.5 million to complete. Integrating 100 MW would require re-conductoring the 115kV line from Lind to Warden. The project would take about one year and $6 million to complete.

Othello, Washington

The transmission system serving the Othello, Wash, area consists of low capacity 115 kV lines. Fifty MW could be integrated at the Othello substation with very little new transmission. The project would take about one year to complete at a cost of $1.5 million.

Colfax, Washington

The present transmission system serving the Colfax, Wash., area is a low capacity 115 kV line. Fifty MW could be integrated at the East Colfax substation with very little new transmission being required. The project would cost about $1.5 million and take approximately one year to finish.

6. MODELING APPROACH

Transformer at Coyote Springs 2

INTRODUCTION

This section discusses market modeling assumptions used to value each resource option and the combination of costs and benefits to select the Preferred Resource Strategy (PRS). The analytical foundation for the 2007 IRP is a fundamentals-based electricity model of the entire Western Interconnect (WI). Understanding market conditions in the different geographic areas of the WI is important because many areas are linked by transmission facilities and the regional markets are correlated.

Avista's IRPs prior to 2003 relied on externally generated market price forecasts that did not consider company operations. This IRP builds on prior analytical work by maintaining the link between the WI market and the changing value of company-owned and contracted resources. The company's portfolio value is linked to its loads, resources and contractual arrangements, both for existing and prospective resource options, and for meeting future obligations.

The Preferred Resource Strategy is developed using a multi-step approach. New and existing resources are combined to simulate hourly operations for the WI to develop a long-term hourly electricity market price forecast. This market forecast values each resource option Avista might select as part of its PRS. Figure 6.1 illustrates the company's IRP modeling process.

MARKET MODELING

AURORAxmp is a fundamentals-based electricity market forecasting tool that tracks the value of the company's existing resource portfolio as well as potential new resource portfolios. Additional details about AURORAxmp can be found in Technical Advisory Committee presentations at the company's IRP Website. AURORAxmp is used to simulate the WI for this IRP. The WI includes the states west of the Rocky Mountains, the Canadian provinces of British Columbia and Alberta and the Baja region of Mexico, as shown in Figure 6.2. The WI is separated from the Eastern Interconnect and ERCOT systems, with the exception of eight inverter stations. The WI follows operation and reliability guidelines administered by the Western Electricity Coordinating Council (WECC).

CHAPTER HIGHLIGHTS

- AURORAxmp is used to model hourly operations for the entire Western Interconnect.
- The company performed 300 iterations of Monte Carlo market analysis with varying wind, hydro, load, natural gas prices, emissions and thermal outages for each evaluated future.
- The Preferred Resource Strategy was developed using the proprietary Avista Preferred Resource Strategy Model (PRiSM).
- This IRP considers generation, transmission and emissions costs.

Figure 6.1: Modeling Process Diagram

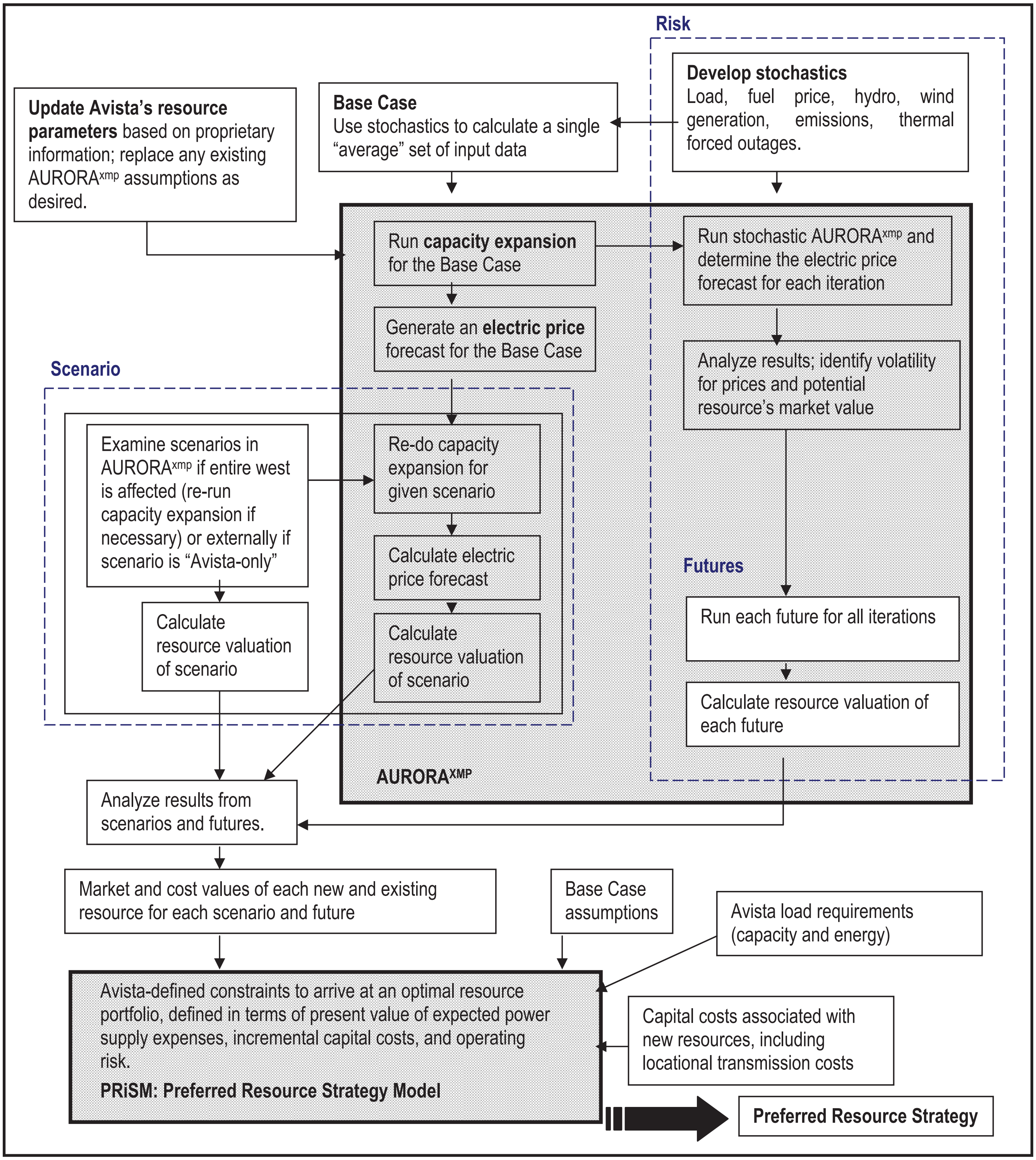


Figure 6.2: NERC Interconnection Map

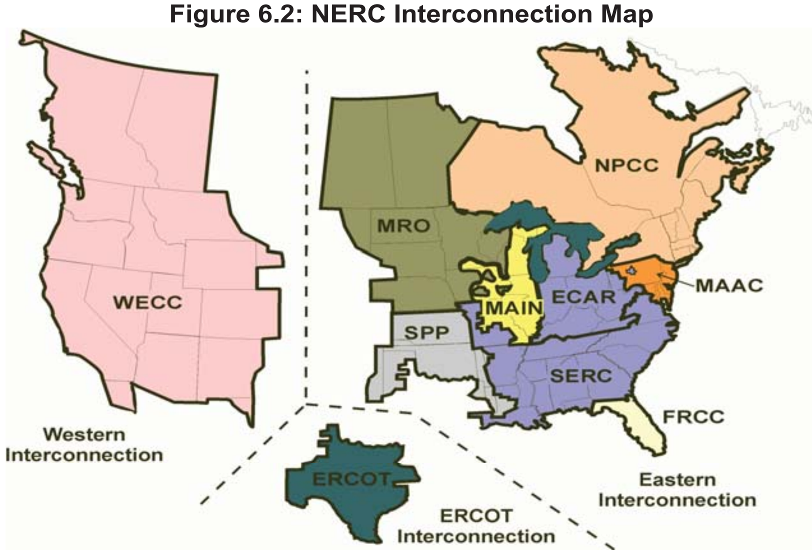


Table 6.1: AURORAxmp Pools and Zones

Northwest	California	Rocky Mountain	Desert Southwest	Independent
W. Wash.	Northern	Wyoming	Arizona	British Columbia
W. Oregon	Central	Colorado	New Mexico	Alberta
E. Wash.	South	Utah	S. Nevada	E. Montana
C. Oregon	Baja	N. Nevada		S. Idaho
W. Montana				

The model separates the WI into 20 zones based on load concentrations and transmission constraints. Zones are grouped into pools for regional capacity planning. The pools do not reflect regional transmission agreements or reserve sharing but are designed for regional proximity of resources. Table 6.1 shows the geographic pools and zones modeled in the IRP. Some zones are modeled independently due to significant transmission constraints and/or international boundaries.[1]

Electric models range in their ability to emulate power systems. Some models account for every bus and transmission line; others utilize regions or zones. An IRP requires regional price and plant dispatch information. Table 6.1 provides a list of zones contained in each pool.

The Northwest is modeled as five separate zones. This differs from the 2005 IRP where the Northwest was modeled as a single zone. Montana is split into east and west load areas to reflect transmission constraints on the Northwestern system. AURORAxmp has the ability to model the Northwest as nine separate zones. The nine-area topology was not selected because of long solution times and because the five-area topography was found to better represents Northwest market operations.

KEY ASSUMPTIONS AND INPUTS

HYDROELECTRIC GENERATION

The Northwest and British Columbia have substantial hydro generation capacity. A favorable characteristic of hydro power is the ability to provide short periods of

[1] Baja, Mexico, is included in the California pool because of tight interconnection with Southern California. This zone could have been modeled as an independent zone, but it has no impact on Avista's resource strategy or the Northwest's electricity marketplace.

near-instantaneous generation. This characteristic is particularly valuable for meeting peak load demands, shaping load and selling surplus energy during peak hours. A drawback of hydro is the potential lack of energy, since hydro is constrained by weather patterns and subsequent stream flows. The amount of energy available at a particular plant depends on its location and characteristics of its river system.

This IRP relies on information provided by the Northwest Power Pool (NWPP) to model regional hydro resources. The NWPP maintains a hydrological model providing energy amounts that each hydroelectric plant could produce from 1928 to 1999. This plan uses the 2004-05 Headwater Benefits Study. To accurately model British Columbian hydro projects, historical generation data from the Canadian Government was blended with the NWPP data set.

Many of the analyses in this IRP use an average of the 70-year record; stochastic studies randomly draw from the 70-year record (see stochastic modeling). Hydroelectric plants are lumped into geographic regions and represented as a single plant in each zone. The company models its Clark Fork, Spokane and Mid-Columbia projects to extract greater detail for portfolio modeling.

AURORAxmp represents hydro plants using annual and monthly information regarding energy generating capabilities, minimum and maximum generation levels, and abilities to sustain peak generating levels. The model's objective, subject to the constraints, is to move hydro generation into peak hours to follow daily load increases. This maximizes the value of the hydro system in a manner that approximates actual operations.

FUEL PRICES

The IRP uses fuel price assumptions in the most up-to-date EPIS database, with the exception of natural gas and coal prices. The price of fuel is the single most important modeling assumption in AURORAxmp. Natural gas sets the market price of power in the Northwest about three-quarters of the year and in more hours in other areas of the WI. Coal generally sets market prices during the spring when significant hydroelectric generation pushes natural gas-fired plants off of the margin.

NATURAL GAS PRICES

Avista retains several consultants who specialize in developing long- and short-term, fundamentals-based natural gas price forecasts. The company also reviews the Energy Information Association's Annual Energy Outlook (AEO) and monitors and participates in the New York Mercantile Exchange (NYMEX) forward natural gas price market. Each of these price curves uses different assumptions and provides the company with additional data about natural gas pricing.

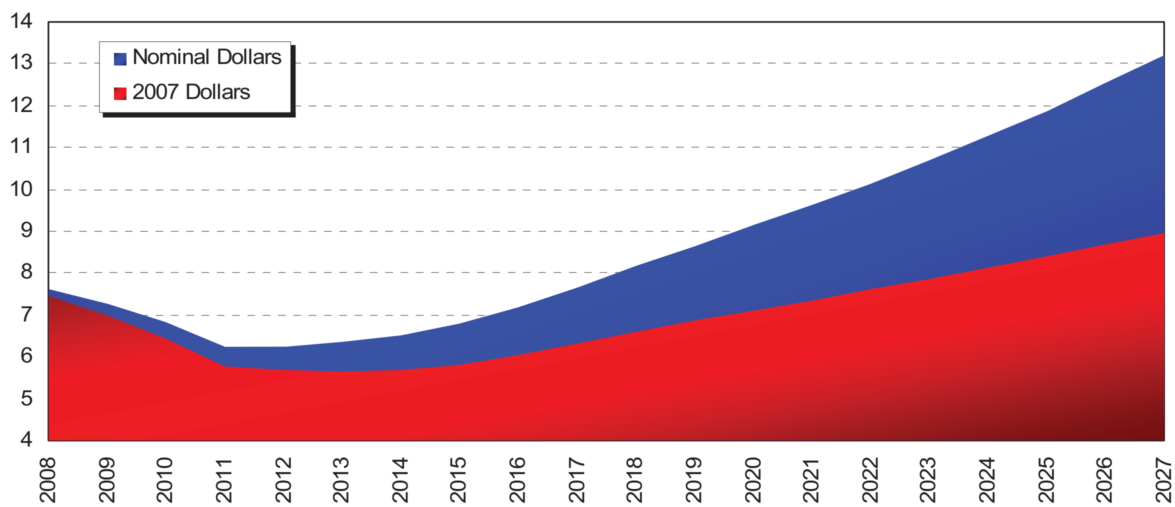
A multitude of factors were considered before choosing a price forecast. These factors included assumptions for economic growth, natural gas production levels, new infrastructure (i.e. Mackenzie Delta and Alaskan Pipelines), Canadian imports and demand (i.e. residential, commercial, industrial and electric generation). In particular, the selected consultant's forecast included more reasonable electric generation demand, liquid natural gas (LNG) imports, and overall natural gas supply and demand balance assumptions than the other price forecasts.

The natural gas price forecast provides annual average prices per decatherm at the Henry Hub basin in Louisiana. Annual average prices are converted into a series of monthly values before being entered into AURORAxmp. The monthly shape is based on NYMEX forward prices, which is consistent with Avista's 2006 Natural Gas IRP. Table 6.2 presents seasonal natural gas price factors. Monthly price shapes are derived by

Table 6.2: Seasonal Natural Gas Price Factors

Month	Percent of Annual	Month	Percent of Annual
January	113	July	93
February	113	August	94
March	110	September	95
April	93	October	96
May	92	November	101
June	92	December	106

Figure 6.3: Henry Hub Natural Gas Forecast ($/Dth)



applying these percentages to annual average prices. This approach reasonably reflects the actual seasonal weighting in the natural gas market.

The natural gas price forecast blended the January 3, 2007, NYMEX forward price with the consultant's price forecast. Blending the two prices acknowledges that the forward market is the price which can be currently purchased and that forward and fundamental prices should converge in the long-run. The weighting of the NYMEX forward price begins at 50 percent in 2008 and is decreased by 10 percent annually through 2012. The Henry Hub price forecast is shown in Figure 6.3.

Avista has historically used monthly natural gas prices in its IRP forecasts, but natural gas prices vary daily. This IRP is our first to include a daily adjustment from the monthly price forecast. Daily prices are calculated using 2003 to 2006 historical prices to determine a daily percent change from the monthly average price. This percentage is applied to the monthly price. Figure 6.4 illustrates the variability of daily natural gas prices around the monthly averages.

The final component of a natural gas price forecast is development of basis differentials from Henry Hub. Henry Hub is a trading point in Louisiana on the Gulf of Mexico, widely recognized as the most important natural gas pricing point in the United States. Henry Hub holds this distinction because of its spot and forward market trading volumes and its proximity to a large portion of U.S. natural gas production. NYMEX uses Henry Hub as a trading hub for futures contracts. All other production and market pricing points can be traded with a "basis differential" on the Henry Hub. The Western U.S. does not rely on Henry Hub for its physical gas

Figure 6.4: Daily Natural Gas Prices Shape ($/Dth)

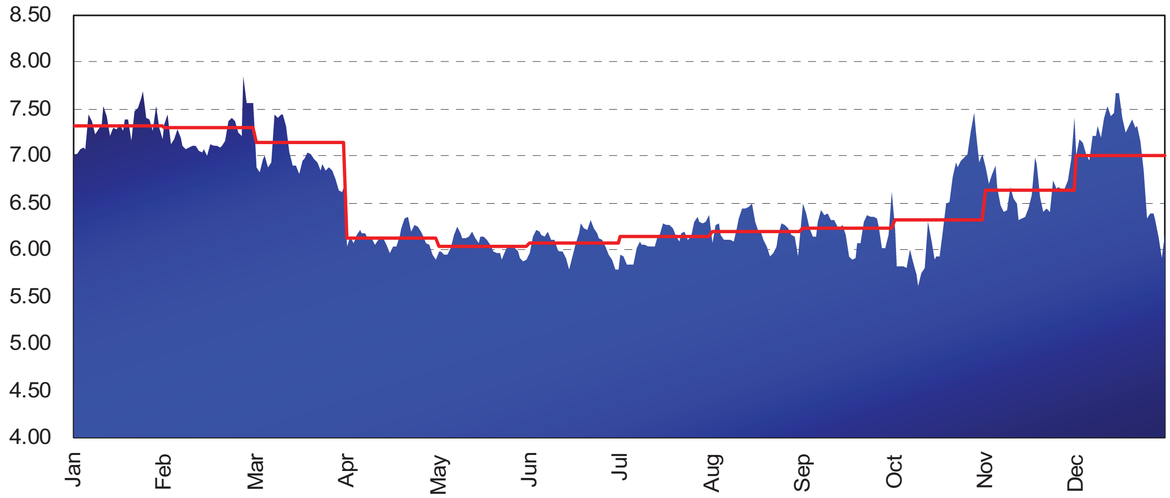


Table 6.3: Natural Gas Basin Prices as % of Henry Hub

Rockies	Sumas	AECO	Malin	Stanfield	Topock
83.1	86.1	85.1	88.3	86.9	89.5

deliveries. Instead it relies on physical supply points including AECO in Alberta, Canada, and the U.S. Rockies. Market trading hubs include Sumas, Wash.; Malin, Ore.; Stanfield, Ore.; and Topock, Calif. Natural gas at these supply points typically trade at a significant discount to Henry Hub. This discount is commonly referred to as the basis differential. Basis differentials exist because of a more favorable supply/demand balance in the West, closer physical proximity to these supplies and longer distances from the large natural gas demand centers of the Eastern U.S.

Most natural gas price forecasts do not include Northwest or Western U.S. pricing, so Avista estimates the basis differential between Henry Hub and the pricing points the company uses to fuel both its power plants and other plants across the Western Interconnect. The company uses an average of recent basis differentials to estimate price differences between the Henry Hub forecast and these markets. The company has adopted the percentages shown in Table 6.3, consistent with its 2006 Natural Gas IRP.

COAL PRICES

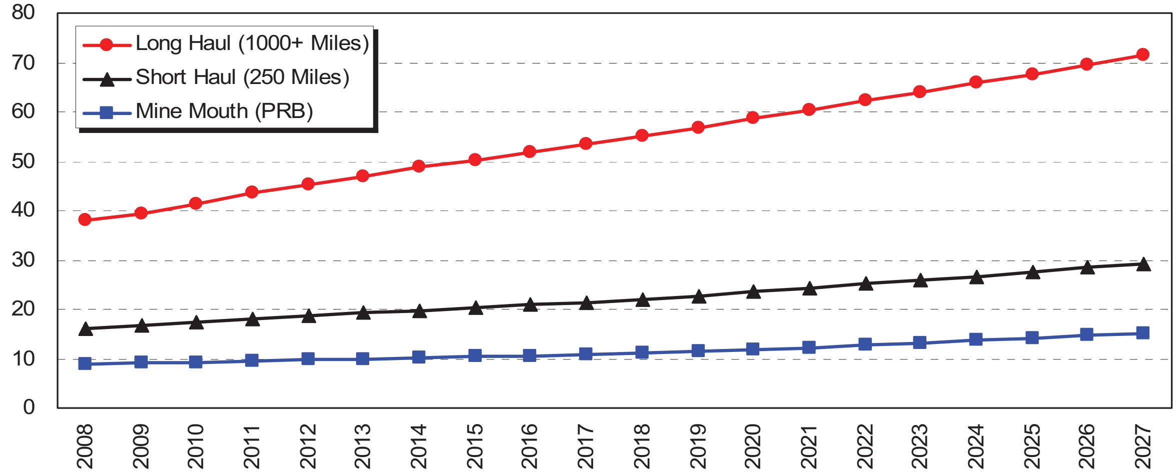
Coal prices and coal transportation costs in this IRP rely on data provided by the Energy Information Administration (EIA) in its February 2006 fuels forecast and its 2002 transportation cost study.[2] The IRP coal price for new coal-fired generation is based on the forecast of Western mine mouth coal prices. Transportation costs are added based on an assumed plant distance from its source of coal supply. This plan assumes three representative coal plant delivery distances for all plants: mine mouth, short haul (500 miles) and long haul (1,200 miles). Figure 6.5 shows the coal price forecast for new coal-fired resources options in the 2007 IRP. AURORAxmp contains coal price assumptions for existing coal-fired plants based on existing contracts. However, some plants also rely on market-based coal. These contracts are tied to the 2007 IRP coal price forecast.

EMISSIONS

Environmental factors are an increasingly important part of resource planning. Emission charges are used

[2] http://www.eia.doe.gov/cneaf/coal/ctrdb/tab55.html

Figure 6.5: Coal Prices for New Coal Resources ($/Ton)

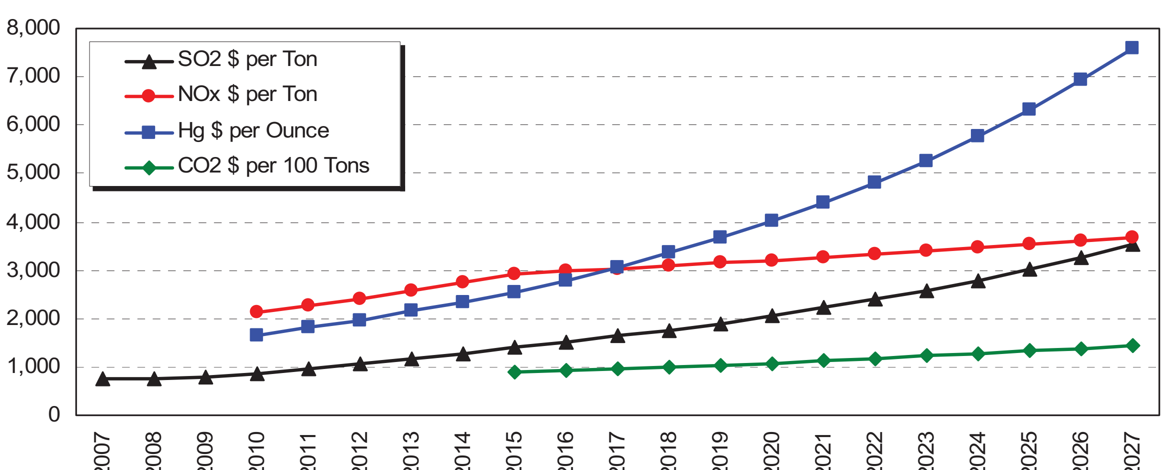


to encourage more environmentally-friendly resource options. The charge is calculated by estimating the financial penalty needed on certain types of emissions to accomplish a stated goal, such as reducing carbon emissions to 1990 levels. In the 2007 IRP, emissions charges are assigned to all resources to model the opportunity cost of generating and producing emissions or choosing not to generate and selling the right to produce emissions. This methodology implies that a cap-and-trade system is in place to trade emissions credits. Additional emissions discussions are located in Chapter 4.

The IRP tracks four emission types: carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrous oxygen compounds (NO_X), and mercury (Hg). CO_2 charges are estimated using the National Commission on Energy Policy (NCEP) carbon regulation proposal. There is currently a great deal of state and federal level legislation regarding carbon emissions which could significantly impact power prices. The uncertain state of carbon emissions legislation requires additional analysis to better understand the issues. This analysis is described in Chapter 7.

The remaining three emissions charges are estimated by a third-party consultant. Figure 6.6 shows the Base Case emission price forecasts. Emissions charges are set to a level necessary to cause existing plants to install mitigation equipment to reduce their average emissions

Figure 6.6: Emission Charges Summary



below certain thresholds. Emissions generally do not have a significant impact on electric market prices in Western U.S. markets because gas-fired plants usually set the marginal price of power. These plants have low overall emission profiles, with the exception of CO_2.

RESOURCES

The AURORAxmp model is populated with all current power generation resources and the operating characteristics important for modeling electricity markets (e.g., plant capacity, heat rate, and start-up costs). Resources under construction or otherwise expected to generate power in the future are also modeled. The AURORAxmp vendor has a rigorous plant data collection methodology that makes certain assumptions for each plant. The company has maintained many of these assumptions for the IRP model database but has made various changes where the company has access to better information. Resources not currently under construction, or a part of other companies' IRPs or plans, are modeled indirectly by two methods. The first method adds resources to meet future load growth for the West by using expansion logic in AURORAxmp; the second method adds generation needed to meet active or impending renewable portfolio standards (RPS). For example, Washington Initiative 937 requires all utilities with more than 25,000 customers to serve 15 percent of their 2020 load with new renewable resources.[3]

The AURORAxmp expansion logic used for this plan differs from the 2005 IRP. The 2005 plan built a level of generation across the West to meet the energy needs of the gross system. The 2007 IRP relies on a capacity planning target. In general, utilities build resources to cover adverse load conditions, meaning that resources are constructed to exceed average needs. This ensures that adequate resources are available to meet system requirements in all but the most extreme conditions, driving electric market prices and volatility down. The availability of firm resources to meet retail loads under a broad range of operating conditions reduces exposure to significant purchases of energy from the financially volatile short-term wholesale energy market.

The resources available to meet regional load growth are: combined-cycle combustion turbines (CCCTs), single-cycle combustion turbines (SCCTs), pulverized coal, integrated gasification combine-cycle (IGCC) coal, IGCC coal with sequestration (certain scenarios) and wind turbines. Other small renewable resource options are added using the RPS method discussed in the next paragraph. New resource options are limited depending on regional location and the presence of an active RPS in the region. For example, renewable resource construction in states with RPS requirements is limited by their RPS; no additional renewables are constructed. West coast states cannot rely on coal-fired plants due to legislative mandates preventing their construction. Detailed assumptions about these resources are discussed later in this section. Specific details on which resources were selected for each study are presented in Chapter 7. New resource options affect market prices which in turn affect the resource mix Avista will consider as it makes investment decisions over its planning horizon.

Renewable portfolio standards change the mix of resources utilities choose to build. Historically utilities built resources with the lowest expected future cost and rate volatility. RPS requirements and other legislative mandates have changed this approach. Utilities must build a specified amount of renewable resources or are limited in their ability to construct certain resource types. Resources procured under these circumstances may not be the lowest cost in a traditional sense, but they will meet a legislative mandate in one or more states and might reduce rate volatility where free or fixed fuel prices and fuel supply are available. Table 6.4 shows the incremental energy needed to meet existing renewable

[3] I-937 has earlier targets of 3 percent in 2012 and 9 percent in 2016.

Table 6.4: New RPS Resources Added to Existing System (aMW)

State	2010	2015	2020	2025
California	187	3,656	5,106	5,991
Oregon	0	519	914	1,867
Washington	0	328	988	1,260
Nevada	400	684	764	900
Montana	24	239	271	324
Arizona	187	556	1,113	1,964
Colorado	100	606	663	757
New Mexico	177	289	326	389

requirements in the Western Interconnect. Actual resources in each state will vary depending on how utilities choose to meet their requirements.

These additions represent company assumptions for the amount of renewable resources necessary to meet various state laws. In states where RPS laws were still pending at the time of the IRP modeling, we made our best estimate based on draft legislation.

A difficult part of forecasting renewable resources is determining where they will be located. Some states require utilities to acquire resources within certain geographic areas, which can greatly increase the price of those projects. New regional transmission may also be required. While recognizing that some regions will meet their RPS requirements by importing renewable power from other regions, the 2007 IRP assumes that all RPS resources are added in the geographic region where they are required. This simplifying assumption was based on the lack of a comprehensive study of regional renewable resource availability. The company does not believe that this simplifying assumption has any significant impact on the wholesale marketplace or the value of resource options available to it.

LOADS

A load forecast is developed for the entire region to forecast western electric prices. This IRP relies on several external sources to quantify load growth across the Western Interconnect. These sources include integrated resource plans, the Western Electricity Coordinating Council (WECC) and the Alberta Electric System Operator (AESO). Peak regional load growth is shown by area in Table 6.5. New resources are added to each area to meet capacity planning margins. The 2007

Table 6.5: Annual Average Peak Load Growth (%)

Area	Load Growth	Area	Load Growth
W. Wash.	1.40	California	2.50
W. Oregon[4]	1.40	Baja, Mexico	2.50
E. Wash.[5]	1.70	Wyoming	3.10
C. Oregon	0.90	Colorado	2.60
Montana	2.60	Utah	4.30
S. Idaho	2.60	Arizona	3.20
British Columbia	1.70	New Mexico	3.20
Alberta	2.10	Nevada[6]	3.10

[4] Southern Oregon is estimated to grow at 1.2 percent and Portland Metro Area is 2.6 percent.
[5] Spokane is estimated to grow at 2 percent, other eastern Washington areas 1 percent.
[6] Southern Nevada peak is expected to grow at 3.2 percent, while northern Nevada is at 2.6 percent.

Table 6.6: Annual Average Energy Load Growth (%)

Area	Load Growth	Area	Load Growth
W. Wash.	1.50	California	2.00
W. Oregon[7]	2.25	Baja, Mexico	2.00
E. Wash.[8]	1.57	Wyoming	2.80
C. Oregon	1.20	Colorado	2.00
Montana	2.50	Utah	3.30
S. Idaho	1.30	Arizona	2.50
British Columbia	1.40	New Mexico	2.50
Alberta	1.80	Nevada	2.50

IRP planning margins are assumed to be 25 percent for the Northwest and Idaho, 17 percent for California and 10 percent for all other zones.

Peak load growth estimates are important for estimating new capacity; however, market prices are more highly correlated to actual energy load growth. Energy growth estimates are shown in Table 6.6.

RISK MODELING

The power industry has fundamentally changed since the 2001 energy crisis. Historically, northwest utilities planned for variability inherent in their hydroelectric plants and load forecast. Now northwest utilities must consider natural gas price volatility, thermal plant forced outages, wind speed, extra-regional load and resource balances, and the ever changing face of emissions legislation. This IRP utilizes a Base Case with an underlying set of assumptions to anchor the modeling effort. Several alternative scenarios and futures are modeled to provide information about what could happen in the electric market under different sets of assumptions. All of the modeling efforts are combined with the judgment of planners, senior management and members of the Technical Advisory Committee to develop a Preferred Resource Strategy used to guide company resource acquisitions.

The Base Case for this study uses average values for most estimates, such as hydro conditions, peak and energy loads growth, and gas prices. These key market drivers will probably not be average in every year, but instead will regress to average levels over the 20-year planning horizon. Scenarios and stochastic studies help the company understand how the market might look and behave if the long-term averages in the Base Case did not materialize. This section focuses on the stochastic assumptions for these studies. The IRP models include several key assumptions that are modeled stochastically, including natural gas, hydro, load, wind, forced outages, and emissions charges (SO_2, NO_X, Hg and CO_2).
The 2007 IRP simulates 300 hourly iterations or "games," using the AURORAxmp for the years 2008-2027. This level of analysis required the use of 25 computers writing their results to a SQL database. Each set of stochastic analysis took the equivalent of four days, or 2,160 computer hours, to complete. The company prepared four stochastic futures for the IRP, consuming 8,500 hours of central processing unit time and creating a 450 gigabyte SQL database.

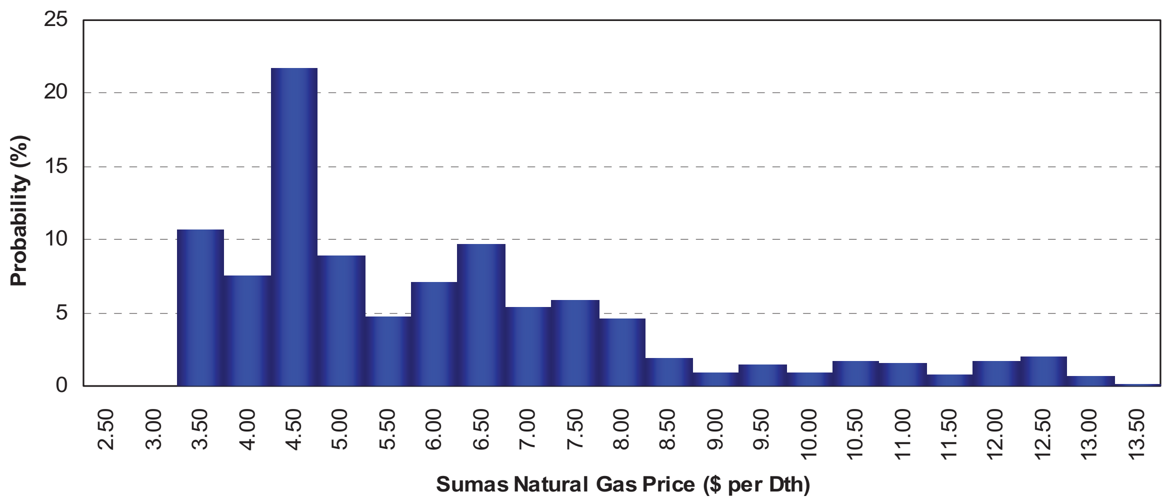
Running the electricity model stochastically provides a measure of volatility for forecasted electricity prices and resource values. This measure is essential to our selection of new resources, because the company's long-term objective is to manage rate variability, as well as limit customer costs.

[7] Southern Oregon is estimated to grow at 1.2 percent and Portland Metro Area is 2.6 percent.
[8] Spokane is estimated to grow at 2 percent, other eastern Washington areas 1 percent.

Table 6.7: Coefficient of Variation of Forward Sumas Natural Gas Prices (%)

Month	2005	2006	2007	2008
January	21	39	22	22
February	22	39	22	22
March	22	39	22	23
April	21	35	20	19
May	23	34	20	19
June	23	34	20	19
July	23	34	20	20
August	24	33	20	20
September	26	33	20	20
October	30	33	21	21
November	36	37	20	20
December	37	39	21	21

Figure 6.7: March 2006 Sumas Natural Gas Contact Price Distribution



NATURAL GAS PRICES

There are several approaches for stochastically modeling natural gas prices, as well as a number of assumptions that need to be made. The 2007 IRP begins with the deterministic natural gas price forecast discussed earlier in this chapter. The forecast represents mean prices in each forecast period. Table 6.7 shows the coefficient of variation (the standard deviation divided by the mean value) of historically traded forward natural gas contracts for the months of 2005 through 2008. We believe that forward market price volatility is a reasonable indicator of future natural gas price volatility. The Base Case assumes 30 percent volatility to capture projected market risk. This assumption differs from the 2005 IRP, which instead represented natural gas volatility with a 50 percent coefficient of variation.

The Base Case distribution is assumed to be lognormal based on a statistical review of the forward price datasets. A review of historical data shows that a majority of the contracts have lognormal characteristics; Figure 6.7 presents the distribution of the March 2006 Sumas forward contract. The Monte Carlo model draws a gas price curve using the lognormal distribution, but each

Figure 6.8: 2008 Sumas Natural Gas Price (Deterministic & First 30 Draws)

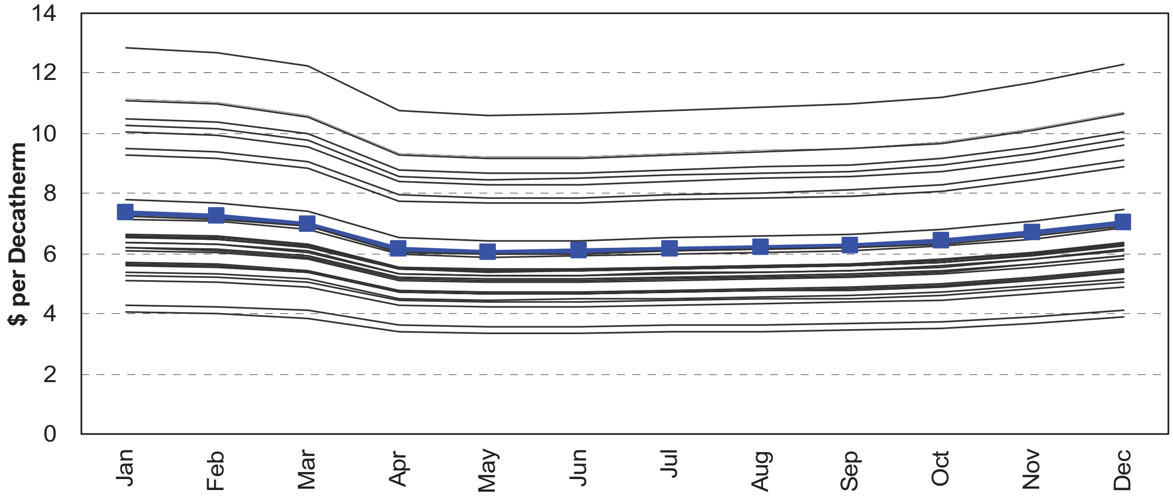


Figure 6.9: Annual Average of 300 Iterations of Sumas Natural Gas Prices ($/Dth)

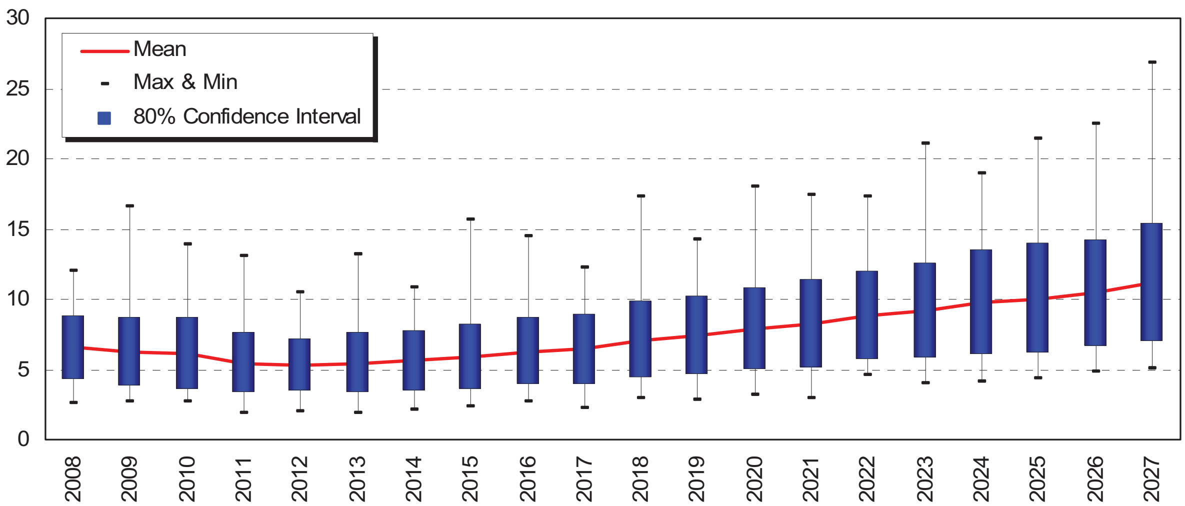


Figure 6.10: Hydro Capacity Factor and Statistics for Selected Areas (%)

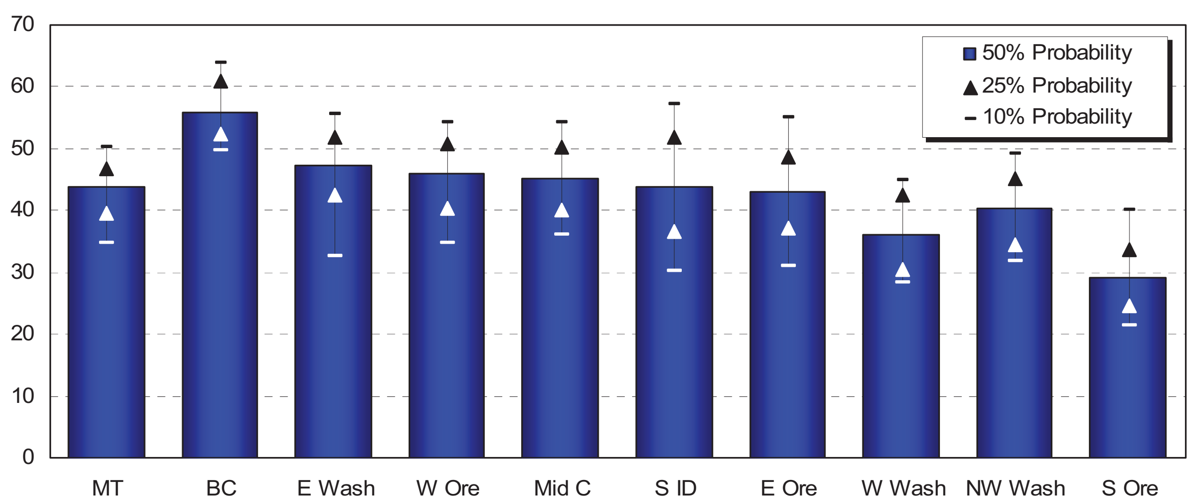


Figure 6.11: Water Year Distribution

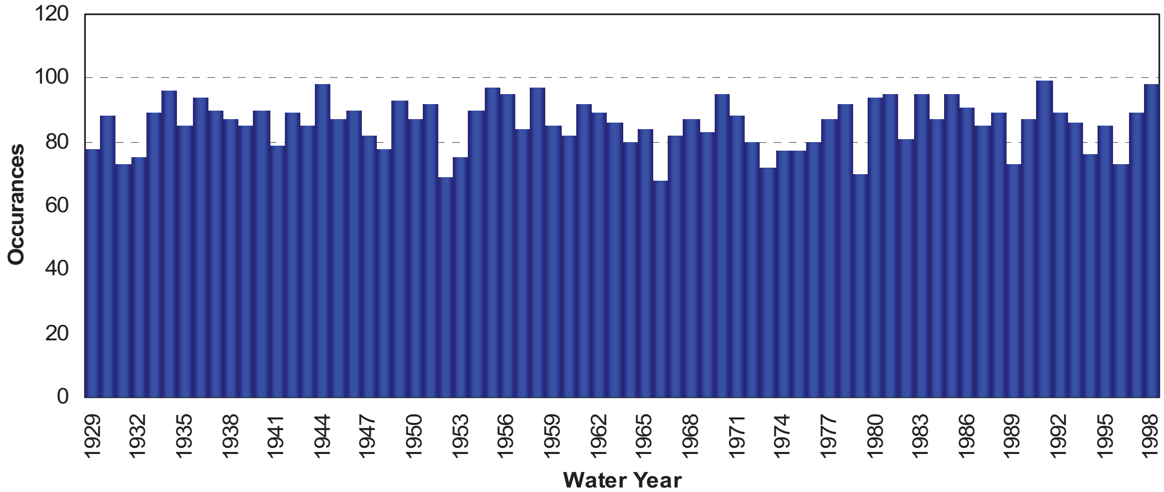
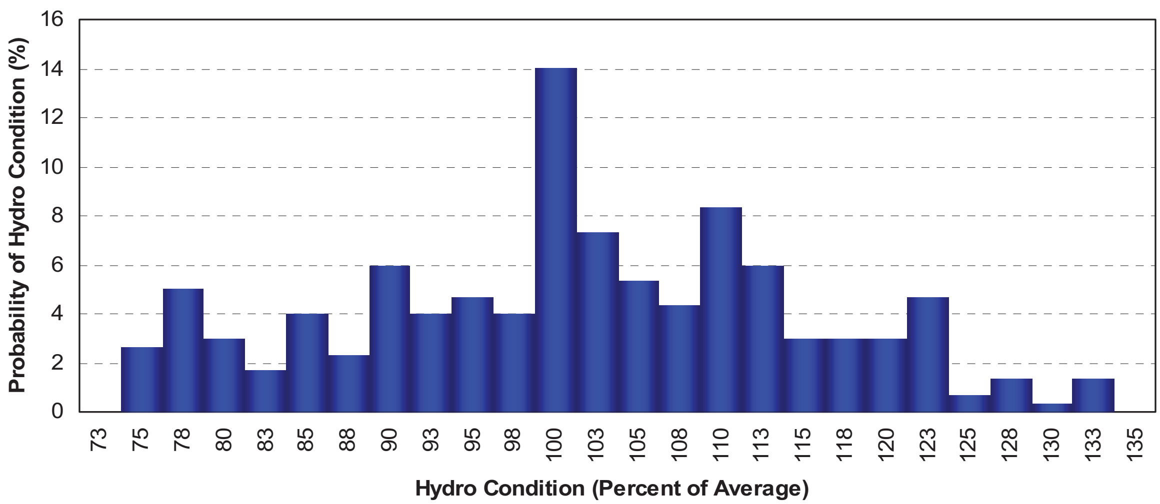


Figure 6.12: Distribution of Stochastic Hydro as a Percent of the Mean



draw has the same shape as the Base Case; the draw is either above or below the Base Case forecast. See Figure 6.8 for a graphical illustration.

Annual average results of this methodology are displayed in Figure 6.9. The chart shows the expected (deterministic) price, the mean of the 300 Monte Carlo iterations, the 80 percent confidence interval, and maximum and minimum prices.

HYDROELECTRIC GENERATION

The Northwest's electricity market, as well as the company's own resource portfolio, is significantly impacted by hydro generation. Figure 6.10 shows the hydro capacity factors assumed for zones and sub zones (areas) that have substantial hydro capacity.

To account for hydro variability, a random generator was used to select different hydro generation amounts for each year and for each of the 300 iterations. Hydro available in each draw was selected from 70 historical water years from 1928/29 to 1998/99. Figure 6.11 presents a distribution of the Base Case draws. The draws show a uniform distribution, or no bias, between water year selections.

Table 6.8: Selected Zone's Load Correlations to Eastern Washington (Jan-June)

Zone	Jan	Feb	Mar	Apr	May	Jun
Alberta	Not Sig	Not Sig	Mix	Mix	Mix	0.3270
Arizona	0.3504	0.3505	Mix	Mix	0.2027	0.4499
Baja	Not Sig	Not Sig	-0.2109	Not Sig	Mix	0.2171
British Columbia	0.7856	0.6762	0.8047	0.0997	0.1058	0.1089
Colorado	0.7852	0.4468	Mix	Mix	Not Sig	Mix
E. Oregon	0.9099	0.8822	0.8893	0.7400	0.4262	0.8613
Montana	0.8440	0.5508	0.8588	Not Sig	Not Sig	0.3487
N. California	Not Sig	Not Sig	Not Sig	Mix	Mix	Mix
N. Nevada	0.2456	0.3232	0.4272	Not Sig	0.1026	0.7609
New Mexico	Not Sig	Mix	Mix	Mix	Not Sig	Mix
S. California	0.1991	Not Sig	Not Sig	Mix	Mix	Mix
S. Idaho	0.6807	0.7163	0.6042	0.3317	0.2114	0.7373
S. Nevada	0.8003	0.3343	Not Sig	Mix	Mix	0.0968
Utah	0.8988	0.8770	0.8435	0.7345	0.4246	0.8451
W. Oregon	0.8177	0.5723	0.8781	0.1043	Mix	0.3152
W. Washington	0.8284	0.4689	0.9031	0.1043	Mix	Mix
Wyoming	0.9089	0.9004	0.9300	0.6906	0.4186	0.5850

Table 6.9: Selected Zone's Load Correlations to Eastern Washington (July-Dec)

Zone	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	0.7575	0.1003	Not Sig	Not Sig	Not Sig	0.4306
Arizona	0.2134	Mix	Not Sig	Not Sig	Not Sig	0.4233
Baja	0.1999	0.3011	Mix	Not Sig	Mix	0.1100
British Columbia	0.6397	0.3084	Mix	0.6985	0.5887	0.8158
Colorado	Not Sig	Not Sig	Not Sig	Not Sig	Not Sig	0.3321
E. Oregon	0.7343	0.7871	0.5924	0.8831	0.8324	0.4573
Montana	0.8310	0.2095	0.2979	0.8342	0.8199	0.8107
N. California	0.4874	Mix	Mix	Not Sig	0.2096	0.2104
N. Nevada	0.6583	0.2339	0.5424	Not Sig	0.1029	0.7235
New Mexico	Not Sig	Mix	Not Sig	Not Sig	0.1036	Not Sig
S. California	0.5017	0.1044	Mix	Not Sig	0.2025	0.2284
S. Idaho	0.2093	0.6807	0.7406	0.2317	0.8991	0.4475
S. Nevada	Not Sig	Mix	0.3208	Not Sig	0.1020	0.6617
Utah	0.6201	0.7815	0.8238	0.8590	0.8515	0.5825
W. Oregon	0.8337	0.4289	0.4410	0.8547	0.5755	0.3413
W. Washington	0.8645	0.3171	Mix	0.8724	0.8854	0.4803
Wyoming	0.5902	0.3100	0.6721	0.8919	0.8685	0.3487

The historical water record's distribution is shown in Figure 6.12. Generation is shown as a percent of the mean for the entire Northwest, encompassing British Columbia, Washington, Oregon, Idaho and Montana.

LOAD VARIABILITY

The 2007 IRP relies on Western Interconnect-wide methodology developed for the 2003 IRP. The earlier work developed monthly and weekly distributions of hourly load data for each Western Interconnect utility using FERC Form 714 data. The 2007 IRP updates the 2003 data, using FERC Form 714 data for the years 2002-2005. Correlations between the Northwest and other Western Interconnect load areas were calculated

Table 6.10: Selected Zone's Load Coefficient of Variation (Jan-Jun %)

Zone	Jan	Feb	Mar	Apr	May	Jun
Alberta	2.9	2.5	3.3	3.2	2.7	4.0
Arizona	5.2	5.6	4.8	6.7	11.0	6.3
Baja	10.0	8.2	9.4	9.9	10.9	6.7
British Columbia	5.4	3.9	5.6	4.7	4.6	4.5
Colorado	4.9	5.2	5.4	5.0	7.7	6.9
S. Idaho	5.3	5.6	7.1	6.1	9.9	8.3
LADWP	7.2	7.2	7.3	8.3	10.1	8.2
Montana	4.9	4.8	5.6	4.8	5.5	5.3
W. Montana	4.9	4.8	5.6	4.8	5.5	5.3
New Mexico	4.6	4.9	4.6	4.8	6.9	4.8
N. Nevada	3.0	2.7	3.5	3.7	5.3	4.7
S. Nevada	3.7	4.1	4.1	6.4	13.9	8.4
E. Washington	6.6	5.4	6.9	5.5	5.6	7.3
W. Washington	7.5	5.8	7.1	5.7	6.3	5.2
E. Oregon	5.1	4.9	5.8	5.4	6.6	6.4
W. Oregon	7.4	6.0	6.9	6.3	6.6	7.8
N. California	5.4	5.5	5.7	6.5	9.2	9.5
S. California	7.3	7.2	7.2	8.1	10.0	8.1
Utah	5.1	5.1	5.9	5.4	6.9	6.5
Wyoming	5.2	5.0	5.8	5.3	6.4	6.4
C. California	5.4	5.6	5.8	6.5	8.8	9.0

Table 6.11: Selected Zone's Load Coefficient of Variation (July-Dec %)

Zone	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	3.8	3.3	2.9	2.9	2.4	3.0
Arizona	6.5	7.6	10.2	9.5	4.5	6.2
Baja	6.4	6.2	9.7	9.3	7.7	10.6
British Columbia	4.9	4.9	4.4	5.5	4.7	4.2
Colorado	7.8	7.2	7.2	5.3	5.1	5.0
S. Idaho	6.2	7.5	7.8	4.9	5.4	5.1
LADWP	9.3	8.0	9.7	8.1	7.7	7.1
Montana	6.4	5.3	4.6	5.2	4.7	4.1
W. Montana	6.4	5.3	4.6	5.2	4.7	4.1
New Mexico	6.0	5.8	6.4	5.0	4.8	5.0
N. Nevada	4.7	5.1	4.7	3.1	3.1	3.5
S. Nevada	6.8	8.2	10.0	9.1	4.1	4.3
E. Washington	7.1	6.9	5.7	6.1	5.9	4.9
W. Washington	6.5	5.6	4.9	6.8	6.2	5.1
E. Oregon	6.0	6.2	6.3	5.2	5.0	4.8
W. Oregon	9.6	8.4	7.2	6.6	6.0	5.5
N. California	8.9	8.0	9.3	6.7	5.9	5.9
S. California	9.2	7.8	9.7	8.2	7.8	7.2
Utah	5.9	6.3	6.5	5.2	5.1	4.8
Wyoming	6.1	6.0	6.2	5.3	5.2	5.0
C. California	8.7	7.7	9.0	6.7	6.0	6.1

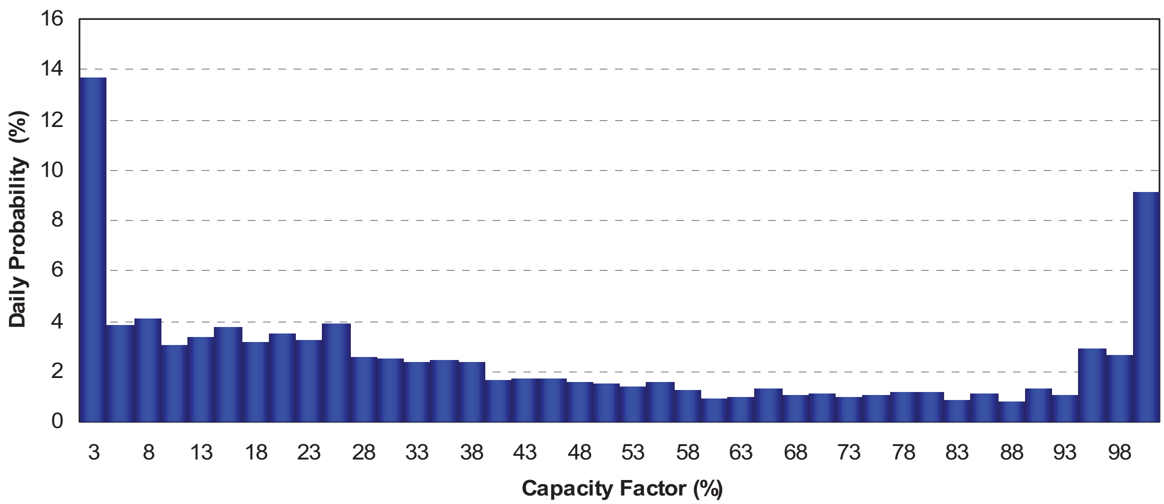
and represented in the stochastic load model. Correlating zone loads avoids oversimplifying the Western Interconnect load picture. Absent correlation data, stochastic models would offset load changes in one zone with load changes in another, thereby virtually eliminating the possibility of modeling West-wide load excursions. Given the high degree of interdependency across the Western Interconnect (e.g., the Northwest and California), this additional accuracy is crucial for understanding variation in wholesale electricity market prices.

Tables 6.8 and 6.9 illustrate the correlations used for the 2007 IRP. Tables 6.10 and 6.11 provide the coefficient of variation (standard deviation devided by the mean) for each zone in 2007. "NotSig" indicates that no statistically valid correlation was found in the evaluated data. "Mix" indicates that the relationship was not consistent across time and was not used in the 2007 IRP analysis.

WIND GENERATION

Wind is one of the most volatile energy resources available to utilities. Since storage, apart from some integration with hydro, is not a financially viable option, capturing the resource's volatility in the power supply model is necessary to correctly determine its impacts on the overall market as well as the value of any acquisition. Accurately modeling a wind resource requires hourly generation shapes. For regional analyses, wind variability is modeled in a manner similar to how AURORAxmp models hydroelectric resources. A single wind plant and generation shape is developed for each area. This generation shape is smoother than individual plant characteristics, but closely represents how a large number of wind farms across a geographical area would operate together.

Figure 6.13: August Hourly Wind Generation Distribution



This simplified wind methodology works well for forecasting electricity prices across a large market, but it does not represent the volatility of specific wind resources that the company might select. A different wind shape was used for each company resource option in each of the 300 Monte Carlo iterations. This analysis uses historical wind data for potential wind sites in the Columbia Basin and eastern Montana. A statistical analysis of the wind data showed that a wind plant would either generally be at or near full output or at no generation most of the time. This U-shaped or beta general distribution is shown in Figure 6.13. This shape demonstrates that a wind plant with an annual average 33 percent capacity factor rarely produces energy at this

Figure 6.14: Actual Stateline Generation August 9th Through 15th, 2006

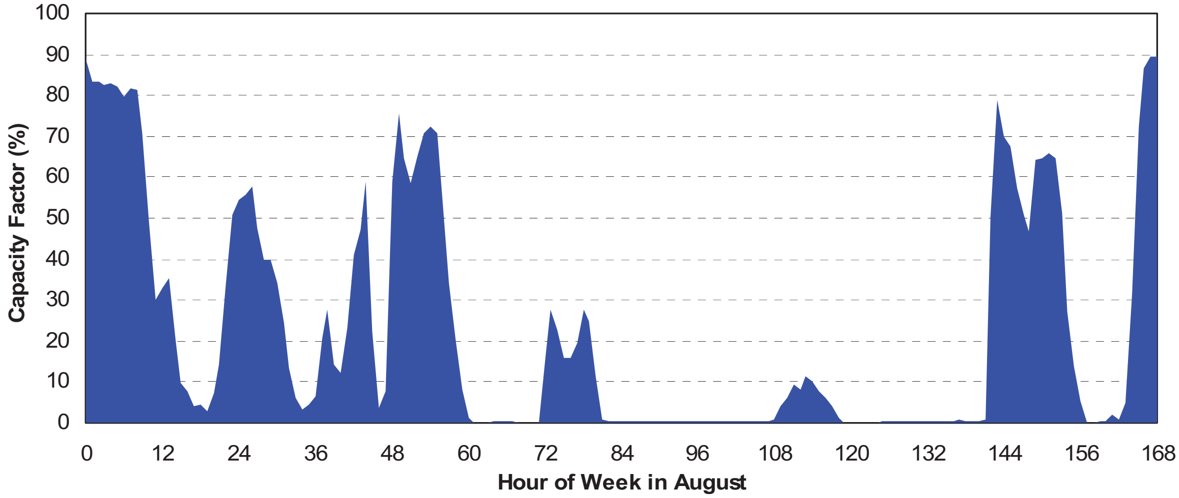


Figure 6.15: Simulated Hourly Columbia Basin Wind Generation for August

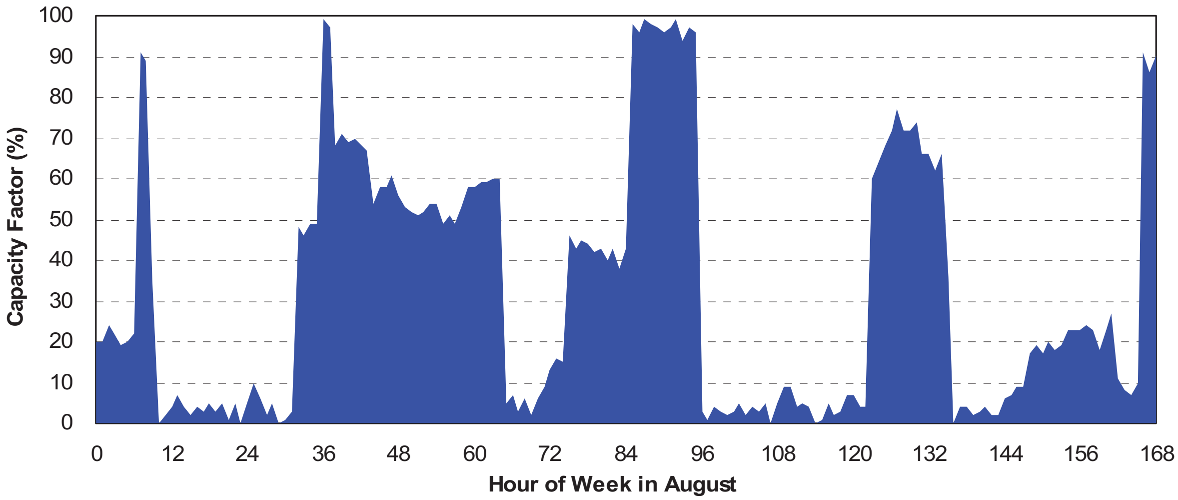


Table 6.12: Simulated Average Annual Wind Capacity Factors (%)[9]

	Columbia Basin	Montana
Mean	33.3%	38.8%
80% Confidence Interval (High)	30.4%	35.9%
80% Confidence Interval (Low)	36.3%	41.6%

level for a specific period of time but does so over an extended period.

The Monte Carlo model randomly draws a capacity factor from the distribution for each hour of each month. This method creates probabilities for good, average and poor wind years. Serial correlation between hours ensures that the hour-to-hour wind generation relationship is retained, preventing an entirely random wind generation profile. Figure 6.14 presents actual Stateline generation from August 2006. The forecast does not try to replicate historical wind data; instead it tries to maintain the underlying statistics of the wind patterns. The Stateline data never reaches 100 percent capacity

[9] Includes losses and the mean of stochastic studies does not guarantee the expected value.

factor due to maintenance and forced outages. The simulated data in Figure 6.15 includes maintenance and forced outage normalized as part of the average capacity factor. Table 6.12 presents the average capacity factors for Columbia Basin and Montana wind sites, along with their modeled confidence interval.

FORCED OUTAGES

In the 2005 IRP, forced outages were modeled as de-rates to plant capacity because AURORAxmp was unable to integrate random forced outages with other stochastic inputs. The modeling software now has this capability. Forced outages are based on a rate and a mean time to repair. Over the 300 iterations forced outages average mean outage rate levels. The 2007 IRP models forced outages stochastically for all CCCT, coal and nuclear plants. These plants represent the marginal resources running during the majority of the modeled hours; they are of the most interest. Hydro, wind, SCCT and other renewables were not modeled stochastically.

EMISSIONS CHARGES

This IRP uses consultant forecasts for SO_2, NO_X and Hg emission costs based on current and projected national emissions policies. Certain state limits, particularly for Hg, make emissions modeling problematic at best. The Base Case emission prices described earlier represent the mean values for each emission. History shows that emission costs vary depending on market conditions. For stochastic analysis, each emission price was assumed to have a 20 percent standard deviation.

Greenhouse gases, or CO_2, emission prices were selected for each iteration by using a probability of different price levels because of the greater uncertainty of pending state and federal regulation. Each iteration uses a different carbon emission charge. Table 6.13 shows the probability distribution of CO_2 emissions.

NEW RESOURCE ALTERNATIVES

This section describes each of the resource alternatives considered in the model to meet Avista's future resource deficits. These resources reflect generic options that might differ from actual projects for a variety of siting or engineering reasons. Actual characteristics and assumptions will likely be developed through a Request for Proposal (RFP) process.

COMBINED-CYCLE COMBUSTION TURBINES (CCCT)

Combined-cycle combustion turbines are modeled using a two-on-one configuration. This configuration consists of two gas turbines using a single heat recovery steam generator (HRSG), rather than one gas turbine matched with a HRSG. These plants generally range between 200 and 600 MW. Capital cost estimates are based on a 280 MW 7FA General Electric (GE) machine. Operation and maintenance costs are based on estimates from the Northwest Power and Conservation Council (NPCC), adjusted for inflation.

The heat rate modeled for this resource begins at 6,722 Btu/kWh in 2008 and decreases by 0.5 percent each year to account for technological improvements.

Table 6.13: Probability Matrix of Carbon "Taxes" ($/Ton)

Probability	Tax Amount (2015)	Tax Amount (2025)
10.0%	0.00	0.00
1.5%	1.76	2.66
15.0%	6.60	9.96
50.0%	8.80	13.28
15.0%	11.00	16.60
2.0%	15.84	23.90
5.0%	16.50	30.00
1.5%	33.00	60.00

Figure 6.16: Capacity Levels for Northwest Gas-Fired Plants (%)

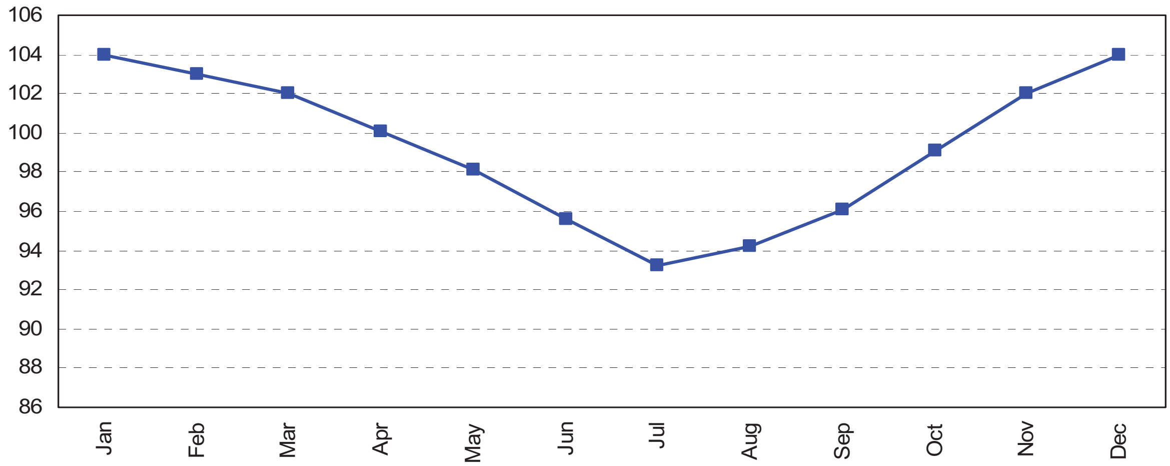


Table 6.14: Real 2007 Levelized Costs for 2013 CCCT (Full Availability)

Item	$/MWh
Fuel Cost	47.17
VOM	2.71
Fixed O&M	1.15
Non-Capital Transmission	0.00
Emissions	3.31
Generation Capital Recovery and Overheads	9.50
Transmission Capital Recovery and Overheads	1.30
Value of Losses	0.00
Total	65.14

The plants are modeled so that 7.7 percent of the capability is for duct firing at a higher heat rate of 8,300 Btu/kWh. Forced outage rates are estimated as 5 percent per year; 14 days of maintenance will occur biennially. Cold startup costs are assumed to be $35 and 6.3 decatherms per megawatt per start.[10] CCCT plants are modeled to back down as far as 50 percent of their nameplate capacity and ramp from zero to full load in three hours. The maximum capability of each plant is highly dependent on temperature. Figure 6.16 illustrates the average capacity by month for a Northwest CCCT relative to its nameplate rating.

No limitations were placed on the number of CCCTs that could be selected for any area.
CCCT Resource Capital and Operating Costs (2007$):

- Capital Cost: $786 per kW
- Fixed O&M: $9.40 per kW-yr

SIMPLE-CYCLE COMBUSTION TURBINES (SCCT)

The 2005 IRP includes two simple-cycle combustion turbine options: Frame (GE 7EA) and aero-derivative (GE LMS 100) machines. Aero-derivative plants can ramp up quickly and have low heat rates and start-up costs, but their upfront costs are significantly higher than frame units. Operations and maintenance costs are based on inflation-adjusted NPCC estimates.

The heat rates for SCCT plants are 8,910 Btu/kWh (Aero) and 10,139 Btu/kWh (Frame) in 2008, decreasing by 0.5 percent each year to account for technological improvements. Forced outage rates are estimated at 3.6

[10] For example, a 250MW plant would cost $18,987.50 to start up: $8,750 ($35 * 250 MW) for O&M and $10,237.50 (6.3 Dth * 250 MW * $6.50/Dth) for fuel.

Table 6.15: Real 2007 Levelized Costs for 2013 SCCT (Full Availability)

Item	Aero ($/MWh)	Frame ($/MWh)
Fuel Cost	62.48	72.91
VOM	9.40	4.69
Fixed O&M	1.11	0.85
Non-Capital Transmission	0.00	0.00
Emissions	4.38	5.11
Generation Capital Recovery and Overheads	7.48	4.99
Transmission Capital Recovery and Overheads	0.67	0.67
Value of Losses	0.00	0.00
Total	**85.52**	**89.22**

percent per year, with no modeled maintenance outages (maintenance will occur in shoulder months where these plants do not operate). Cold startup costs were not modeled. The maximum capabilities of these plants are highly dependent on temperature conditions and are assumed to have the shape as CCCT plants, see Table 6.15. No limits were placed on SCCT construction.

SCCT Resource Capital and Operating Costs (2007$):

- Capital Cost: $628 per kW for Aero, $419 per kW for Frame
- Fixed O&M: $9.16 per kW/yr for Aero, $7.05 per kW-yr for Frame

COAL PLANTS

As identified in the 2005 IRP as an action item, in 2005 and 2006 Avista partnered with Idaho Power to analyze coal plant costs. After the consultant study was complete, a Request for Qualifications (RFQ) was issued to learn about coal projects currently in the development pipeline. The RFQ identified projects in Washington, Idaho, Montana, Utah, Wyoming and Nevada. Each project's cost and non-cost factors were studied. As a result of this effort, combined with recent legislative mandates, Avista has decided that it will no longer pursue a new coal-fired plant. The resource however, does warrant review in the 2007 IRP.

Two main types of coal plants were studied: pulverized and IGCC. Pulverized options are sub-critical, super-critical, ultra-critical and circulating fluidized bed (CFB). These different technologies have different boiler temperatures and pressures, resulting in different capital cost and operating efficiencies. IGCC plants may include a back-up coal gasifier and/or a carbon sequestration option.

The market studies limited coal plant construction to the Rocky Mountains, Canada and the Desert Southwest. Plants built in these areas were not allowed to serve loads

Table 6.16: Coal Plant Technology Characteristics and Assumed Costs

Technology	Plant Sizes (MW)	Heat Rate (Btu/kWh)	Capital Cost (2007$)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Forced Outage (%)
Sub-critical	175-1000	9,371	1,905	44.57	3.91	6
Super-critical	375-1000	8,955	2,004	45.50	3.86	6
Ultra-critical	600-1000	8,825	2,010	46.55	3.90	6
CFB	50-425	9,289	2,155	48.43	6.15	6
IGCC	250-650	8,131	2,378	54.98	3.21	7 or 10[11]
IGCC w/ seq.	250-650	9,595	3,045	64.87	3.45	7 or 10

[11] Forced outage rate is lower if a spare gasifier is available.

Table 6.17: Regional Coal Transmission Capital Costs

Location	Capital Cost ($Millions)	Size (MW)	Cost ($/kW)
Northwest	500	1,000	500
Eastern Montana	1,000	1,000	1,000
Wyoming	3,000	2,000	1,500

Table 6.18: Real 2007 Levelized Costs for 2013 NW Coal Plants (Full Availability $/MWh)

Item	Sub-critical	Super-critical	Ultra-critical	CFB	IGCC[12]	IGCC w/ Seq[13]
Fuel Cost	26.19	25.03	24.67	25.96	22.73	27.90
VOM	3.98	3.94	3.97	6.27	3.19	3.40
Fixed O&M	5.62	5.74	5.88	6.11	7.06	8.33
Non-Capital Transmission	1.12	1.12	1.12	1.12	1.17	1.17
Emissions	10.85	10.36	10.21	11.83	8.97	2.21
Generation Capital Recovery and Overheads	24.34	25.59	25.67	27.52	31.71	42.17
Transmission Capital Recovery and Overheads	5.23	5.23	5.23	5.23	5.46	5.67
Value of Losses	0.68	0.68	0.68	0.68	0.68	0.82
Total	**78.02**	**77.70**	**77.43**	**84.73**	**80.97**	**91.68**

in other Western Interconnect areas. This plan assumes that a new coal plant could not be constructed until 2013 at the earliest.

The various coal plant technologies each have unique characteristics. Table 6.16 illustrates some of these key operational and cost differences between them.

TRANSMISSION ESTIMATES:

Coal plant costs are highly dependent on the amount of transmission necessary to bring their power to load centers. Estimating transmission costs in regions outside of the Northwest is difficult, as we are not as familiar with the unique challenges faced by transmission planners in those regions. Even with good transmission cost estimates, the method for cost allocation is unknown. The 2007 IRP relies heavily on other studies for estimating transmission costs. Table 6.17 illustrates the transmission costs assumed for the 2007 IRP. Table 6.18 presents the 2007 real levelized costs of the various coal plant technologies.

WIND

Concerns over carbon-based generation technologies' impacts on the environment have greatly increased the demand for wind generation. Governments, through tax credits, renewable portfolio standards and eminent carbon caps are also promoting development. Wind is currently the major renewable resource with commercial-scale development potential. Strong demand has increased the price of acquiring these assets by about 70 percent since the 2005 IRP.

Three wind resource locations were studied: Columbia Basin, Montana and plants within Avista's service territory. Each location has a capacity factor and transmission cost. All locations were assumed to have the same capital cost.

TRANSMISSION ESTIMATES:

- Columbia Basin: BPA wheel and $50 per kW for local interconnection
- Montana: Northwestern wheel and $50 per kW

[12] A spare gasifier is not included.
[13] This assumes that a plant is built without a spare gasifier in 2018 or later.

Table 6.19: Wind Location Capacity Factors (Excludes Losses)

Location	Capacity Factor
Columbia Basin Tier 1	33.2%
Columbia Basin Tier 2	27.7%
Montana Tier 1	40.8%
Montana Tier 2	32.7%
Avista Service Territory Tier 1	30.0%
Avista Service Territory Tier 2	21.7%

Table 6.20: Wind Integration Costs[14]

Wind Location	Wind Capacity (MW)	System Penetration	$/MWh
Columbia Basin	100	5%	2.75
50/50 Mix CB & MT	200	10%	6.99
Diversified Mix	400	20%	6.65
Diversified Mix	600	30%	8.84

for local interconnection

- Avista Service Territory: No wheel and $30-130 per kW for interconnection; it is likely to be cheaper to integrate a tier 2 wind site than a tier 1 site to Avista due to the distance of existing transmission
- BPA wheel: $16.90 per kW-yr
- BPA losses are 1.9 percent
- Northwestern wheel: $40.80 per kW-yr
- Northwestern losses are 4.0 percent
- No losses or wheel on Avista system

Each regional wind area is modeled with two capacity factor levels: tier 1 and tier 2. Tier 2 wind has a 20

Table 6.21: Real 2007 Levelized Costs for 2013 Wind Plants (Full Availability)

Item	Columbia Basin Tier 1 ($/MWh)	Columbia Basin Tier 2 ($/MWh)	Montana Tier 1 ($/MWh)	Montana Tier 2 ($/MWh)	Avista Service Territory Tier 1 ($/MWh)	Avista Service Territory Tier 2 ($/MWh)
Fuel Cost	0.00	0.00	0.00	0.00	0.00	0.00
VOM and Integration	4.67	4.67	6.38	6.38	4.58	4.58
Fixed O&M	7.49	9.00	6.23	7.78	8.14	11.25
Non-Capital Transmission	7.19	8.64	14.53	18.13	0.00	0.00
Emissions Taxes	0.00	0.00	0.00	0.00	0.00	0.00
Generation Capital Recovery and Overheads	55.22	68.43	46.89	62.25	63.29	87.50
Transmission Capital Recovery and Overheads	1.45	1.74	1.21	1.51	4.10	1.31[15]
Value of Losses	0.83	0.83	1.78	1.78	0.00	0.00
Total	**76.84**	**77.02**	**93.30**	**97.82**	**80.12**	**104.64**

[14] See http://www.avistautilities.com/resources/plans/documents/AvistaWindIntegrationStudy.pdf

[15] Transmission estimates near Tier 2 wind sites in Avista's service territory tend to be lower than higher capacity factor wind sites due to the proximity of transmission lines.

percent lower capacity factor than tier 1 wind. The capacity factors in Table 6.19 are mean values for each region; a statistical method based on regional wind studies was used to arrive at a range of capacity factors depending on the wind regime in each year. Table 6.21 presents the 2007 real levelized costs of the various wind plant locations.

Capital and Operating Costs (2007$):

- Capital Cost: $1,884 per kW,
- Fixed O&M: $17.50 per kW-yr,
- Variable O&M: $1.00 per MWh and
- Wind Integration Costs: see Table 6.20.

ALBERTA OIL SANDS

Alberta Oil Sands are potentially an attractive co-generation resource option for the United States and Canada. It must overcome the significant transmission investment required to transport generated power to the Northwest. It also requires a partnership between oil and utility firms to make the project viable. For all of the discussion around this resource, cost and operating data is hard to come by.

Transmission for this project has been extensively studied by the Northwest Transmission Assessment Committee (NTAC) Discussed below are the assumptions used for modeling the Oil Sands as a resource option for the 2007 IRP.

OIL SANDS TRANSMISSION ESTIMATES (PRIMARILY FROM NTAC):

- DC Line: $1,365,433,000
- Terminals: $500,000,000
- Communications: $30,000,000
- Total Transmission Capital Cost: $1,895,433,000
- Capital Cost: $3,963 $/kW (2007$)
- Transmission O&M: $8.90 per kW-yr
- BPA wheel: $16.90 per kW-yr
- Losses are expected to be 7.7 percent to Celilo and 1.9 percent back to Spokane

OIL SANDS RESOURCE

The heat rate of this resource is modeled at 5,000 Btu/kWh. This rate allocates potential emission and fuel costs to the utility.[16] The resource would probably have a gasifier to transform the residual oil to synthetic gas and a combustion turbine to generate steam for the oil recovery process. The fuel price equals the fixed and operating costs of the gasifier.

An IGCC plant designed for coal gasification is a similar resource to Alberta Oil Sands because both require gasification and the use of a combustion turbine unit. Given a lack of good price information on this resource, we base our estimate on an IGCC plant capital cost of $2,378 per kW. As one-third of the plant's heat value is for electric generation, only that portion is applied to

Table 6.22: Real 2007 Levelized Costs for 2013 Alberta Oil Sands Project (Full Availability)

Item	$/MWh
Fuel Cost	0.00
VOM	3.55
Fixed O&M	7.45
Non-Capital Transmission	3.48
Emissions Taxes	4.85
Generation Capital Recovery and Overheads	53.34
Transmission Capital Recovery and Overheads	14.20
Value of Losses	3.70
Total	**91.58**

[16] The IRP assumes no fuel costs, but arrangements could have a fuel charge.

the electricity side of the operation. To this cost a heat-recovery steam generator is added, bringing the total plant cost to $3,963 per kW.

Operation and maintenance costs are assumed to be similar to that of an IGCC plant. Fixed O&M is modeled at $55 per kW-yr and $3.00 per MWh. The forced outage rate is assumed to be 5 percent, and planned maintenance occurs biennially for 21 days. Table 6.22 presents the 2007 real levelized costs of the Alberta Oil Sands resource.

OTHER MODELED RESOURCES

A number of other resource options are modeled in this IRP. These include biomass, geothermal, small cogeneration and nuclear. Nuclear plants are not currently considered as a resource option to Avista, but, like coal plants, need to be studied for each plan because they are an option to other areas of the Western Interconnect. Over time, this could change as national policy priorities focus attention on de-carbonizing energy supply. Nuclear capital costs are difficult to determine, as a new nuclear project has not been built in the U.S. in more than 25 years. Better nuclear cost

Table 6.23: Real 2007 Levelized Costs for Other Resources (Full Availability)

Item	Biomass ($/MWh)	Geo-thermal ($/MWh)	Small Co-Gen ($/MWh)	Nuclear ($/MWh)
Fuel Cost	0.00	0.00	33.48	8.06
VOM	6.88	6.88	2.55	5.63
Fixed O&M	5.34	11.03	1.09	7.11
Non-Capital Transmission	2.56	2.65	0.00	2.17
Emissions Taxes	0.00	0.00	2.38	0.00
Generation Capital Recovery and Overheads	51.30	43.13	24.56	42.81
Transmission Capital Recovery and Overheads	0.69	0.72	0.64	5.65
Value of Losses	0.83	0.83	-1.97	0.87
Total	**67.60**	**65.23**	**62.72**	**72.30**

Figure 6.17: Real Levelized Costs for Selected Resources at Full Availability ($/MWh)

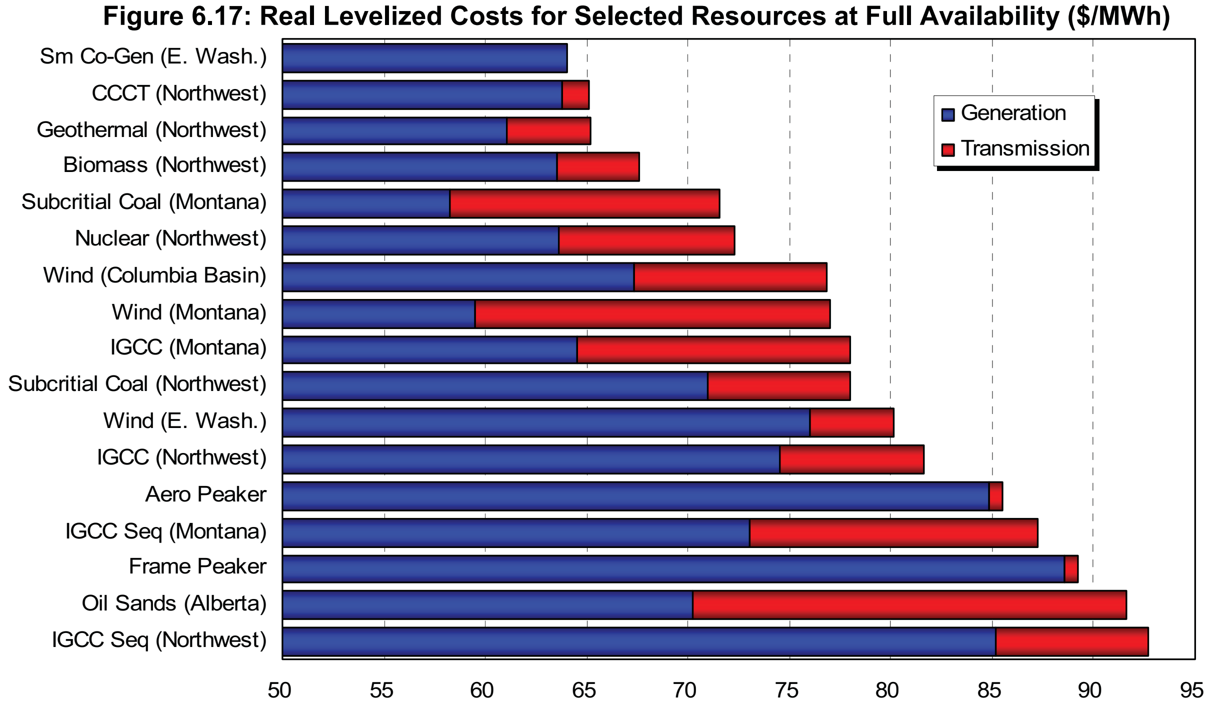
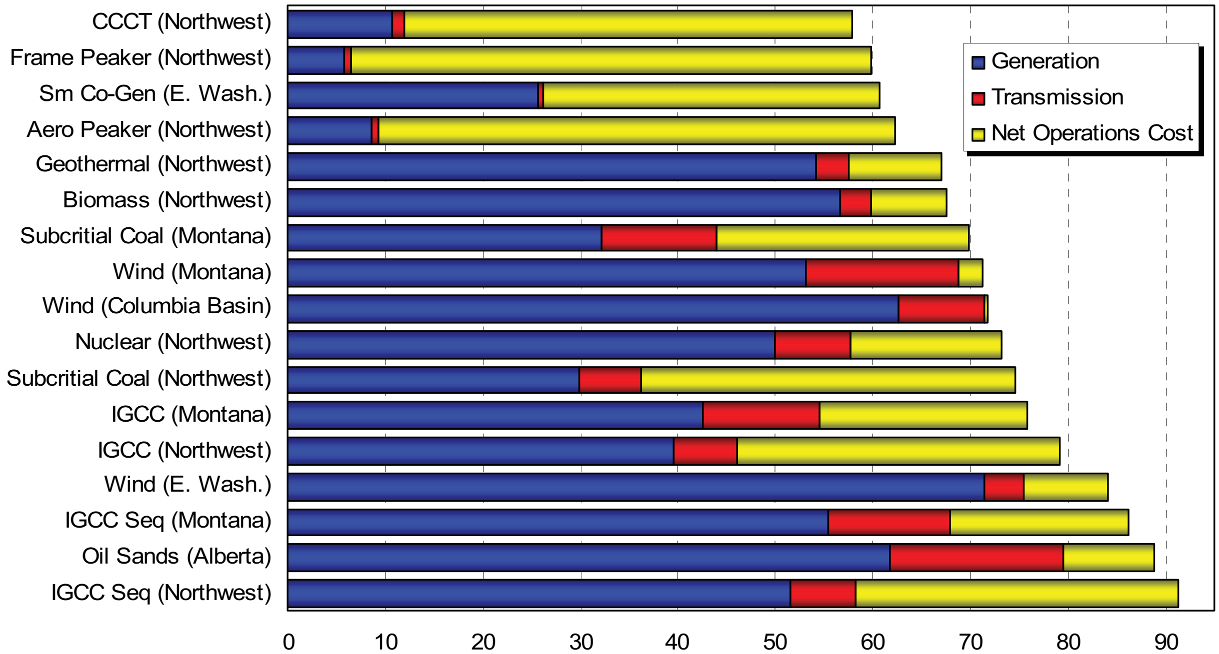


Figure 6.18: Real Levelized Costs for Selected Resources with Market Operations ($/MWh)



estimates should be available for the next IRP because several plants are being planned to start construction after 2010. Table 6.23 illustrates the levelized cost assumptions for each of the remaining plant alternatives.

SUMMARY OF RESOURCE OPTIONS

Figure 6.17 provides a comparison of the real levelized costs for each modeled resource option. Costs range from a low of $65 per MWh for a Northwest CCCT plant to more than $90 per MWh for a Northwest IGCC plant. Costs are divided between busbar generation and the transmission necessary to transport or integrate the new resource into the company's portfolio. These costs are based on the resource dispatching at full availability and at expected costs. This chart does not consider operational dispatch and other risk factors.

All-in levelized costs based on the full availability of a generating unit can be misleading. Another way to look at generation cost is to consider what the plant would cost when operated in a marketplace. In hours where the plant is uneconomic, it is not operated and market purchases replace plant output. Total fixed and variable costs, including fuel, are then combined with market displacement purchases to develop an all-in levelized cost. Figure 6.18 attempts to address these costs; it shows Generation and Transmission fixed costs per dispatch capability. The Net Operations Cost takes into account operations cost and market value. For example the cost of a CCCT in Figure 6.17 is $65 per MWh, taking into account the market value its net cost is $58 per MWh.

Resources that are not commercially viable or are prohibitively expensive over the IRP planning horizon are not modeled in this plan. Examples include: pulping chemical recovery, new hydroelectric facilities, diesel, ocean current, ocean thermal gradients, petroleum, salinity gradients, tidal energy, wave energy and distributed generation, including small scale solar and micro-turbines.

THE PRiSM MODEL

The company developed the PRiSM model to help select its Preferred Resource Strategy. The model quantifies the cost and risk of Avista's current resource portfolio and potential new resources. Each existing and future resource option has an expected operating value. Some resources provide protection against market price volatility while others do not. Combining the company's current resource portfolio with an optimal mix of new resources creates the company's Preferred Resource Strategy. Additional information is needed, including capital and fixed operating costs, to determine an optimal mix. Resource acquisition target amounts must also be considered along with the net value of the resource option.

The PRiSM model uses a linear programming routine. Linear programs help support complex decision making that have single or multiple objectives. Developing these tools requires advanced portfolio and market analysis and can be expensive and complicated. Linear programming has been used by many industries for decades, although the utility industry has been slow to adopt it for resource planning.

OVERVIEW OF THE PRiSM MODEL

PRiSM has four basic inputs: resource shortages for peak load and energy, existing resource portfolio costs and volatility, new resource options over the 300 Monte Carlo iterations market values and capital costs for potential new resources. With these inputs, the model solves for the optimal mix by year to meet capacity and energy needs given a specified level of cost and risk tolerance. The model gives a larger weighting to the first 10 years of the 20-year study. A simplified view of the linear programming objective function formula is shown in Equation 6.1.

Equation 6.1: PRiSM Objective Function

Minimize:

$$\left(X_1 * NPV_{2008-2017} + X_2 * DEV_{2017} * F\right) + \left(X_1 * \left(10\% * NPV_{2018-2027}\right) + X_2 * \left(10\% * DEV_{2027}\right) * F\right)$$

Where:

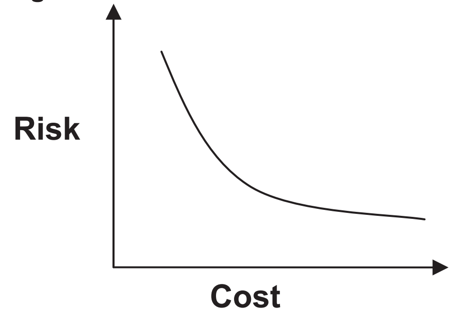
X_1 = Weight of cost reduction (between 0 and 1)
X_2 = Weight of risk reduction (1 - X_1)
F = Factor to adjust risk to equal cost in 50/50 case
DEV is the absolute deviation of power supply costs
NPV is the net present value of total cost

Subject to:

Capacity Need +/- deviation
Energy Need +/- deviation
Wash St. Renewable Portfolio Standard
Resource Limitations and Timing
Capital Spending

The PRiSM model creates a hypothetical resource selection given that a utility could add resources in exact increments as needs specify. It relies on a preferred cost and risk level for the company. The decision on what level of cost and risk reduction (X1 and X2) can be studied further using the efficient frontier approach. An efficient frontier captures the optimal amount of cost and risk reduction given the constraints of each level of weighting for cost and risk Figure 6.19 provides an example of the efficient frontier. The best point to be on the efficient frontier curve depends on the level of risk the company and its customers are willing to accept.

Figure 6.19: Efficient Frontier Line



CONSTRAINTS

As discussed above, various model constraints are necessary to solve for the optimal resource strategy. Some of the constraints are physical while others are societal. The major constraints modeled are capacity needs, energy needs, the Washington state renewable portfolio standard and resource limitations and timing.

Approximately 65 percent of the company's retail electricity load is in Washington. New state law requires that utilities with more than 25,000 customers meet 3 percent of their load by 2012, 9 percent by 2016 and 15 percent by 2020 with new renewable resources. The model selects qualified resources even if they are more expensive than other alternatives, provided that the additional cost does not exceed 4 percent of overall utility revenue requirement. Where costs are more expensive, the model can instead purchase qualified green tags; however, in the absence of a liquid forward market in green tags, their value is assumed to equal the 4 percent cap.

The model has the ability to limit annual capital expenditures for power plant and associated transmission construction. Given the resources selected in this study, we implemented a capital spending constraint. A number of resource constraints were necessary to ensure the PRiSM model selected a reasonable portfolio. The following list of resource constraints were placed on PRiSM:

- Wind acquisition is limited to 100 MW of nameplate capacity each year.
- Only carbon-sequestered coal plants are allowed.
- Acquisition of other renewables is limited to 35 MW over the first 10 years and 45 MW over the last 10 years.
- The model can sell in the short-term electricity marketplace up to 25 MW in all years except 2017 and 2018, where expiration of the PGE Capacity Sale creates a 150 MW capacity surplus that must be managed through a larger sale in that year.

The PRiSM model helps make portfolio decisions by quantifying the costs and risks associated with each resource option. It does not replace the judgment of management. Instead, this method more accurately quantifies the impact of various resource decisions and, once developed, can evaluate alternatives more efficiently than simplified portfolio analysis.

CHAPTER SUMMARY

The 2007 Integrated Resource Plan is a comprehensive modeling effort that studies the company's generation needs and needs of the entire Western Interconnect. This modeling approach allows us to identify the impacts of major fundamental changes to the electric industry, such as fuel price volatility and carbon regulations. The IRP has three main components: electric market price forecasting, risk valuation, and a combination of these two components into the PRiSM model to select the Preferred Resource Strategy.

7. MARKET MODELING RESULTS

OVERVIEW

An optimal resource portfolio must account for optionality inherent in the resource choices. For the 2007 IRP, a simulation was conducted comparing each resource's expected hourly output at a forecasted Mid-Columbia hourly price. This exercise was repeated for 300 iterations of Monte Carlo analysis. Resources that generate during on-peak hours generally contribute a higher margin to a portfolio than resources that do not. This enables certain higher average cost resources to be more cost effective than other options which generate electricity during off-peak hours.

Mid-Columbia prices are forecasted using AURORAxmp, an electric market fundamentals model developed by EPIS, Incorporated. Chapter 6 discusses the modeling assumptions used to develop the electric price forecast. In general, the hourly electricity price is set by either the operating cost of the marginal unit in the Northwest or the economic cost to move power into or out of the Northwest.

To create an electricity market price projection, a forecast of available future resources must be determined. This study uses regional (instead of the summation of individual utility needs) planning margins to set minimum capacity requirements. Western regions can be long on resources, while individual utilities may need additional resources. This imbalance can be due to ownership of certain generating resources by independent power producers and possible differences in planning methodologies for those utilities.

AURORAxmp does not select Avista's Preferred Resource Strategy (PRS); rather, it assigns values to resource alternatives used in the PRS exercise. Using several market price forecasts can determine the value and volatility of a resource portfolio. Since we do not know what will happen in the future with a significant degree of certainty, it relies on scenario planning to help determine the best resource strategy. Scenario planning is done by developing many different market price forecasts using different assumptions than the Base Case or by changing the underlying statistics of a study. These alternate cases are split into two different categories: futures and scenarios.

A future is a stochastic study using Monte Carlo analysis to quantify risks. These studies include 300 iterations of varying gas prices, loads, hydro, thermal outages, wind shapes and emissions prices. A scenario is a deterministic study made by changing one or more specific underlying model assumptions. These cases are generally used to understand specific changes, but they do not quantitatively assess all risks facing the company.

STUDIED FUTURES

The company studies four primary futures for the 2007 IRP, including: Base Case, Volatile Gas, Unconstrained Carbon and the Climate Stewardship Act of 2005 (High Carbon Charges). Each future provides information to help the company identify its Preferred Resource Strategy and to help explain the impact of changing conditions on its Preferred Resource Strategy.

CHAPTER HIGHLIGHTS

- Gas-fired resources continue to serve the majority of new loads in the West through the IRP timeframe.
- Market prices are forecast to fall from today's level through 2011, and then steadily rise after 2015; 2008-2027; levelized Mid-Columbia prices are forecasted to be $51.25 (real 2007 dollars).
- Electricity and natural gas prices are expected to remain tightly correlated.
- National Commission on Energy Policy's carbon reduction strategy is included in the Base Case.
- This IRP models four stochastic futures.
- Avoided costs consider capacity and risk reduction when the company is resource deficit.

Table 7.1: Base Case Key Assumptions

	Entire Study	2008	2017	2027
Natural Gas Price @ Sumas ($/Dth)	5.42 (Real)	6.54 (Nominal)	6.44 (Nominal)	11.18 (Nominal)
Natural Gas Price @ Henry Hub ($/Dth)	6.31 (Real)	7.62 (Nominal)	7.50 (Nominal)	13.02 (Nominal)
Northwest Load (aMW), (WA, OR, N. Idaho)	1.72% (AAGR)	17,584	20,708	24,715
Western Interconnect Load (aMW)	1.95% (AAGR)	100,056	120,056	147,348
Northwest Non-Coincident Peak Demand (MW), (WA, OR, N. Idaho)	1.38% (AAGR)	25,749	29,311	33,863
Western Interconnect Non-Coincident Peak Demand (MW)	2.37% (AAGR)	162,672	202,388	259,667
Hydro Energy (aMW)	14,152	14,067	14,162	14,162
CO_2 Tax ($/Ton)	4.35 (Real)	0.00	9.54 (Nominal)	14.45 (Nominal)

BASE CASE FUTURE

The Base Case future study represents Avista's best estimate of future costs and prices. It uses average conditions and expected values for its assumptions. Many of the key assumptions for this case are described in Chapter 6; a summary of them is shown in Table 7.1. Future load growth is served primarily by natural gas-fired, combined-cycle plants, although many simple-cycle plants are built to meet planning margin targets. Renewable resources are included to meet various states' renewable portfolio standards (RPS), as well as to provide resource diversification. The Base Case assumes that states with RPS requirements will not construct renewable resources in exceedance of such requirements because of the relative scarcity of these resources. The federal production tax credit, a large subsidy that offsets a significant portion of the higher development and operation costs of renewable resource, is assumed to be extended until 2014.

The Base Case assumes that coal resources can be built only in Rocky Mountain states to serve local electrical loads; the energy cannot be exported due to various state import laws preventing it. Constraining coal plant construction leaves natural gas-fired resources to meet most of the future load growth in the West. Table 7.2 provides cumulative new generation resources assumed in the Base Case.

As a region, the Northwest is forecast to be in a surplus position through 2020. New resource construction before 2020 occurs to meet RPS and sub-regional requirements. Figure 7.1 illustrates the Northwest resource position during the system's one-hour peak

Table 7.2: Cumulative Western Interconnect Resource Additions (Nameplate MW)

	2010	2015	2020	2027
CCCT	5,280	15,360	23,040	46,080
SCCT	17,002	31,793	46,661	52,761
Pulverized coal	0	2,800	3,600	5,200
IGCC coal	0	0	2,550	11,900
IGCC coal w/ sequestration	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	**24,936**	**61,629**	**100,228**	**151,484**

Figure 7.1: Oregon, Washington and Northern Idaho Resource Positions (GW)

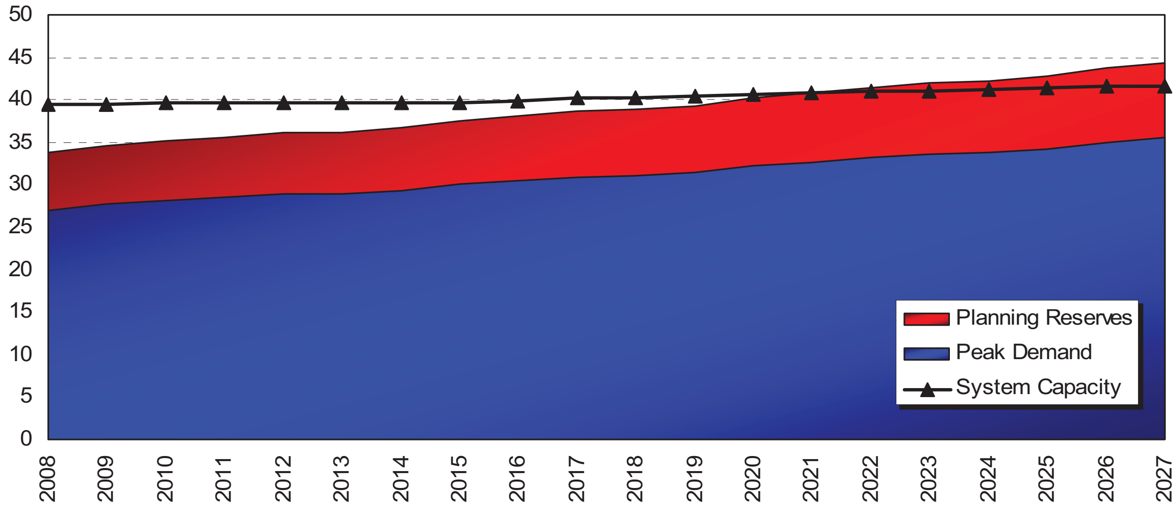
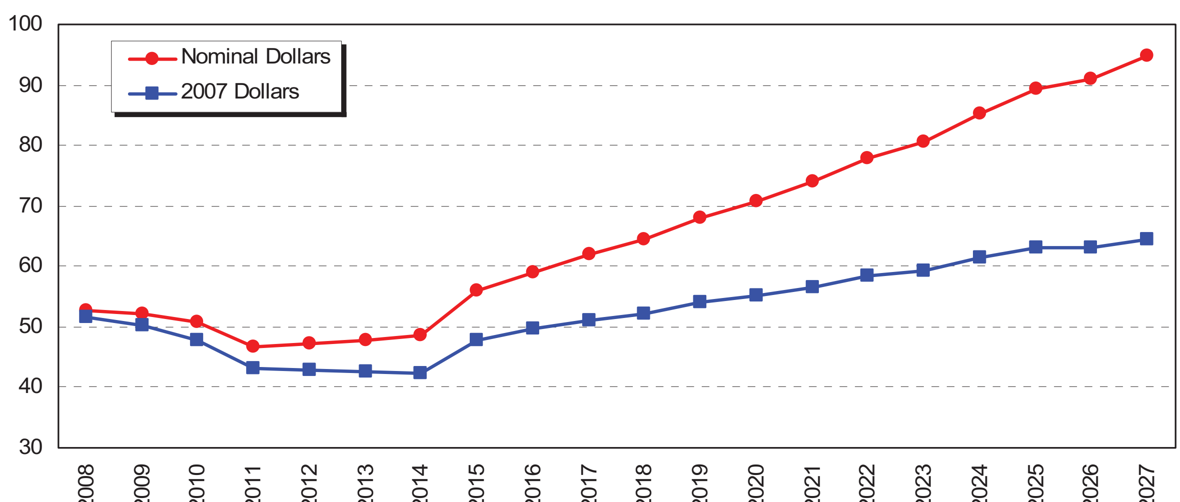


Table 7.3: Oregon, Washington and Northern Idaho Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	0	0	0	1,920
SCCT	0	0	0	540
Pulverized coal	0	0	0	0
IGCC coal	0	0	0	0
IGCC coal w/ sequestration	0	0	0	0
Wind (nameplate)	0	44	2,832	5,835
Other Renewables	150	261	1,017	1,871
Total Nameplate Capacity	**150**	**305**	**3,849**	**10,166**

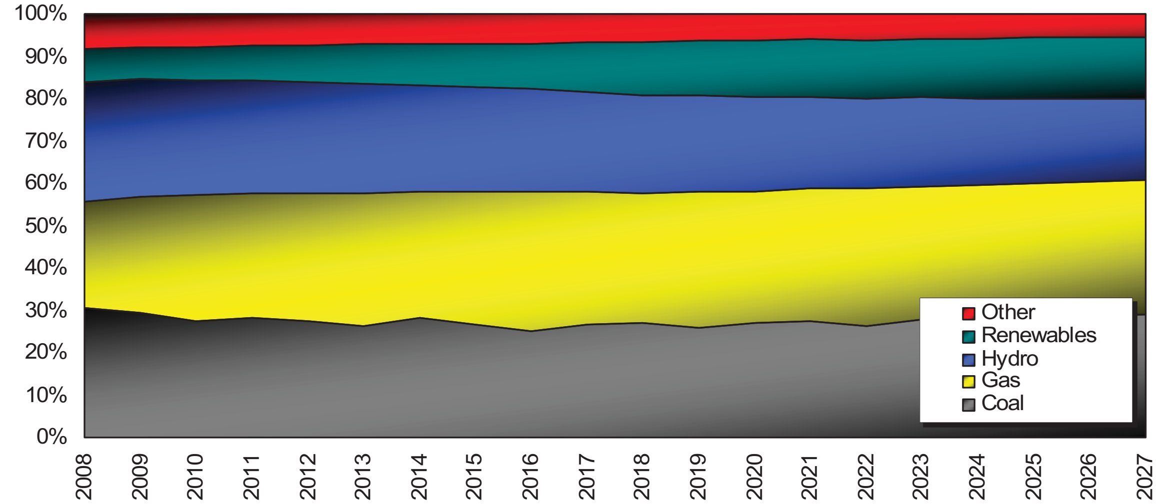
Figure 7.2: Mid-Columbia Electric Price Forecast ($/MWh)



load condition. Regional resource deficiencies begin in 2021, and the model begins non-RPS driven resource construction at this time. Table 7.3 shows new Northwest resources included in the Base Case.

Individual utilities with short positions are building additional resources even though the Northwest is in surplus. Some level of new resource construction is likely; however, utilities will probably cover at least a

Figure 7.3: Western Interconnect Resource Dispatch Contribution



portion of their needs by purchasing existing resources that presently are surplus to the region's needs. Regional resources not currently owned by local utilities will probably be less expensive and entail less acquisition risk than green field options.

Between 2008 and 2027, projected annual average power prices for the Mid-Columbia market are $51.25 in 2007 real dollars. Taking inflation into account, the cost of power is forecast at $60.26 in 2007 nominal dollars. Figure 7.2 illustrates the nominal and real price of Mid-Columbia power on an annual average basis. Prices are forecast to decline in real terms until 2015, and then rise with the imposition of carbon taxes and higher natural gas prices.

Natural gas plants are the primary source of new generation in the Western Interconnect forecast. Coal serves a large portion of load, though few new plants are built. Figure 7.3 illustrates how each resource category contributes to serving loads over the IRP timeframe.

Figure 7.2 shows expected annual prices, but each year likely will not experience average conditions or witness each of our modeling assumptions. The company conducts a stochastic study to quantify the risk of varying

Figure 7.4: Base Case Stochastic Mid-Columbia Prices ($/MWh)

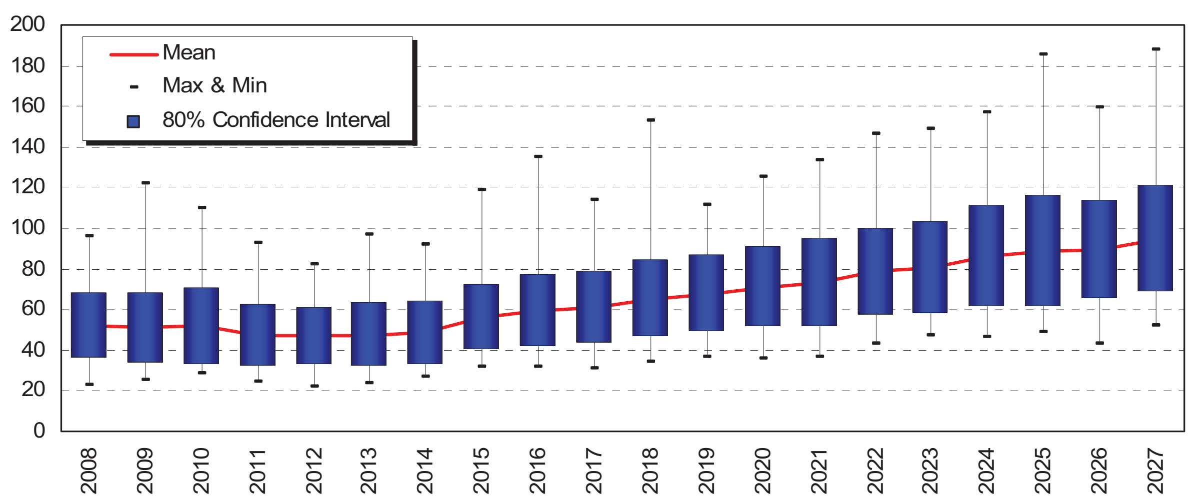
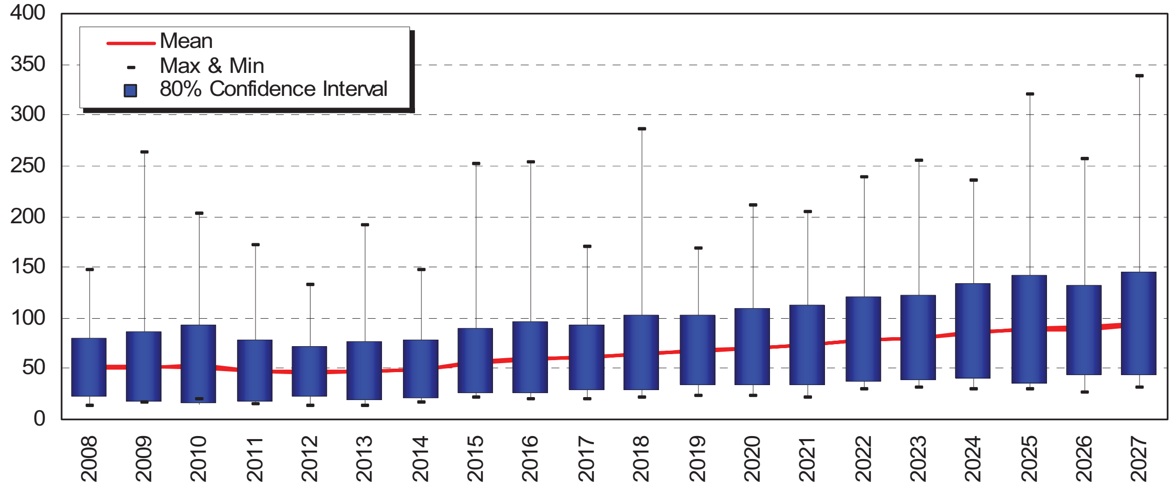


Figure 7.5: Volatile Gas Future Stochastic Mid-Columbia Electric Forecast ($/MWh)



future prices. Figure 7.4 shows average annual prices for the deterministic and stochastic studies. In past studies, including the 2005 IRP, stochastic results were slightly higher than deterministic results. In the current study, higher planning margins keep the stochastic mean at the same level as the deterministic values. There is an 80 percent probability that the 2008 annual average price at Mid-Columbia will be between $35 and $75. The figure also shows minimum and maximum annual average prices recorded across the stochastic Base Case study.

VOLATILE GAS FUTURE

To illustrate the potential for greater price volatility in the natural gas marketplace, a stochastic study assuming a more volatile gas distribution was developed. The standard deviation of expected natural gas prices was doubled to create more volatility. Figure 7.5 shows the results of the study. The 80 percent confidence level of 2008 prices increased by slightly more than 50 percent, to between $21 and $82 per MWh.

UNCONSTRAINED CARBON FUTURE

The Unconstrained Carbon future is identical to the Base Case, except that no carbon emission costs are included in the market forecast. Table 7.4 presents Western Interconnect resource selections under this future. Compared to the Base Case, the Unconstrained Carbon future builds the same quantity of resources, but the mix differs. This case selects fewer SCCTs and more coal-fired power plants.

This future shows that the National Commission on Energy Policy's proposed carbon mitigation strategy, included in the company's Base Case future, will not

Table 7.4: Unconstrained Carbon Future Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	2,400	15,360	23,040	48,000
SCCT	19,860	31,693	45,299	49,031
Pulverized coal	0	3,600	4,400	6,800
IGCC coal	0	425	6,375	11,900
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	**24,914**	**62,754**	**103,491**	**151,274**

Figure 7.6: Unconstrained Carbon Future Mid-Columbia Electric Price Forecast ($/MWh)

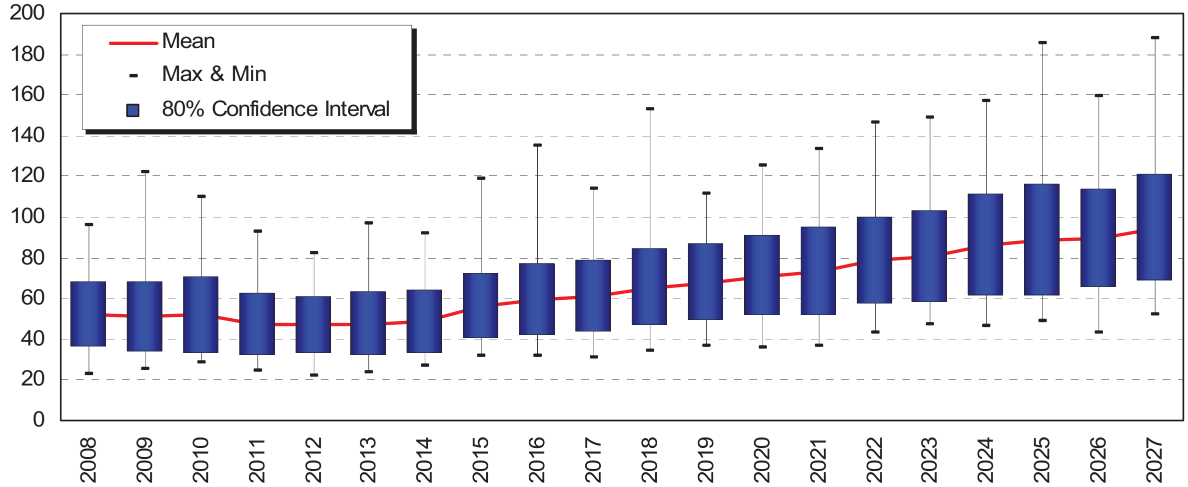


Table 7.5: CSA Carbon Charge Future, Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	6,240	12,000	23,520	46,560
SCCT	15,176	33,206	44,010	50,573
Pulverized coal	0	1,200	1,200	1,600
IGCC coal	0	0	0	2,975
IGCC coal w/ sequestration	0	0	1,203	5,213
Nuclear	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	**24,070**	**58,082**	**94,310**	**142,464**

significantly affect the future resource mix, but it will increase electricity prices by approximately 7 percent, or $3.69 per MWh levelized real 2007 dollars, as shown in Figure 7.6.

THE CLIMATE STEWARDSHIP ACT OF 2005 (HIGH CARBON CHARGES) FUTURE

The Climate Stewardship Act of 2005 (CSA), otherwise known as the McCain-Lieberman Bill, was first introduced in the U.S. Senate in October 2003. This comprehensive plan was designed to reduce greenhouse gas emissions to year 2000 levels by 2010. The bill would reduce emissions through a market-based tradable allowance system patterned after the sulfur dioxide emissions permit market established by the Clean Air Act of 1990.

The company used the results of an EIA study of this bill for its High Carbon Charges future, as it is the most comprehensive analysis available. The CSA was used in this study as a proxy for all of the pending federal legislation. More up-to-date studies, or possibly federal laws and subsequent economic analyses, will be available and used in the Base Case for the 2009 IRP. Large carbon charges on electricity generating facilities will likely stop or severely restrict construction of new non-sequestered coal plants. In this future, utilities will probably rely most heavily on gas-fired resources, as shown in Table 7.5.

In this future, existing coal plants dispatch many fewer hours than in the Base Case, because carbon credits are more valuable than electricity generated by these plants.

Figure 7.7: CSA Carbon Charge Future: WI Resource Dispatch Contribution

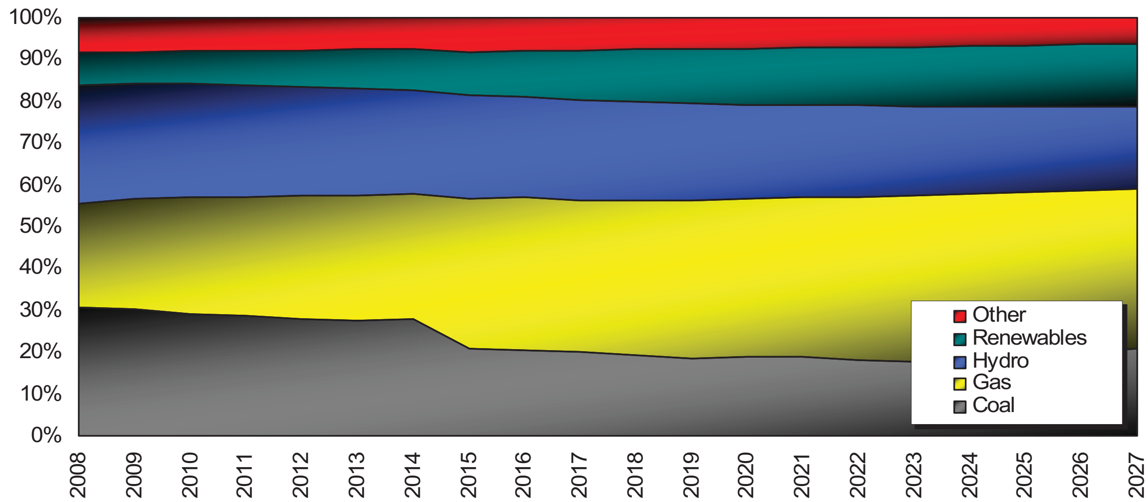


Figure 7.8: CSA Carbon Future, Mid-Columbia Electric Price Forecast ($/MWh)

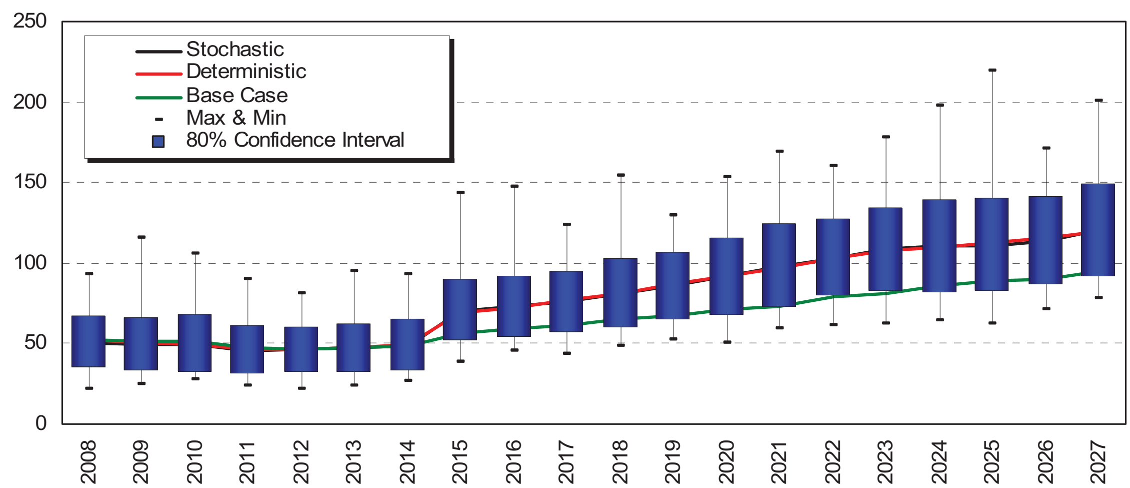


Figure 7.9: Western Interconnect Total Carbon with Different Futures (Million Tons of CO_2)

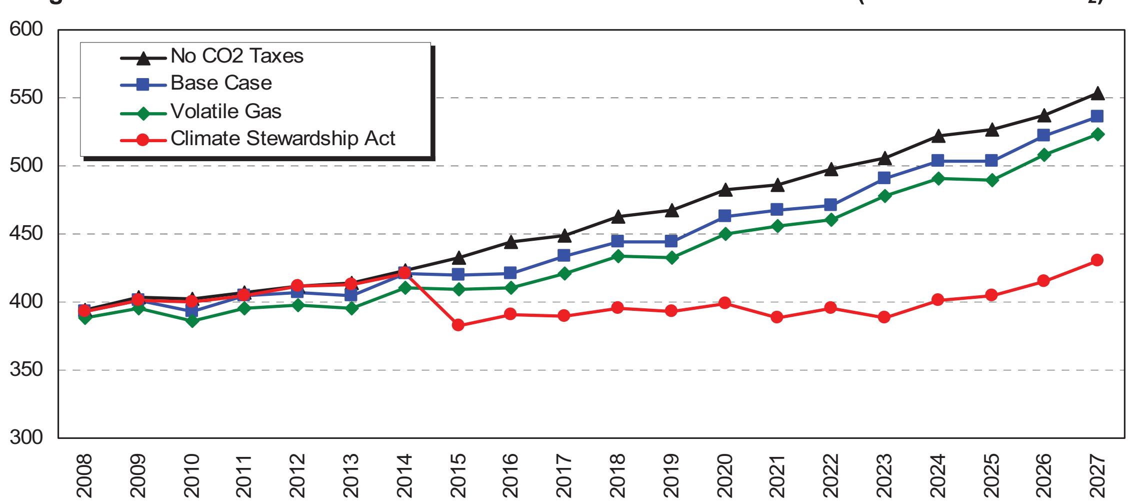


Table 7.6: Comparative Levelized Mid-Columbia Prices and Risk (Real 2007 Dollars)

Future	Mean	Standard Deviation	Coefficient of Variation	80% Confidence Range	
				Low	High
Base Case	$51.02	$12.23	24%	$35.35	$66.70
Volatile Gas	$51.02	$23.43	46%	$20.99	$81.05
Unconstrained Carbon	$47.38	$11.74	25%	$32.34	$62.42
Climate Stewardship Act	$58.63	$12.96	22%	$42.03	$75.25

Table 7.7: Comparative Levelized Mid-Columbia Prices and Risk (Nominal 2007 Dollars)

Future	Mean	Standard Deviation	Coefficient of Variation	80% Confidence Range	
				Low	High
Base Case	$60.13	$14.42	24%	$41.65	$78.61
Volatile Gas	$60.12	$27.62	46%	$24.72	$95.51
Unconstrained Carbon	$55.84	$13.83	25%	$38.11	$73.57
Climate Stewardship Act	$69.07	$15.28	22%	$49.50	$88.65

Figure 7.7 highlights a significant reduction in coal dispatch beginning in 2015 when carbon charges start.

Figure 7.8 illustrates the impact higher carbon charges would have on the Mid-Columbia price forecast. The chart shows that prices increase significantly in 2015 when the carbon charges begin.

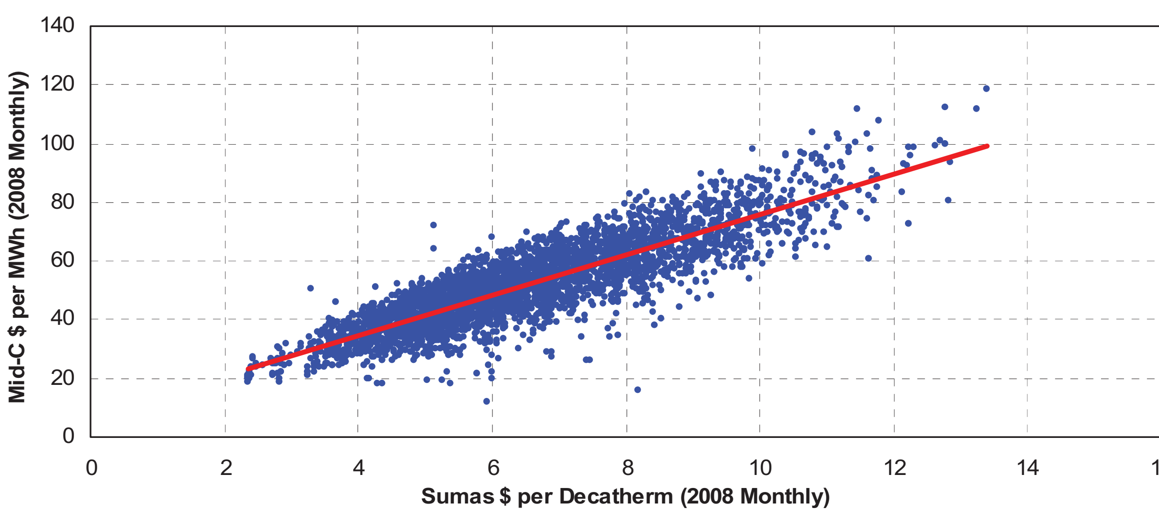
Higher carbon emission prices significantly decrease carbon emissions in the Western Interconnect when compared to the other futures. This reduction is illustrated in Figure 7.9.

FUTURES SUMMARY AND COMPARISON

The results of the futures analyses show that average electricity prices vary from the Base Case by as much as 15 percent. Tables 7.6 and 7.7 show levelized prices for each future in real and nominal 2007 dollars. Natural gas prices are a key volatility driver; though carbon charges push prices up, they do not significantly affect price volatility.

The company conducted a regression and correlation analysis to study natural gas price impacts on the electricity marketplace. The study was conducted for

Figure 7.10: Sumas Gas Price Versus Mid-Columbia Electric Prices



Equation 7.1: 2008 Natural Gas Price to Electric Price Regression Equation

$$PRICE_{2008} = 6.8436 * G + 7.2168$$

Where:

G is the estimated annual average 2008 Sumas natural gas price

Equation 7.2: 2016 Electric Price Regression Equation

$$PRICE_{2016} = 31.22 + 6.86 * G + 0.56 * C - 25.74 * H + 361.84 * D$$

Where:

G is the nominal Sumas natural gas price in 2016
C is the nominal carbon tax amount in 2016
H is an index of hydro conditions compared to average conditions
D is the annual average demand (load growth) for energy in the Northwest

calendar year 2008 and uses monthly Mid-Columbia electric and monthly Sumas natural gas prices for all 300 iterations of the Base Case. Figure 7.10 shows the high level of correlation, 86 percent, with 75 percent of the variation in electricity prices explained by variation in natural gas prices. See Equation 7.1 for the regression equation.

The regression equation shows that electricity prices will rise by $6.85 for each dollar change in natural gas prices. By including other independent variables, the regression equation is able to predict 99 percent of overall price volatility. Equation 7.2 identifies each additional variable's coefficient used to forecast the average annual electricity prices in 2016.

Table 7.8 provides annual average electric price estimates using the Base Case regression equation for each of the studied futures. The equation performs well at predicting electricity prices across the cases, even though the CSA future uses a different stochastic methodology to model carbon charges. Further work in this area could simplify future IRP analyses by limiting the number of stochastic futures run through AURORAxmp.

SCENARIOS

The 2007 IRP evaluates fewer scenarios than the 2005 IRP. Many of the market structure impacts from assumption changes were discovered by analysis of those cases and in the draft 2007 IRP. The following scenarios were studied for this plan:

- Constant natural gas prices,
- 20 percent decrease in gas price escalation,
- 20 percent increase in gas price escalation,
- Western Interconnect loads increasing 50 percent faster,
- Western Interconnect loads decreasing 50 percent slower,
- Nuclear plant availability beginning in 2015 and
- Electric car.

Table 7.8: Multiple Regression Coefficient Results

Variable (Nominal $)	Base Inputs	CSA Future	No CO_2 Tax
Sumas Natural Gas Price	$6.25	$6.25	$6.25
CO_2 Price	$8.88	$34.05	$0.00
Hydro Percent of Avg	100%	100%	100%
Annual Avg Load Growth	1.70%	1.70%	1.70%
Predicted Price	**$59.50**	**$73.56**	**$54.53**
AURORAxmp Price	**$59.44**	**$75.93**	**$52.26**
% Error	***0.1%***	***-3.1%***	***4.3%***

Figure 7.11: Natural Gas Forecasts, Constant Gas Growth Versus the Base Case ($/Dth)

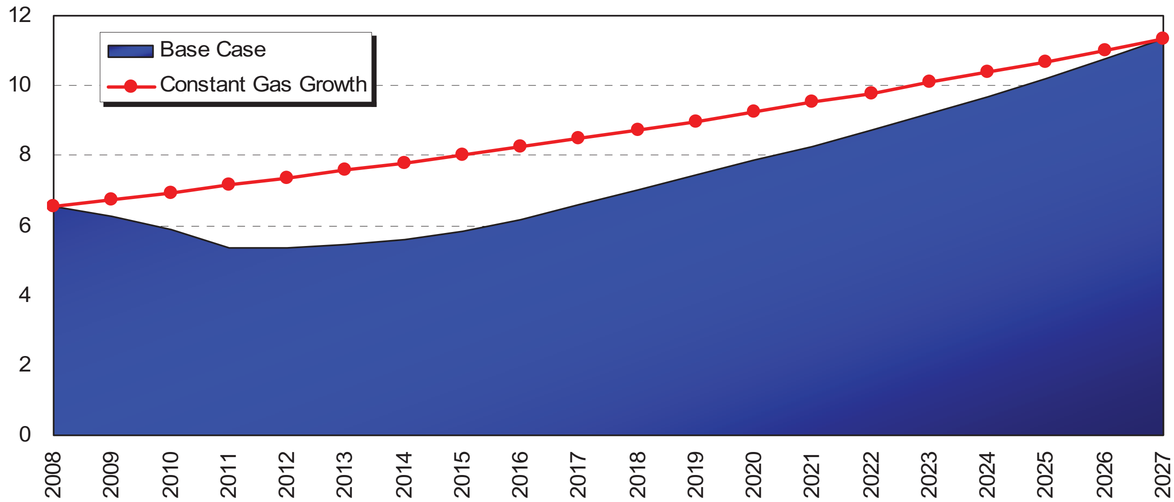


Table 7.9: Constant Gas Growth Scenario, Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	2,400	4,320	17,760	46,080
SCCT	18,339	34,645	44,680	52,556
Pulverized coal	0	4,000	4,000	4,400
IGCC coal	0	6,375	8,925	12,750
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	**23,393**	**61,016**	**99,742**	**151,329**

Figure 7.12: Natural Gas Price Forecast Scenarios Versus the Base Case ($/Dth)

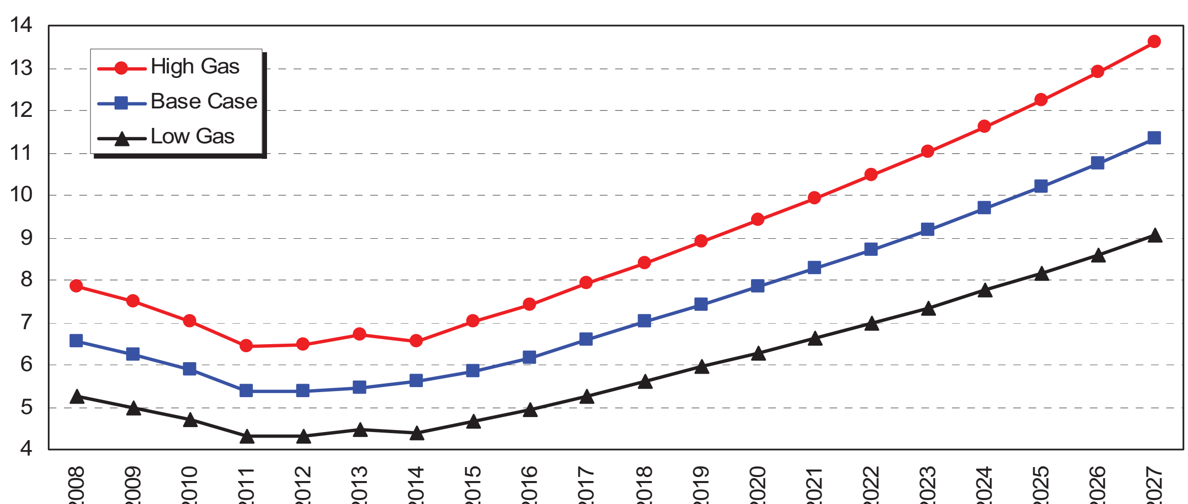


Table 7.10: High Natural Gas Price Scenario: Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	5,280	14,400	20,640	39,840
SCCT	15,924	33,083	44,788	52,096
Pulverized coal	0	2,800	3,200	8,800
IGCC coal	0	2,550	7,225	16,575
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	**23,858**	**64,509**	**100,230**	**152,854**

For comparative purposes, all market scenario Mid-Columbia prices are shown in the summary on in Table 7.19 later in this chapter. A detailed price forecast for each scenario, including scenarios studied for the draft IRP, can be found at the company's IRP website.

CONSTANT NATURAL GAS PRICES SCENARIO

This scenario illustrates the effect on electric prices and the Preferred Resource Strategy if gas prices do not fall for several years but continue to increase from the current price level. As discussed in Chapter 5, gas prices are forecast to fall from 2008 to 2012. Since the gas forecast relies on many assumptions, this alternative was studied to quantify the risk of gas prices continuing to rise throughout the forecast horizon. Figure 7.11 illustrates the scenario's gas price assumption and compares it to the Base Case forecast. Levelized gas prices rise from $6.85 in the Base Case to $8.19 in this scenario (nominal 2007 dollars).

Table 7.9 presents incremental resources selected to meet future loads in this scenario. Fewer combined-cycle plants are built early in the study compared to the Base Case. Gas-fired resources are replaced by coal-fired generation. The Mid-Columbia electricity price forecast from this scenario can be found in Table 7.17.

INCREASING AND DECREASING NATURAL GAS PRICE FORECAST SCENARIOS

High and low natural gas price forecasts would significantly affect resource planning. Figure 7.12 illustrates the natural gas prices used in these scenarios; prices are assumed to be 20 percent higher or lower than the Base Case forecast.

Table 7.11: Low Natural Gas Price Scenario: Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	3,360	14,880	24,000	53,280
SCCT	19,087	34,162	47,307	54,564
Pulverized coal	0	400	3,200	4,000
IGCC coal	0	0	0	4,250
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	**25,101**	**61,118**	**98,884**	**151,637**

Table 7.12: Western Interconnect Average Demand (aGW)

Scenario	2008	2015	2020	2025
Base Case	102	116	129	143
High Load	103	126	147	172
Low Load	101	108	113	119

Table 7.13: High Load Escalation Scenario: Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	9,120	22,080	45,600	112,320
SCCT	24,080	48,670	61,507	66,320
Pulverized coal	0	2,000	3,600	8,800
IGCC coal	0	0	7,650	16,150
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	35,854	84,426	142,734	239,133

Table 7.14: High Load Escalation Scenario: Change Cumulative Resources (%)

	2010	2015	2020	2027
CCCT	73	44	98	144
SCCT	42	53	32	26
Pulverized coal	0	-29	0	69
IGCC coal	0	0	200	36
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	0	0	0	0
Other Renewables	0	0	0	0
Total Nameplate Capacity	44	37	42	58

Table 7.15: Low Load Escalation Scenario: Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	2,400	2,400	2,400	8,160
SCCT	12,140	21,680	28,443	35,052
Pulverized coal	0	2,000	2,800	3,600
IGCC coal	0	0	425	3,825
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	17,194	37,756	58,445	86,180

Table 7.16: Low Load Escalation Scenario: Change Cumulative Resources (%)

	2010	2015	2020	2027
CCCT	-55	-84	-90	-82
SCCT	-29	-32	-39	-34
Pulverized coal	0	-29	-22	-31
IGCC coal	0	0	-83	-68
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	0	0	0	0
Other Renewables	0	0	0	0
Total Nameplate Capacity	-31	-39	-42	-43

Tables 7.10 and 7.11 present the resources selected for each of the gas price scenarios. As gas prices increase, new coal generation increases and fewer resources are built. When gas prices decrease, fewer coal-fired and more SCCT plants are built relative to the Base Case.

INCREASING AND DECREASING REGIONAL LOAD SCENARIOS

Increases and decreases to Western Interconnect load growth will affect future market conditions. These scenarios were developed to provide a better understanding of how the market and resource mixes would change if higher or lower overall load growth patterns developed across the Western Interconnect. Table 7.12 compares these scenarios to the Base Case. Resources selected are similar to the Base Case, but more or fewer resources are added in the high and low cases, respectively.

Tables 7.13 through 7.16 show the absolute and percentage changes in the asset mix from the Base Case. Market prices are also similar to the Base Case, as seen in Table 7.19. These scenarios did not assume any adjustments to the RPS levels because the company does not believe this will significantly impact market prices or the value of resource options available.

NUCLEAR PLANTS SCENARIO

The Northwest has not considered nuclear plants as a viable new resource option for over 20 years. This scenario illustrates the market impact if new nuclear resources were available. Nuclear plants would not materially impact Mid-Columbia prices, assuming nuclear plant capital costs of $3,100 per kW.[1] Few new nuclear plants would be constructed at this high capital cost. The NPCC's Fifth Power Plan estimated nuclear capital cost to be $1,735 per kW.[2] Nuclear plants could significantly impact Mid-Columbia markets at this lower level. When one or more of the plants proposed in the Eastern U.S. are constructed, we should have access to better cost information. Table 7.17 presents the resources selected for the Nuclear Plant scenario. A single 1,100 MW nuclear plant was selected between 2015 and 2020; 13 nuclear plants were selected between 2020 and 2027 in this scenario.

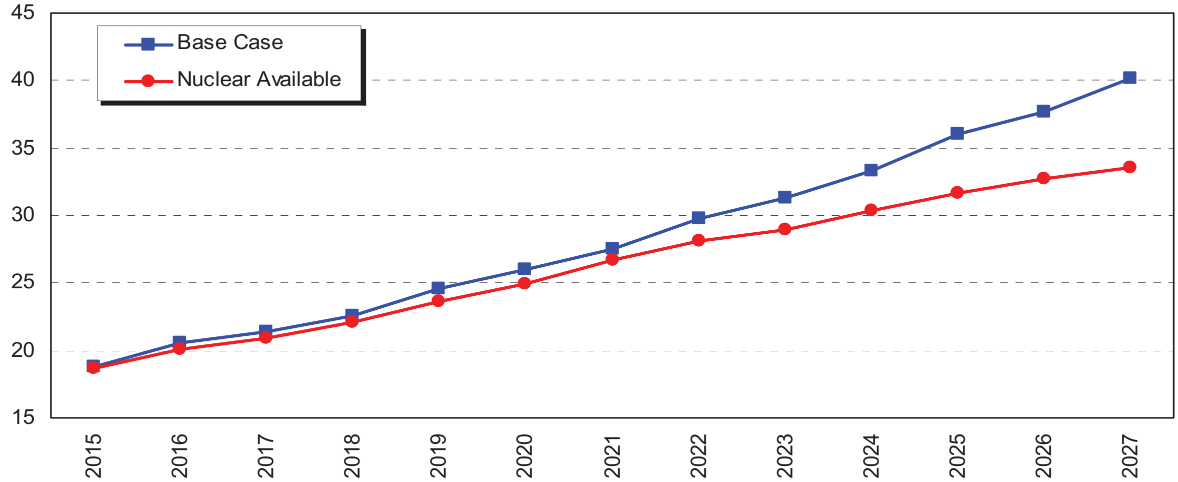
Nuclear plants would provide substantial fuel savings relative to the Base Case. Even though few nuclear plants are constructed because of high capital costs, fuel savings equal $10 billion net present value over 20 years. If more nuclear plants were constructed, the fuel savings would increase linearly. Figure 7.13 shows the fuel saving from the Base Case between 2015 and 2027.

Table 7.17: Nuclear Plants Scenario: Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	5,280	14,400	19,680	32,640
SCCT	16,438	27,832	43,395	51,885
Pulverized coal	0	2,400	2,800	4,000
IGCC coal	0	0	4,675	10,625
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	1,100	15,400
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	24,372	56,308	96,027	150,093

[1] This represents overnight costs.
[2] The NPCC 5th Power Plan estimates a nuclear plant to cost $1,450 per kW in 2000 Dollars.

Figure 7.13: Western Interconnect Fuel Costs, Nuclear Beginning in 2015 (Nominal $Billions)



Lower fuel costs are not the only societal benefit of nuclear power; a commensurate reduction in greenhouse gases and other emissions would occur if nuclear power were added to the preferred resource mix. Figure 7.14 demonstrates that carbon emissions stabilize across the Western Interconnect as more nuclear plants come on-line in the nuclear scenario. While there are clear financial and societal benefits from nuclear power, the benefits are currently outweighed by capital cost uncertainties, waste management issues and other public policy considerations.

ELECTRIC CAR SCENARIO

Rising energy costs combined with concerns over the energy security of the United States have stimulated efforts to find alternatives to fueling transportation

The Tesla All-Electric Roadster Photo Credit: Tesla Motors

Figure 7.14: Western Interconnect Carbon Emissions (Million Tons of CO_2)

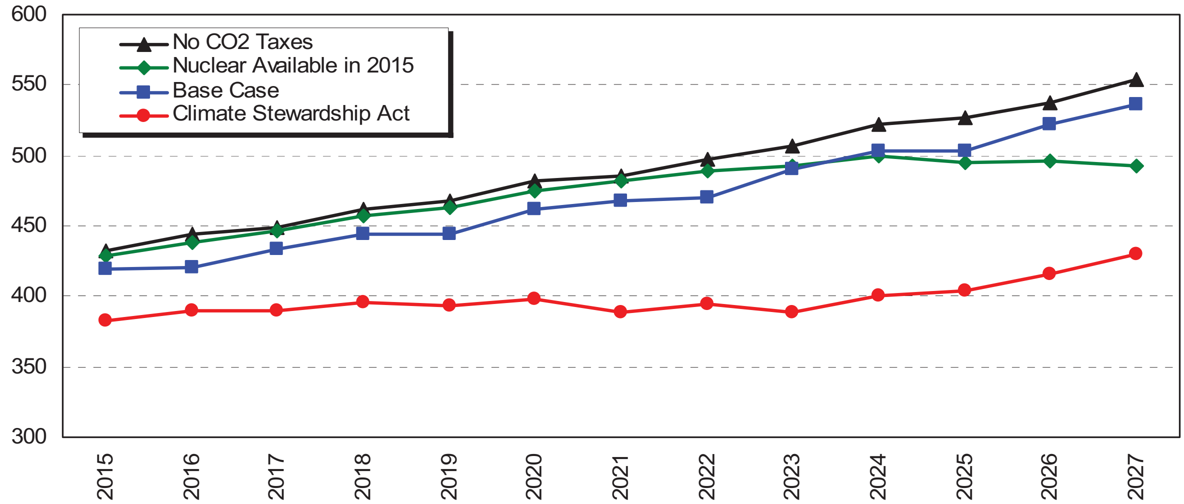
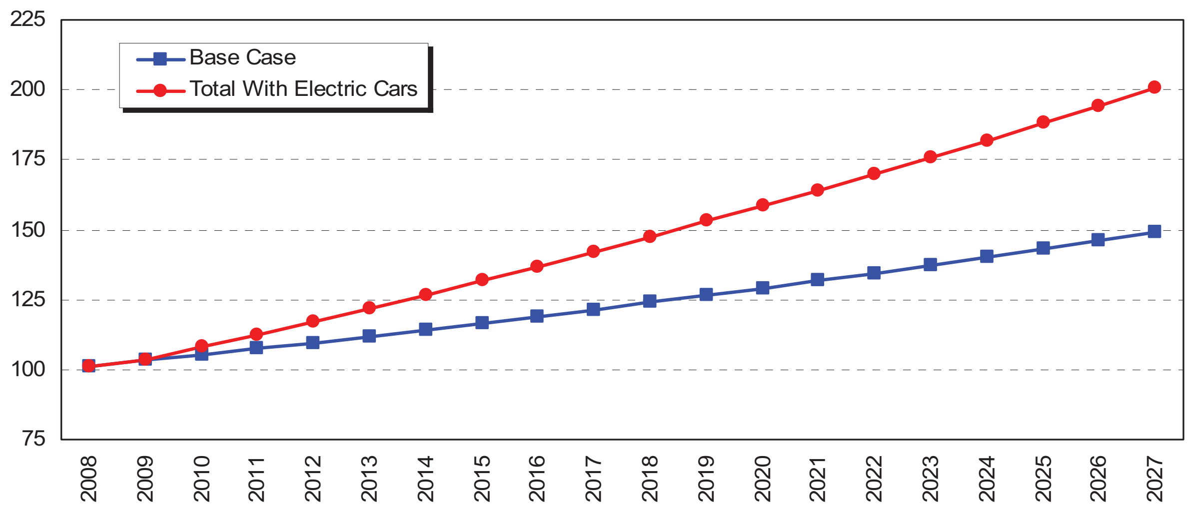


Figure 7.15: Impact of Electric Cars on the Western Interconnect (aGW)



vehicles with petroleum. There are many significant subsidies provided for hybrid cars, ethanol and bio-diesel production, and hydrogen fuel cells. Though significant, subsidies for hybrid cars arguably do not make them financially attractive to most buyers.

Properly designed, electric cars have the potential to help optimize electric system infrastructure. Some initial analyses have been completed, but to-date no study has attempted to holistically quantify the costs and benefits of converting the U.S. car and light truck fleet to all- or mostly electric fuel.[3]

Avista developed an Electric Car scenario to consider the potential benefits an electric car fleet might have on the U.S. power industry and how some or all of these benefits might be used to more rapidly transition the automobile industry toward electric-only or electric-hybrid technologies.

[3] Most other studies on electric vehicles are conducted in foreign countries and focus on social costs and benefits http://www.kfb.se/pdfer/R-00-46.pdf and http://www.cenerg.ensmp.fr/francais/themes/impact/pdf/ElecVehicle(Funk&Rabl1999).pdf. Estimates of the number of vehicles are assumed to be at the 1999-2003 annual rate of vehicle change taken from a recent Polk Company study.

Scenario Description

The Electric Cars scenario assumes that all passenger cars and light trucks across the Western Interconnect are fueled primarily with electricity by 2020.[4] The existing fleet is replaced or retrofitted entirely over this timeframe at a rate of 10 percent per year, a rate modestly lower than the natural replacement of vehicles in the United States.[5] An estimated 31.8 million electric passenger cars and 34.8 million electric passenger trucks and SUVs will be found in the Western Interconnect fleets by 2020. Each vehicle will travel an average of 12,500 miles per year and will consume a net (including charging losses) 0.22 kWh per mile, while heavier trucks and SUVs will consume 0.39 kWh per mile.[6] Figure 7.15 illustrates the incremental electric-car load.

Total estimated incremental electrical load in 2020 will equal 85.8 billion kWh (9.8 aGW) and 169.3 billion kWh (19.3 aGW) for cars and light trucks, respectively. This creates an increase in total Western Interconnect load of approximately 25 percent in 2020. Because the projected growth rate of electric vehicle purchases is higher compared to traditional electricity load growth, by the end of the study electric vehicles will consume one-third of all electricity. However, as future electric cars become more efficient, the growth trajectory of the new demand could become more gradual.

In addition to the benefits electric cars provide to non-utility interests, electric cars also provide a number of benefits from a utility perspective. The most obvious of these benefits is the ability to increase load factor, thereby raising the utilization of infrastructure and lowering per-unit delivered energy costs. Other utility benefits might be even more significant. The Western Interconnect electricity grid is currently comprised of approximately 200,000 MW of generating capacity. This study estimates that approximately 15 percent, or 30,000 MW, of this capacity stands ready to meet load requirements during extreme weather events or for back-up when larger plants experience forced outages. Except during these short intervals, this capacity sits idle. By 2027, capacity in the Western Interconnect will grow to 300,000 MW in the Base Case, with 45,000 MW held in reserve. Utilities also reserve generation capacity to follow intra-hour load and resource fluctuations. This study estimates that the Western Interconnect reserves 6 percent (12,000 MW today, 18,000 MW in 2027) of its capacity for reserve services.

"Raw" capacity—in other words, the portion of a peaking plant that cannot be recovered through energy sales over its lifetime—is assumed in this scenario to be worth $300/kW, or $45/kW-year in 2007 dollars. At this price, back-up capacity today costs the Western Interconnect approximately $1.3 billion annually. Regulation reserves at this price equal an additional $0.5 billion annually. Between 2010 and the end of the IRP study timeframe in 2027, total savings from reduced back-up and reserve capacity equals $25 billion on a present value basis.

An electric automobile fleet also would have the potential to assist the grid in managing wind integration. Recent studies confirm that wind generation consumes increasing amounts of generation flexibility. They show that wind integration costs range from $2 to $10 per MWh. This Base Case IRP future estimates that 35,000 MW of wind generation will be installed in the Western Interconnect by 2027, generating approximately 99.3

[4] Though this scenario focuses on the Western Interconnect due to modeling limitations, its results likely could be extrapolated across the U.S.
[5] 37BetterMotors states the average length of vehicle ownership in the U.S. is between 5 and 10 years. http://37signals.com/better_motors.php. Full Scrappage rate of passenger vehicles in the U.S. was 4.5 percent in 2005 according to Green Car Congress. http://www.greencarcongress.com/2006/02/us_vehicle_flee.html
[6] This baseline assumption of .22 kWh per mile comes from data released on the Tesla Roadster. A pro-rata increase based on vehicle weights was applied to SUVs and light trucks.

million MWh annually. The wind integration costs could vary between $0.2 and $1 billion. Between 2010 and 2027, the total value ranges from $1 to $5 billion.

Electric vehicles could eliminate the need for a majority of transportation-related gasoline and diesel fuel. This study assumed that gasoline and diesel prices average $3 per gallon, escalating at 3 percent annually through the forecast. Total fuel savings from the projected use of electric cars equal 3.6 billion gallons in 2010, rising to 48.0 billion gallons per year by 2020. Over the 2010 to 2027 period, total fuel savings equal approximately $986 billion dollars, net present value.

Transportation in the United States is responsible for roughly one-third of U.S. carbon dioxide emissions. Converting transportation vehicles to electricity should drastically reduce overall pollutant levels. Assuming a 50 percent reduction in carbon emissions, each electric vehicle would reduce carbon emissions by approximately 2.5 tons annually.[7] Valuing this savings at $10 per ton would provide a $25 benefit per year per vehicle. Over the IRP timeframe, using the Base Case CO_2 emission price would equal a CO_2 emission savings of $11.8 billion present value for the Western Interconnect.

Converting the Western Interconnect fleet of cars and light trucks to electricity would require significant new capital investments. This being said, the study's assumed the replacement rate falls below the natural rate of vehicle replacement in the United States; therefore, the only significant costs resulting from the conversion are the increased costs of electric vehicles versus traditional vehicles and the infrastructure necessary to provide for charging vehicles both at home and away.[8] Table 7.18 details the costs and benefits of the electric car scenario.

Electric vehicles have the potential to provide back-up capacity, reserves and wind integration services. Theoretically, each vehicle would be capable of providing more than 200 kW of instantaneous power to the electrical grid when connected. However, at this rate a vehicle would drain its batteries in approximately 15 minutes. A more conservative estimate for vehicle capacity is 10 kW for cars and 20 kW for light trucks and SUVs, the approximate charging rate of today's technology. At this rate of discharge, each vehicle could provide up to five hours of continuous grid support, though it is unlikely that the electricity industry would need even a fraction of this capability to support the grid. In total, electric vehicles could be capable of providing 1

Table 7.18: Electric Car Scenario Costs ($Billions)

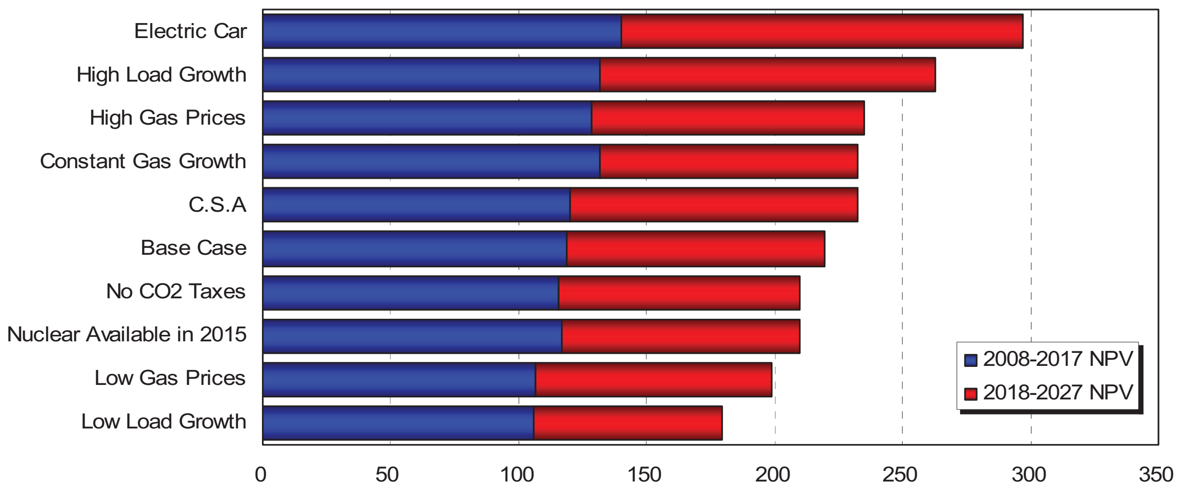
Item	Value
Back-Up Capacity	25
Reserves	10
Emissions	12
Wind Integration	2
Reduced Petroleum Consumption	986
Incremental Car/Truck Cost	-221
New Electricity System Infrastructure (new plants)	-32
Electricity Fuel and O&M	-83
Net Value	**699**
Electricity Industry Benefit	5%

[7] Emissions based on 2005 EIA study. http://www.eia.doe.gov/oiaf/1605/ggrpt/carbon.html. 50 percent reduction in emissions assumption based on 2006 study by Sherry Boschert featured in Plug-in Hybrids: The Cars That Will Recharge America.
[8] This study assumes that the cost of infrastructure for changing the automobile industry over to electric-fueled vehicles only is covered in the cost of those vehicles.

Table 7.19: Future and Scenario Market Price Comparisons ($/MWh)

Scenario	20-Year Levelized Prices		Calendar Year Prices			
	Real 2007	Nominal 2007	2010	2015	2020	2027
Base Case	51.25	60.26	50.79	55.91	70.69	94.86
Constant Gas Growth	58.46	68.82	59.18	69.12	78.45	105.35
High Gas Price	58.32	68.59	58.93	61.76	80.57	82.43
Low Gas Price	43.43	51.03	41.68	47.62	61.44	92.84
High Load Growth	51.57	60.65	50.63	57.37	71.76	94.39
Low Load Growth	50.22	59.05	49.45	54.47	69.76	92.84
Nuclear Available	50.43	59.29	49.38	54.89	69.76	93.87
Electric Car	56.37	66.26	52.03	65.32	81.63	99.65
C.S.A	59.24	69.46	49.42	68.90	92.29	119.89
Unconstrained Carbon	47.56	55.99	50.27	49.35	62.98	85.11

Figure 7.16: Comparison of Total Fuel Costs for the WI in 2017 and 2027 ($Billions)



million MW of grid capacity, approximately three times the total installed capacity of the Western Interconnect in 2020.

Each automobile could be fitted with a device that could respond to system frequency or other signals to allow charging to occur with the following order of preference: (1) meet customer need to maintain a "full tank" of fuel when needed and (2) provide a storage system to meet fluctuating changes on the electricity grid.

Charging is expected to occur mainly during lower-cost off-peak hours of the day, though customers would have the option of charging their vehicles at other times when necessary.

Impacts on the Larger Economy

The Electric Car scenario would have significant impacts on the utility, automobile manufacturing and automotive fueling industries. It would also impact infrastructure at consumers' homes and where they work and play. A number of assumptions are necessary to envision the impacts of the Electric Car scenario. This study is utility-centric and does not attempt to quantify all of the wealth transfers that might occur under the scenario. However, a return of more than one trillion dollars on an investment of $350 billion over 20 years is impressive.

FUTURES AND SCENARIOS SUMMARY TABLES AND CHARTS

A comparison of all of the futures and scenarios run for the 2007 IRP are contained in Table 7.19 below. Total fuel consumption is included Figure 7.16. The large increase necessary to support the Electric Car scenario is offset by even larger reductions in automotive fuel.

AVOIDED COSTS

Avista is obligated to purchase certain third-party generation under the Public Utility Regulatory Policies Act of 1978 (PURPA). Federal law states that such purchases will be at prices equal to avoided cost. State regulatory commissions implement PURPA provisions in their states.

PURPA developers whose projects exceed certain levels are eligible for a negotiated rate based on utility avoided cost, and published rates are provided for smaller PURPA facilities. In Washington, PURPA resources below one MW are eligible for published fixed-rate schedules up to a five-year term. The five-year schedules are tied to forward market prices. In Idaho, facilities up to 10 aMW may obtain published avoided cost rate for up to 20 years.

AVOIDED COSTS VERSUS THE WHOLESALE MARKETPLACE

There is some disagreement within the industry about what specifically constitutes avoided cost. In Idaho, administratively determined avoided cost rates use Avista's next lowest cost investment to set rates. The published figure explicitly includes the cost of installing capacity. In Washington, published rates are based entirely on the forward wholesale market price.

AVOIDED COSTS APPROACH

Avoided costs are a function of energy and capacity cost. Some resources, such as wind, provide little or no capacity. Most coal- and gas-fired plants provide both energy and capacity. Other resources, including hydro and peaking plants, provide a lot of capacity relative to their expected energy generation profile. Both capacity and energy have value. Energy is easily valued by electric market pricing such as the Mid-Columbia index, while capacity valuation is more difficult because there is not an active Northwestern capacity market.

Capacity traditionally has been valued at the cost to build a SCCT plant, even though this plant would provide some energy value over time. The IRP provides a better means of extracting capacity value using the PRSiM Model. As described in Chapter 6, the PRiSM model helps the company select new resources to meet future needs. All of the selected resource options are expected to cost more than the electric market price. The difference in cost between the Preferred Resource Strategy and the energy market price represents an avoided cost for capacity, and the subsequent lowering of future portfolio risk. Capacity value alone can be separated from risk by comparing the cost of the Preferred Resource Strategy to a mix of new resources that ignore portfolio risk.

The lowest-cost portfolio is made up of simple cycle turbines and purchasing green tags to meet the Washington State Renewable Standard. This portfolio is expected to cost $9.32 per MWh over the market price, which represents the capacity value of new generation. The difference between the lowest-cost portfolio and the PRS indicates the value the company and its customers are placing on risk reduction. The risk reduction premium equals $9.39 per MWh. Where a PURPA resource provides both risk and capacity benefits on-par with the PRS mix, the avoided cost payment made under PURPA should equal the cost of the PRS. If a PURPA resource provides more or less value, the payment should be adjusted accordingly.

8. PREFERRED RESOURCE STRATEGY

INTRODUCTION

The 2007 Preferred Resource Strategy (PRS) differs substantially from the company's 2005 plan in three main areas: coal, renewables and gas-fired plants. Avista is no longer willing to rely on traditional coal-fired technologies to meet future customer needs. This reflects recent emissions standards legislation in Washington, imminent federal carbon limiting legislation and higher coal-fired generation costs. There is a lower contribution from wind and other renewables due to: (1) recent legislation promoting renewables in Washington and Oregon that has reduced the amount of cost-effective renewables available by increasing demand for such resources, and (2) wind generation costs have more than doubled over the past six years and increased more than 50 percent since the 2005 IRP. The final change is that natural gas-fired plants have returned to the PRS. Gas resources have not increased as significantly as the other resource options.

The charts and tables presented in this chapter focus on the first 10 years of the plan, as these years are the most relevant for developing our near-term acquisition strategy. All IRP studies were based on 20-year analyses.

Lancaster Generation Facility

CHAPTER HIGHLIGHTS

- Capital costs for coal and wind generation have increased drastically over the past two years; this greatly affects our future plans.
- Coal-fired generation in previous plans is replaced entirely with gas plants.
- Preliminary analyses show that fixed-price gas contracts can reduce year-to-year rate volatility substantially; the PRS "hedges" the portfolio with fixed-price gas even though costs are higher.
- Fewer renewables meet our future loads due to tightening market conditions.
- Conservation acquisition is 25 percent higher than in the 2005 plan and 85 percent higher than in the 2003 IRP.
- The PRS includes 350 MW of gas, 300 MW of wind, 87 MW of conservation, 38 MW of hydro plant upgrades, and 34 MW of other renewables by 2017.
- Lancaster, a currently running CCCT plant, will be available to the utility in 2010.

The result is a PRS that relies primarily on natural gas generation, wind and other renewables. The elimination of coal from our future, combined with reduced contributions from renewable resources opens the possibility of more power supply cost volatility relative to the 2003 and 2005 plans. The costs of these more price-stable resources simply were too high relative to other options. In the absence of a new strategy our customers will be forced to bear this rising volatility. Fortunately, there appears to be an affordable option to reduce the volatility of gas-fired generation resources. We are hopeful that long-term fixed gas contracts will reduce overall volatility. Make special note of Figure 8.13 later in this chapter and consider the superior risk profile of the PRS relative to the "PRS-No Fixed Gas" portfolio. Power supply expenses are reduced significantly for a modest increase in average power supply expense by "locking in" a significant portion of our natural gas supply under long-term contracts. There is a more in-depth discussion of how the company might fix its gas prices for the long term later in this chapter.

The 2007 IRP finds that recent legislation promoting renewables and reducing greenhouse gases and other emissions has driven power supply expenses and customer rates higher than they would be absent these mandates and will continue to do so. While sensitive to and concerned about higher costs that translate into higher rates, we do not oppose society's desire to reduce its impact on global warming and diversify power production away from carbon-emitting sources. This plan simply is intended to inform our management, investors, regulators and customers of the costs of complying with new environmental mandates.

PRiSM DECISION SUPPORT SYSTEM MODEL

As with the 2003 and 2005 IRPs, we continue to use our decision support system software (PRiSM) to help guide resource planning decisions. This differs from the traditional approach many utilities undertake in which a simplified set of resource portfolios is developed to illustrate the impacts of one resource decision over another.[1]

The PRiSM model brings together the value of Avista's existing portfolio of resources, its load obligations and resource opportunities available to meet future load requirements. To capture the optionality inherent in each

Table 8.1: Resource Options Available to Avista for the 2005 and 2007 IRP, First 10 Years

2005 IRP	2007 IRP
Simple-Cycle Gas	Simple-Cycle Gas
Combined-Cycle Gas	Combined-Cycle Gas
Sub-Critical Pulverized Coal	Wind
Critical Pulverized Coal	Biomass
Super-Critical Pulverized Coal	Geothermal
IGCC Coal, Not Sequestered	Cogeneration
IGCC Coal, Sequestered	
Alberta Oil Sands	
Nuclear	
Wind	
Biomass	
Geothermal	
Cogeneration	

[1] The company still develops portfolios, both to illustrate the benefits and costs of certain resource decisions and for comparison to the Preferred Resource Strategy portfolio selected by PRiSM.

of these categories, the results from of the 300 Monte Carlo AURORAxmp runs are considered. Capital, transmission and fixed operations and maintenance costs attributable to each new resource option are evaluated.

PRiSM reviews our existing portfolio and selects an optimal mix of new resources from the available options. A more in-depth discussion of the PRiSM model, and its inputs and outputs, may be found in Chapter 6.

CHANGING POLITICAL ENVIRONMENT

The 2007 IRP responds to major state and federal policy changes to reduce greenhouse gas emissions and encourage development of renewable energy sources. Avista moved away from natural gas-fired resources in its 2005 IRP because of the fuel's inherent price volatility. Recent trends and legislation, such as Washington's Senate Bill 6001 (SB 6001), prevent the company from entering into any long-term financial commitment for resources that exceed a greenhouse gas emissions performance standard of 1,100 lbs/MWh. The bill provides for the standard to be lowered even further after 2012, making compliance even more costly. The emission performance standard effectively precludes the company from acquiring any new pulverized coal plant or a long-term contract with an exiting one, and therefore compels us to rely on natural gas resources. Table 8.1 illustrates the increasingly limited resource options available to Avista in this plan.

These limitations stem primarily from new and expected mandates at the state and federal levels. In the State of Washington, limitations have come from Citizen's Initiative 937 (Energy Independence Act, or I-937), SB 6001, Executive Order No. 07-02 (Washington Climate Change Challenge) and the Western Regional Climate Action Initiative signed by the governors of five Western states. Collectively, the legislation and order seek to decrease greenhouse gas (GHG) emissions, increase employment levels in green energy resources, reduce fuel imports and increase overall renewable generation levels. Oregon has similar renewable and emissions goals and laws in place or in development. Other states throughout the Western Interconnect are also developing or have already enacted GHG reductions and renewable portfolio standards. No RPS or carbon emission standard presently exists in Idaho.

There is a strong regional and national push toward developing a market-based GHG reduction program. It involves several competing cap-and-trade legislative proposals in Congress, as well as an effort to design and implement a regional mechanism to achieve GHG reduction goals. It is also apparent that Congress may enact renewable portfolio standards in the near future. This IRP assumes that there will be GHG constraints and models its Base Case on policy recommendations contained in the National Commission on Energy Policy December 2004 report.

The combination of actual and pending state and national legislation creates considerable uncertainty and novel resource conditions and challenges. First, while the company anticipates that federal GHG and RPS legislation will eventually become law, we can neither accurately predict the final form of these measures, nor can we determine if problems may arise from complying with state and federal mandates governing the same subject matter. At this time, the company can only make general assumptions about future regulatory requirements, with two exceptions: Washington state's I-937 and SB 6001. Second, competition and demand for renewable generating assets has increased substantially since the 2005 IRP, as will be discussed later. That competition is principally a factor of five circumstances:

- RPS requirements, including the accelerated compliance schedule for California's RPS law,
- political considerations associated with pending climate change policies, which, for example, impel RPS-exempt municipal utilities in California to

acquire renewable generating assets even in the absence of applicable mandates,

- the need for resource diversity to mitigate utility exposure to volatile natural gas,
- the ambition of electric utilities to acquire the most economical wind generation sites before they are purchased by competitors, and
- uncertainty about the renewal and duration of federal tax incentives.

Heightened competition for renewable resources has caused a dramatic increase in their cost. Short-term renewals of the federal production tax credit (PTC) also exacerbate the supply and demand balance for wind power as developers try to finish projects before the PTC expires. Lastly, legislation impacts the availability of resources available to serve utilities' retail loads.

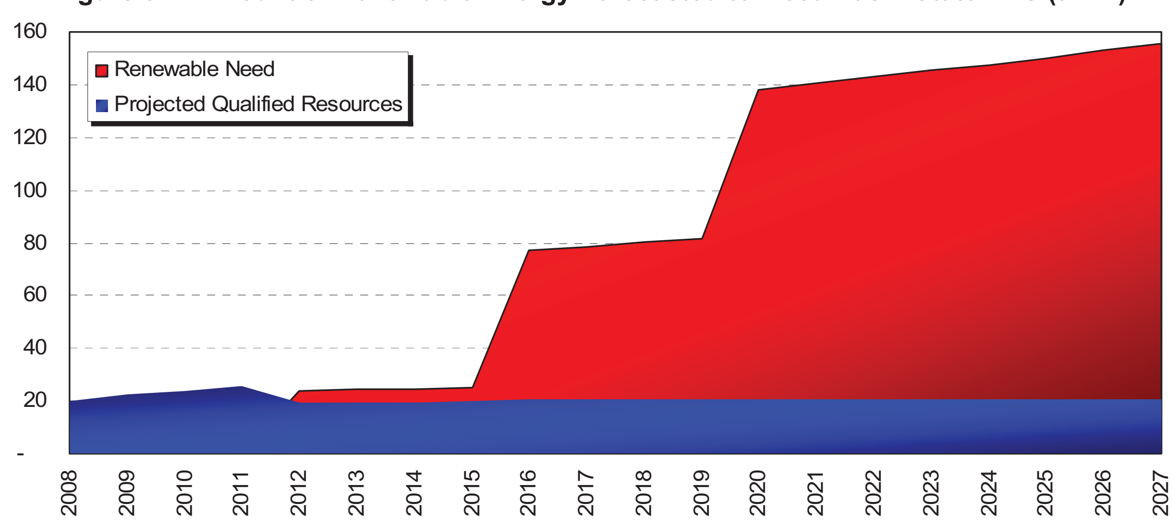
Traditional coal-fired generation provides stable, cost-effective energy that meets more than half of current U.S. power needs. It also emits a tremendous amount of carbon dioxide (CO_2) relative to other generation options. For every MWh a coal-fired plant generates, it emits approximately one ton of CO_2. This is a level three times higher than from gas-fired CCCT plants. In a carbon-constrained economy, traditional coal-fired generation will become expensive as these generators scramble to acquire carbon offset credits, weigh the reduced value of generation against the value of selling carbon offsets into a tight marketplace, or install carbon mitigation technology. Coal-fired technology is also significantly more expensive than forecasted in the 2005 IRP.

WASHINGTON STATE RPS

The passage of I-937 requires all Washington state electric utilities with more than 25,000 customers to acquire new "eligible renewable resources" to meet 3 percent of their energy needs by 2012, 9 percent by 2016, and 15 percent by 2020. Figure 8.1 demonstrates Avista's incremental renewable resource needs. In 2016 more than 80 aMW of I-937 qualifying renewable resources are needed; if met by wind resources alone, it would require Avista to build approximately 240 MW of nameplate capacity. If non-wind renewables options such as biomass or geothermal can be acquired at an attractive price, the required renewable resource capacity will be approximately 90 MW.

Wind generation has thus far proven to be the most commercially viable technology for meeting RPS requirements. It is necessary to acknowledge the

Figure 8.1: Amount of Renewable Energy Forecasted to Meet Wash. State RPS (aMW)



limitations of relying on wind for these purposes. The American Wind Energy Association (AWEA) ranks Washington state 24th in the nation for wind energy potential. Specifically, AWEA estimates the state's annual wind energy potential to be 3,740 MW. By comparison, Montana is ranked fifth with 116,000 MW of annual potential. Montana has approximately 10 times the combined wind potential of the states of Washington, Idaho and Oregon combined. Unfortunately Montana's wind power potential exists east of the Rocky Mountains and therefore is not an "eligible renewable resource" under I-937. This limitation makes compliance more difficult than it otherwise might be. Transferring wind energy generated in eastern Montana westward is also hindered by a present lack of transmission and integration capacity.

The Fifth Power Plan, published by the Northwest Power and Conservation Council (NPCC), estimates the potential wind power capacity of the Pacific Northwest to be approximately 6,000 MW. The NPCC acknowledges that this potential will have a capacity factor between 28 and 30 percent. Most of the economically viable and readily developable wind power sites in the region have already been or are in the process of being acquired. As Pacific Northwest electric utilities proceed to comply with RPS mandates, they will be forced to compete for a diminishing pool of cost-effective wind power sites and to do so within governmentally-mandated periods of time. This is a recipe for even higher renewable resource costs and retail prices in the future.

The limited economic availability of renewable resources poses planning and regulatory challenges for Avista. While we are committed to meeting the requirements of I-937, we are cognizant of the near-term cost impacts of those requirements. The company is also concerned about the potential financial ramifications of failing to proceed expeditiously to acquire renewable resources, lest their cost continue to rise compared to alternative resources. This planning uncertainty is compounded by I-937, which challenges the conventional regulatory paradigm. This law dictates the company's "need" to acquire renewable energy or renewable energy credits. Though the purchase of renewable energy credits would enable the company to comply with I-937, it does not afford us any certainty about meeting renewable energy standards in perpetuity. Renewable energy credit purchases might delay the acquisition of renewable resources to a point in time when those resources are more expensive still.

DECREASED RELIANCE ON RENEWABLE RESOURCES

The 2005 IRP recommended the acquisition of nearly 500 MW of renewable resources between now and 2016, and 750 MW by 2026. Wind resources at that time, though not expected to be inexpensive, were competitive with other options. Other renewable technologies, including geothermal and biomass, were slated to make up nearly 20 percent of the renewable resources contribution in the 2005 plan. The company identified its overall renewables acquisition strategy as a stretch goal.

Wind plant costs have increased by approximately 50 percent since the 2005 plan, a trend that the 2005 IRP identified as then beginning to occur. As described earlier, several factors including RPS requirements have dramatically increased demand for renewable resources. Both higher costs and lower availability have reduced the expected contribution of renewable resources over the first 10 years of the plan from 500 MW in the 2005 plan to below 350 MW (300 MW wind) in this plan; no additional wind is selected, where the 2005 IRP included an additional 350 MW of renewable resources.

To ensure the company has a RPS-compliant portfolio, it is likely that resources will need to be acquired prior to the traditional load and resource balance metric.

Obtaining resources in an environment with significant competition has already resulted in a scramble to obtain the best resources. The company will consider turnkey or power purchase agreements, as well as investing in potential renewable energy sites for future development. We will also consider purchasing qualifying renewable energy credits to meet our statutory obligations.

NATURAL GAS PLANTS RETURN TO THE RESOURCE MIX

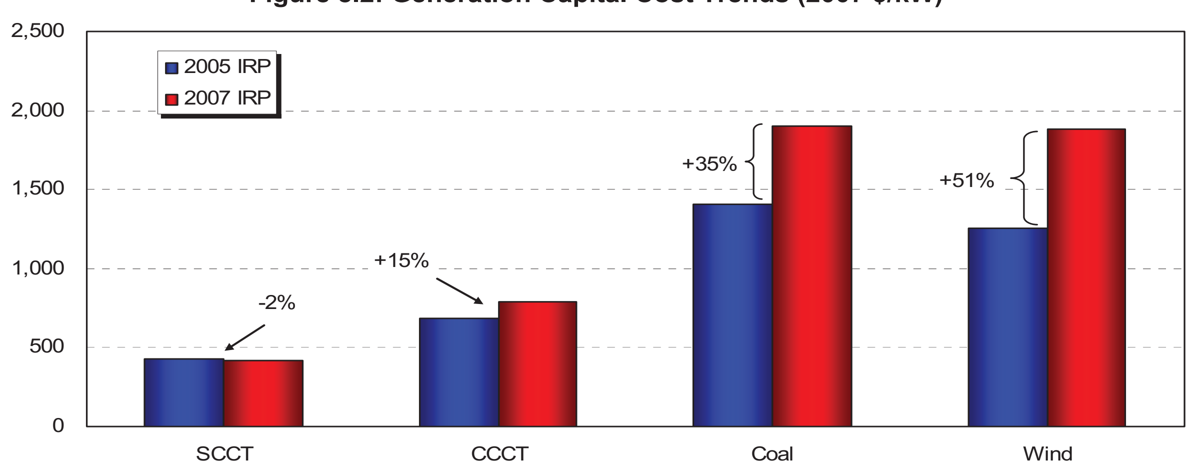
Natural gas prices rose drastically between the 2003 and 2005 plans. Compared to other resource options, namely traditional coal-fired resources, natural gas became both costly and volatile. With a high contribution by wind and other renewables, natural gas was not selected in the 2005 plan. Conditions are different today. Natural gas-fired plant costs have not risen as significantly as other options. In addition, traditional coal-fired technologies are not available to the company in this planning exercise due to recent legislative changes in Washington state. Figure 8.2 compares capital cost assumptions of various resource options in the 2005 and 2007 IRPs.
Rising capital costs make gas-fired generation more attractive because it is a less capital-intensive resource than coal, wind or other renewable options. CCCT generation was forecast in the 2005 IRP to cost approximately $59 per MWh (real levelized 2007 dollars), while the lowest-cost coal-fired option was approximately $42.[2] The 2007 IRP forecasts equivalent costs to be $62 and $61 per MWh for CCCT and Montana-based coal plants, respectively. The gas-fired CCCT cost rose a modest 5 percent overall, even though its capital costs are 15 percent higher than in the 2005 plan; the overall cost increase was lower than the capital cost increase. Coal-fired generation moved in the opposite direction, rising almost 50 percent compared with a 35 percent capital cost increase. Gas represents a comparatively more attractive resource today than it was in 2005, even absent changing social policies.

Though potentially representing a more volatile future when compared to the 2005 PRS, the absence of traditional coal-fired technologies and fewer cost-effective renewables in the 2007 IRP leave natural gas as the major new resource. The 2007 Preferred Resource Strategy includes nearly 350 MW of natural gas-fired CCCT plants in the first 10 years.

DEMAND-SIDE CONSERVATION PROGRAMS UP 25 PERCENT

The 2005 IRP increased DSM by 50 percent over the 2003 IRP, primarily in response to rising market and supply-side resource costs. Studies developed by our conservation groups find approximately 25 percent

Figure 8.2: Generation Capital Cost Trends (2007 $/kW)



[2] Excluding emission costs.

more conservation potential in 2007 than in 2005. The avoided costs against which conservation options are compared continue to rise. As explained above, resource alternative costs are higher in the 2007 IRP. This raises the value of energy saved by conservation measures. Additionally, the 2007 IRP recognizes other factors for the first time that increase the value of this resource; namely capacity value, risk reduction, transmission and distribution savings. These additional factors are inherent in the selection of supply-side resources. The application of new analytical techniques enables the company to assign values for these benefits. Refer back to Chapter 3 for a detailed discussion of the methods we employed and the values assigned to these new benefit categories. The company forecasts it will acquire 87 aMW of conservation over the next decade, thereby reducing the need for new supply-side resources.

SUPPLY-SIDE CONSERVATION EFFORTS CONTINUE

The company continues to explore ways to increase the generation it receives from existing resources and the efficiency with which it is delivered. Upgrades at our Cabinet Gorge and Colstrip plants have increased generation by approximately 20 MW since the 2005 IRP. The company has evaluated numerous upgrade options at its hydroelectric projects over the past two years. This plan incorporates upgrades to the Noxon Rapids hydroelectric project, increasing generation capacity by 38 MW. Future upgrade evaluations will be made considering the same new factors being applied to the conservation resource options.

PREFERRED RESOURCE STRATEGY

SUMMARY AND COMPARISON TO 2005 IRP

The PRS includes wind, other renewable resources, combined-cycle combustion turbines, and supply- and demand-side efficiency improvements. Table 8.2 provides the quantity and timing of proposed resources for the first 10 years of the plan. Comparing this strategy to the 2005 IRP, shown in Table 8.3, this plan moves away from coal toward gas-fired resources, scales down wind due to rising capital costs and lowers the amount of expected capacity from other renewables. More conservation is acquired.

Another key difference between this plan and the 2005 plan is that the first new base load resource enters service

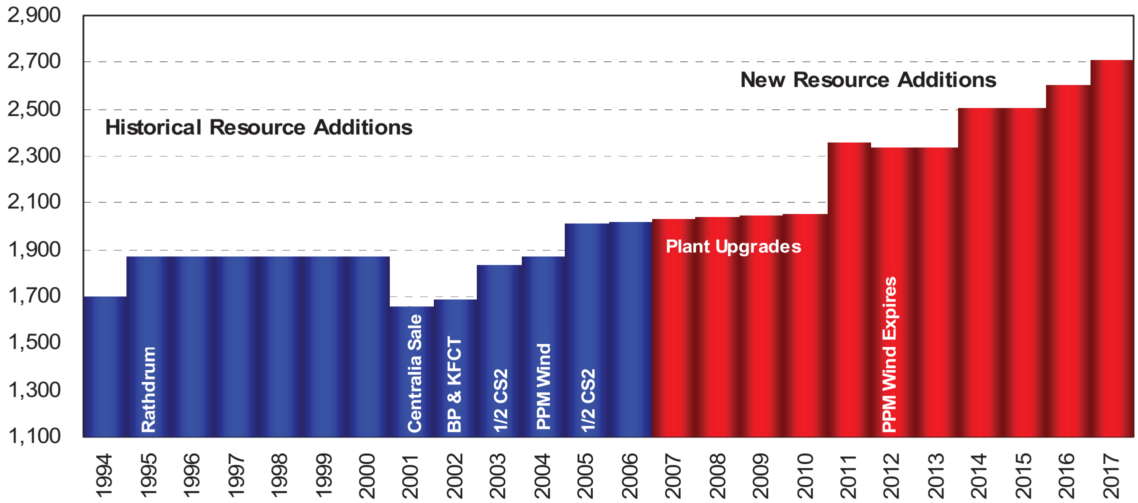
Table 8.2: 2007 IRP Preferred Resource Strategy Selection (Nameplate MW)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
CCCT	0	0	0	280	280	280	350	350	350	350
Coal	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	100	100	200	300
Other Renewables	0	0	0	20	30	30	35	35	35	35
Conservation	6	13	20	27	36	46	56	66	76	87
Total	6	13	20	327	346	356	541	551	661	772

Table 8.3: 2005 IRP Preferred Resource Strategy Selection (Nameplate MW)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
CCCT	0	0	0	0	0	0	0	0	0	0
Coal	0	0	0	0	250	250	250	250	250	250
Wind	0	0	75	150	200	250	325	400	400	400
Other Renewables	0	0	10	20	30	40	50	60	70	80
Conservation	7	14	21	28	35	42	49	56	63	70
Total	7	14	106	198	515	582	674	766	783	800

Figure 8.3: Historical and Future Nameplate Capacity Acquisition (MW)



in 2011 rather than 2012. The 2005 IRP assumed that a coal resource would not be available until 2012, so the 2011 deficit was filled with short-term contracts until that resource was available. This IRP selects a natural gas plant to meet the 2011 shortfall.

RESOURCE ACQUISITION IS LUMPY

PRiSM does not select the Preferred Resource Strategy; rather it informs the utility on the resources that should be selected. The exact PRiSM strategy cannot be used because the model selects resources in perfect quantities to meet resource deficits. It also lacks the ability to quantify all of the experience of Avista's management team. Actual resource acquisition will likely not be so perfect and will be acquired in a lumpy, or stepwise, pattern. Figure 8.3 shows historical and future resource acquision. This chart shows that the company traditionally adds resources in blocks; at times the company has been able to acquire shares of a plant to reduce the dependence on large plant acquision. Figure 8.4 shows the total amount of resources selected by PRiSM's 25/75 risk/cost strategy compared to the PRS. The key difference is that resources added between 2011 and 2013 by PRiSM are added in 2011 as a single block. Resource selections in the second 10 years of the plan are not changed from the PRiSM model selection. Acquisitions in this timeframe will be quantified in future plans. Later in this chapter the PRS will be

Figure 8.4: Lumpy Resource Acquisition (MW)

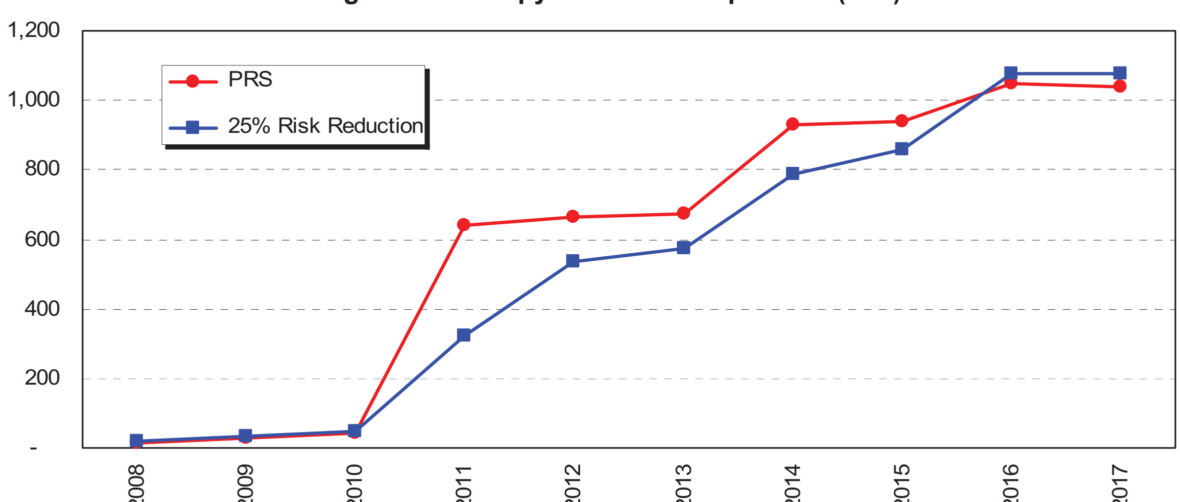


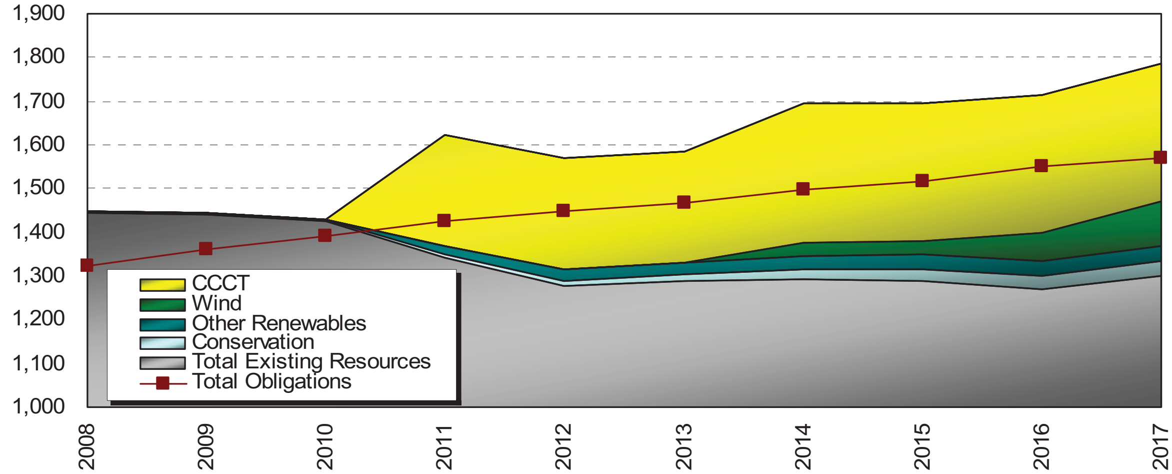
Table 8.4: Loads & Resources Energy Forecast with PRS (aMW)

	2008	2009	2010	2011	2012	2015	2017	2020	2027
Obligations									
Retail Load	1,125	1,163	1,196	1,230	1,256	1,326	1,379	1,450	1,627
90% Confidence Interval	200	199	196	196	192	192	192	156	156
Total Obligations	***1,324***	***1,362***	***1,392***	***1,425***	***1,448***	***1,518***	***1,571***	***1,606***	***1,783***
Existing Resources									
Hydro	540	538	531	528	512	510	509	491	491
Net Contracts	234	234	234	129	107	105	105	106	106
Coal	199	183	188	198	187	187	198	199	186
Biomass	47	47	47	47	47	47	47	47	47
Gas Dispatch	280	295	285	295	280	295	295	280	295
Gas Peaking Units	145	145	141	146	145	146	145	141	145
Total Existing Resources	***1,446***	***1,442***	***1,426***	***1,342***	***1,278***	***1,290***	***1,299***	***1,265***	***1,270***
PRS Resources									
CCCT	0	0	0	253	253	316	316	389	612
Coal	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	33	103	103	103
Other Renewables	0	0	0	18	27	32	32	41	54
Conservation	1	3	5	7	11	26	37	54	103
Total PRS Resources	***1***	***3***	***5***	***279***	***291***	***406***	***487***	***587***	***871***
Net Positions	122	82	38	196	121	179	215	246	359

Table 8.5: Loads & Resource Capacity Forecast with PRS (MW)

	2008	2009	2010	2011	2012	2015	2017	2020	2027
Obligations									
Retail Load	1,703	1,763	1,815	1,868	1,909	2,019	2,103	2,214	2,492
Planning Margin	260	266	272	277	281	292	300	311	339
Total Obligations	***1,964***	***2,029***	***2,087***	***2,145***	***2,190***	***2,311***	***2,404***	***2,525***	***2,831***
Existing Resources									
Hydro	1,142	1,154	1,121	1,128	1,084	1,098	1,098	1,070	1,070
Net Contracts	172	172	173	73	58	58	208	128	128
Coal	230	230	230	230	230	230	230	230	230
Biomass	50	50	50	50	50	50	50	50	50
Gas Dispatch	308	308	308	308	308	308	308	308	308
Gas Peaking Units	211	211	211	211	211	211	211	211	211
Total Existing Resources	***2,111***	***2,123***	***2,092***	***1,999***	***1,939***	***1,954***	***2,104***	***1,996***	***1,996***
PRS Resources									
CCCT	0	0	0	280	280	350	350	431	677
Coal	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0
Other Renewables	0	0	0	20	29	34	34	44	59
Conservation	1	3	5	7	11	26	37	54	103
Hydro Upgrades	0	0	0	0	0	0	0	0	0
Total PRS Resources	***1***	***3***	***5***	***307***	***321***	***410***	***421***	***530***	***839***
Net Positions	**149**	**97**	**10**	**161**	**70**	**53**	**122**	**0**	**4**
Planning Margins (%)	**24.0**	**20.6**	**15.5**	**23.4**	**18.4**	**17.1**	**20.1**	**14.1**	**13.8**

Figure 8.5: Loads & Resources Energy Forecast with PRS (aMW)



compared to other resource portfolios created by PRiSM. In these comparisons the PRS will be represented by the 25/75 risk/cost portfolio to ensure an apples-to-apples comparison (i.e., not biased by lumpiness).

LOAD & RESOURCE TABULATIONS

Preferred Resource Strategy resources balance the company position over time, retaining the lowest possible cost and risk mix of assets to meet customer needs. Table 8.4 and Figure 8.5 illustrate how our present energy positions will be supplemented with PRS resources to meet future load growth. Table 8.5 and Figure 8.6 illustrate the same information for our capacity positions.

The PRS affects the company's mix of resources over time. Today energy needs are met with a mix of resources that is approximately two-thirds fueled by hydro and natural gas. These resources will contribute approximately the same level of energy in 2017; however, hydroelectric generation will fall from 35 percent in 2008 to 29 percent in 2017. Remaining needs in both periods are met by coal, contracts, conservation and renewable energy sources.

Hydro in 2008 represents approximately 50 percent of the company's generating capacity. Gas- and coal-fired plants account for approximately 25 percent and

Figure 8.6: Loads & Resource Capacity Forecast with PRS (MW)

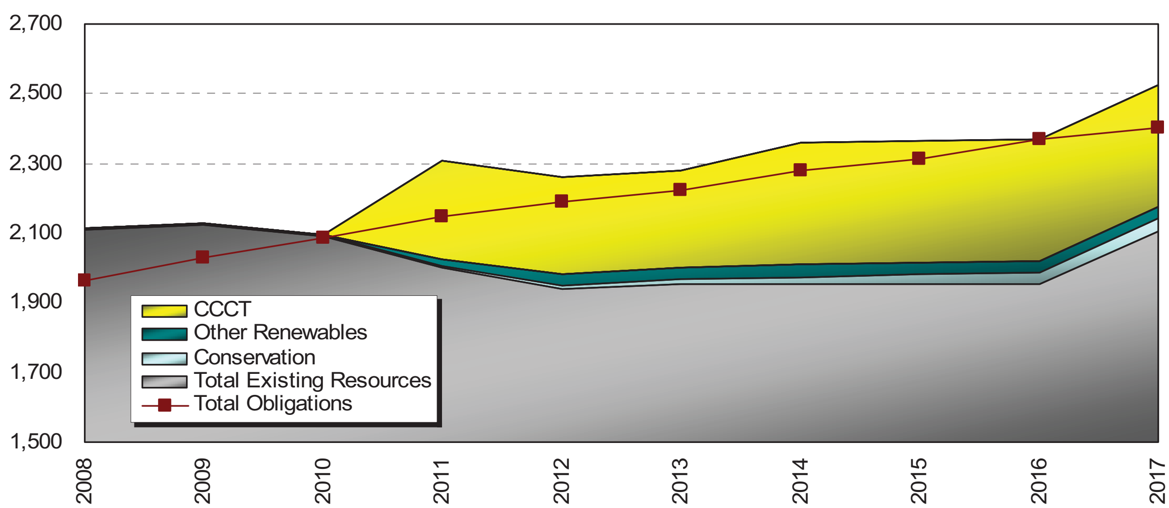


Figure 8.7: Company Resource Mix (% of Energy)

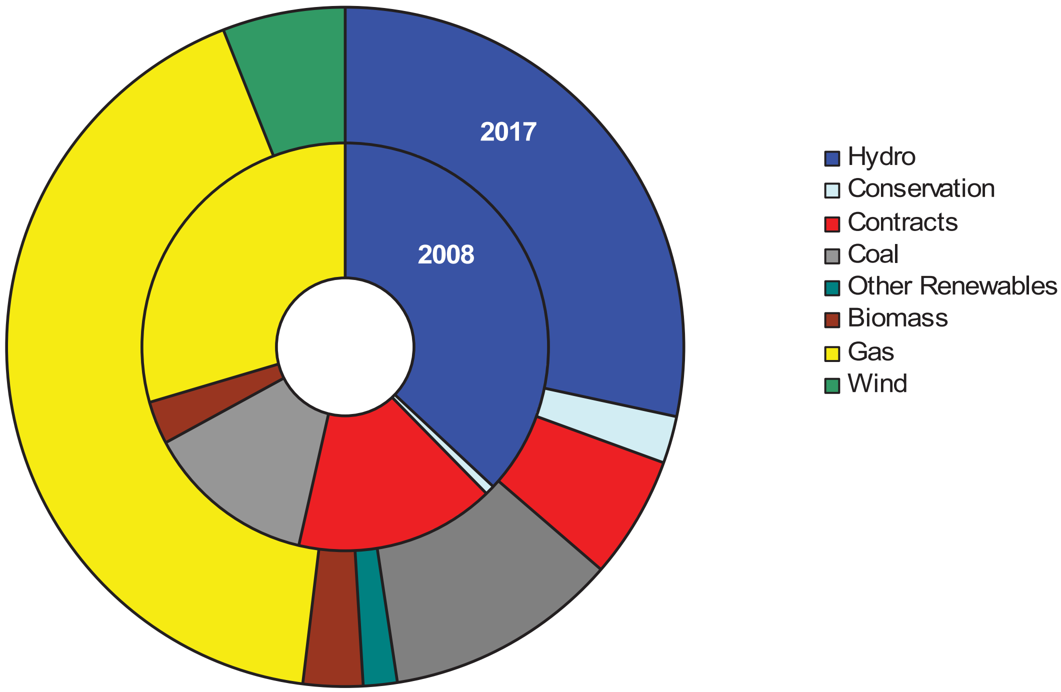
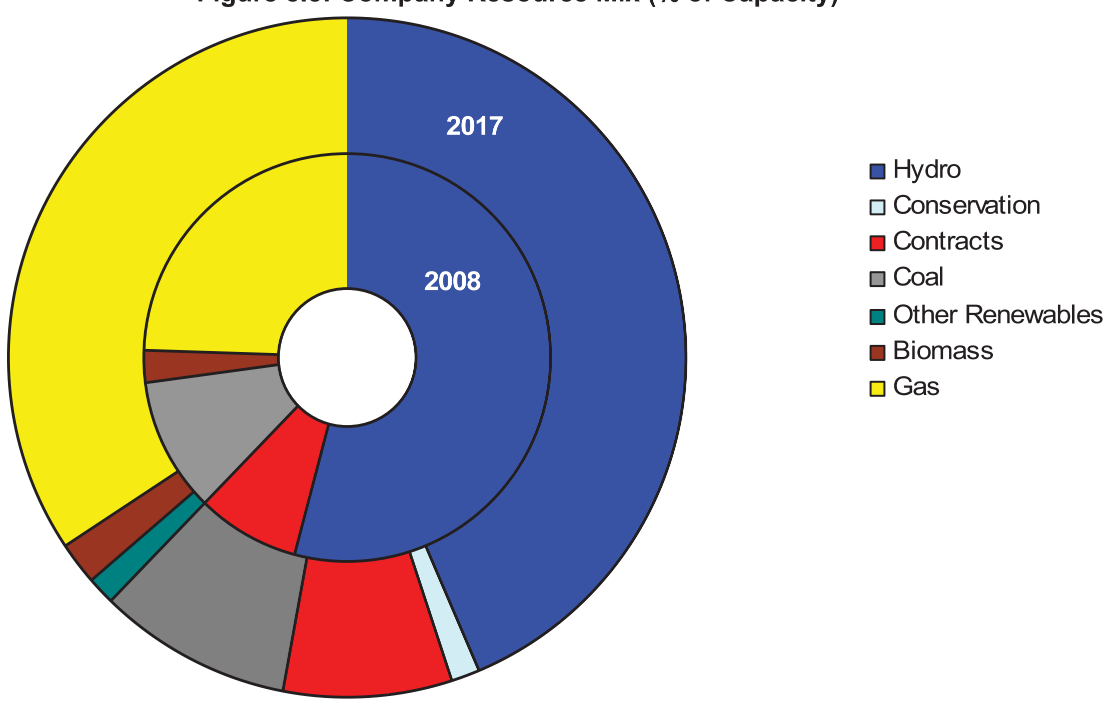


Figure 8.8: Company Resource Mix (% of Capacity)



10 percent, respectively. Contracts and non-hydro renewables complete the capacity mix. The 2017 resource mix is more heavily weighted toward gas-fired generation, as our hydro base does not grow and wind generation is not included in our capacity tabulation. See Figures 8.7 and 8.8 for charts of energy and capacity mixes in 2008 and 2017.

CAPITAL REQUIREMENTS OF THE PREFERRED RESOURCE STRATEGY

PRS capital requirements equal approximately $782 million between 2008 and 2018. This amount could increase by as much as 50 percent when the company finds that the best method for acquiring fixed-price gas involves investments in gas fields, a coal gasification facility and/or other capital-intensive strategies. Table 8.6 illustrates the annual capital investments necessary to support the PRS absent investments in fixed-price gas.

ANNUAL POWER SUPPLY EXPENSES AND VOLATILITY

Power supply expenses including fuel, variable O&M and carbon compliance will grow over time at a compounded annual rate of 9 percent between 2008 and 2017; however, market conditions will likely affect this rate of growth, making some years higher and some lower. This level might appear high to the casual reader, but this figure does not equate to changes in retail rates. Retail rate effects will be mitigated by higher retail sales and lower escalation in non-power supply portions of our business. The IRP forecasts that the average PRS change on per-MWh power supply costs will equal 6.8 percent per year. This increase should translate into even lower retail rate impacts, as non-production costs are expected to increase at a slower rate. Figure 8.9 illustrates forecasted annual power supply expenses from 2008 through 2017.

The trade-off for rising power supply expenses is lower year-on-year volatility. Power supply expense risk decreases as new resources are brought on-line. Figure 8.10 illustrates the falling trend in risk measured by the coefficient of variation of power supply expenses.[3]

CARBON FOOTPRINT

The company has one of the smallest carbon footprints in the United States because of its renewable energy resources. Of the top 100 producers of electric power in the 2006 Benchmarking Air Emissions study by the Natural Resources Defense Council, only seven other utilities have a smaller carbon footprint. The company's carbon footprint is forecast to increase over the IRP timeframe, as it would be nearly impossible to acquire all future resource requirements from non carbon-emitting resources. Our per-MWh emissions will remain essentially flat, and the carbon intensity of our thermal fleet will fall as natural gas plants are added. Figure 8.11 forecasts our carbon footprint explaining that our resources will emit approximately 2.5 million tons of carbon dioxide in 2008, rising to 3.75 million tons by 2017. Figure 8.12 illustrates our emissions on the basis of total sales, total generation, and thermal plant generation. The 2007 PRS emits approximately 6 million fewer tons

Table 8.6: Company Resource Capital Requirements ($ Millions)

Year	Investment	Year	Investment
2008	4.9	2013	60.3
2009	27.3	2014	270.6
2010	98.4	2015	37.5
2011	247.9	2016	249.8
2012	36.2	2017	218.7
		Net Present Value	**781.9**

[3] Coefficient of variation is calculated as the standard deviation of power supply expense divided by the expected (mean or average) power supply expense in each study year.

Figure 8.9: Annual Power Supply Expense ($Millions)

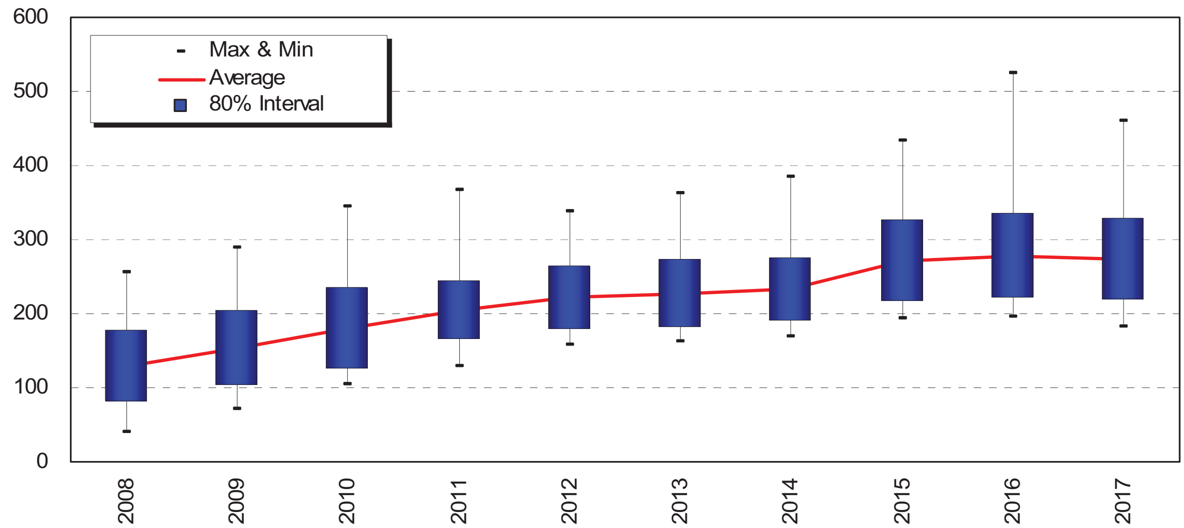


Figure 8.10: Annual Portfolio Volatility (%)

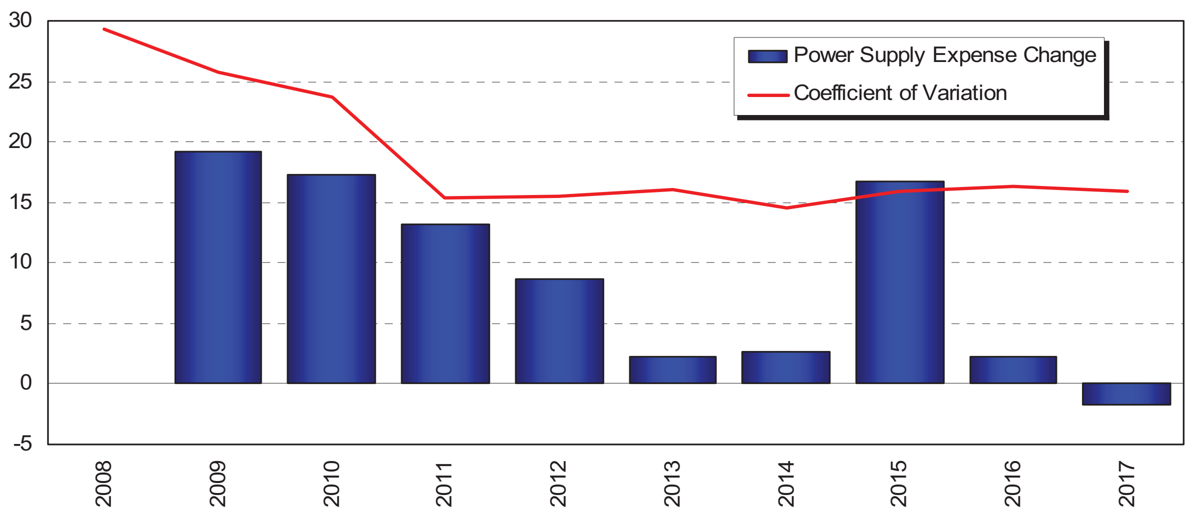


Figure 8.11: Forecasted CO_2 Tons of Emissions (Thousands)

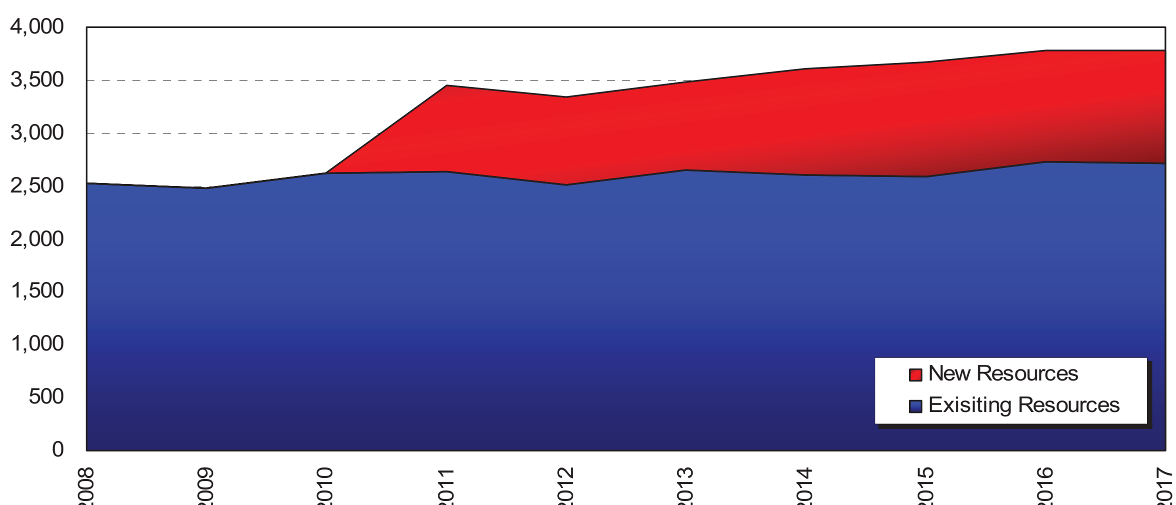


Figure 8.12: Forecasted CO_2 (Tons/MWh)

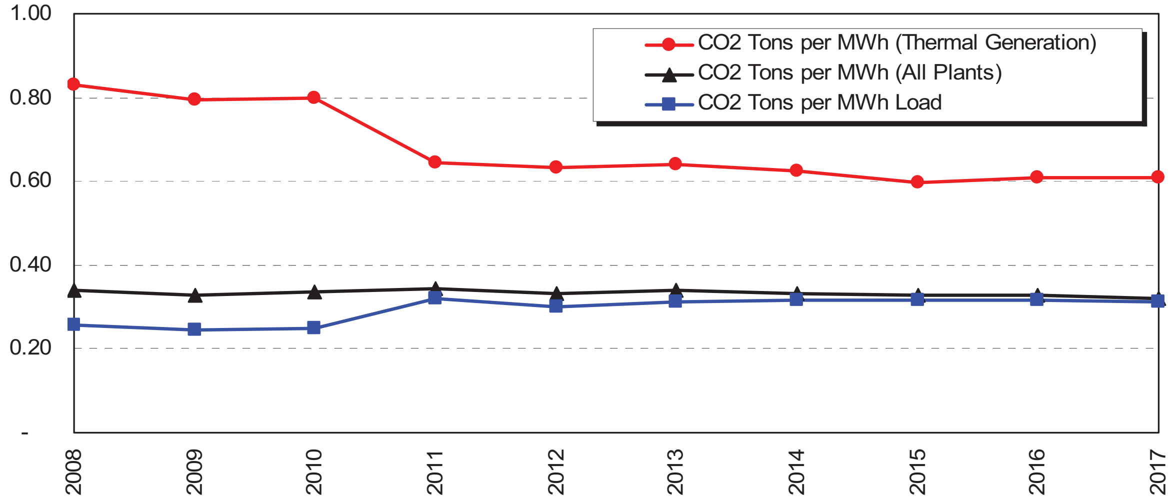
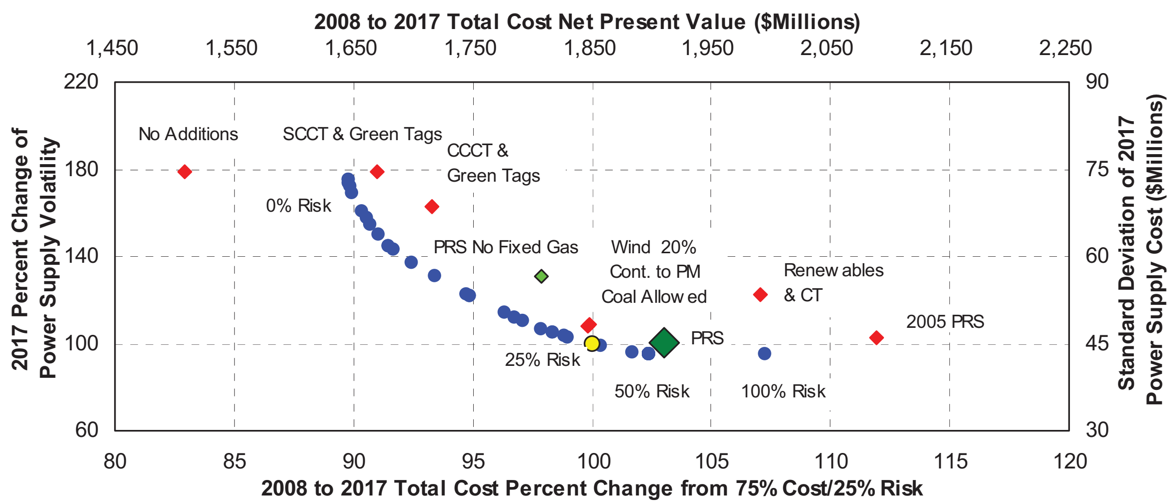


Figure 8.13: Efficient Frontier and Traditional Resource Portfolios



of CO_2 from 2008 to 2017 than the 2005 PRS.

EFFICIENT FRONTIER ANALYSES

When developing a resource portfolio, two key challenges must be addressed—how the portfolio mitigates future costs and how it mitigates year-to-year volatility. An efficient frontier identifies the optimal level of risk given a desired level of costs and vice versa. This approach is similar to finding the best mix of risk and return when developing a personal investment portfolio. As the expected average return increases, so do risks; reducing risk reduces overall returns. Finding the PRS is very similar to this investor's dilemma, but the trade-off is expected average future power supply costs against future power supply cost variation. Figure 8.13 presents the change in cost and risk from the Preferred Portfolio Strategy on the Efficient Frontier. It also shows alternative resource portfolios to illustrate various generic resource strategies. The lower horizontal axis displays the 2008-2017 percent change in the present value of existing and future costs from where the PRiSM model weights its optimization goals 75 percent to cost reduction and 25 percent to risk reduction (75/25 cost/risk). The upper horizontal axis presents actual present value dollars. The right-hand vertical axis shows power supply volatility as a single standard deviation of the average power supply expense. The left-hand vertical axis shows the percent change in 2017 power supply volatility from the 75/25 cost/risk point.

The blue dots represent the efficient frontier of various resource portfolios developed by PRiSM to meet future company requirements. Recall that the PRS is not on the efficient frontier because resource lumpiness is assumed in the first 10 years of the study. It is based on the 75/25 portfolio weighting.

ALTERNATIVE FUTURES

The 2007 IRP studied alternative stochastic futures to measure how the PRS would perform under different assumptions. Figure 8.14 illustrates these differences. This chart is similar to Figure 8.13, but it shows how the efficient frontier would change from the Base Case given the following three futures:

- unconstrained carbon emissions;
- more volatile natural gas prices; and
- high future carbon constraints.

Figures 8.15 through 8.17 provide a more detailed comparison of each future, and display the performance of the various portfolios chosen by the company.

ALTERNATIVE PORTFOLIO STRATEGIES

This chapter details how the company could serve future needs using alternative resource portfolios. It helps benchmark the efficient frontier and the Preferred Resource Strategy. These portfolios, like the efficient frontier, assume the company could acquire resources in perfect increments (i.e., no lumpiness) and that green tags are available to meet the Washington State Renewable Portfolio Requirement. Each portfolio's costs and benefits are compared to the Preferred Resource Strategy. The specific resource contributions for each portfolio are detailed in Table 8.9.

NO ADDITIONS

This portfolio theoretically assumes that the company would not acquire any additional resources and instead would rely on the market for all future capacity and energy needs. Figure 8.18 shows that this is the lowest absolute cost portfolio, however, it has the highest level of risk. Graphically this strategy looks attractive because it sits to the left of the efficient frontier, but it ignores the company's responsibility to adequately meet its customer requirements.

Figure 8.14: Efficient Frontier for All Futures

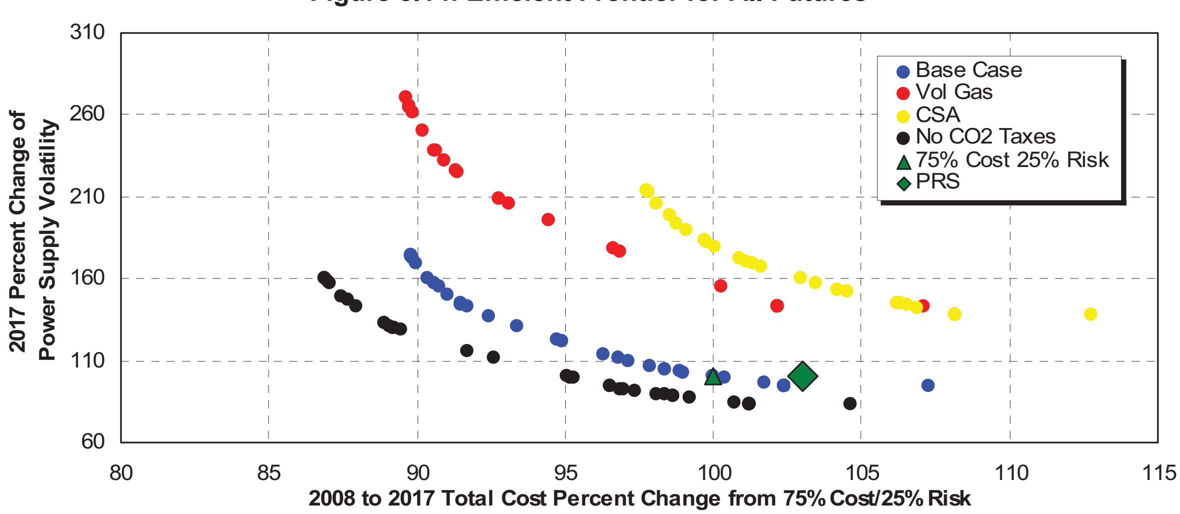


Figure 8.15: Unconstrained Carbon Future's Efficient Frontier Portfolios

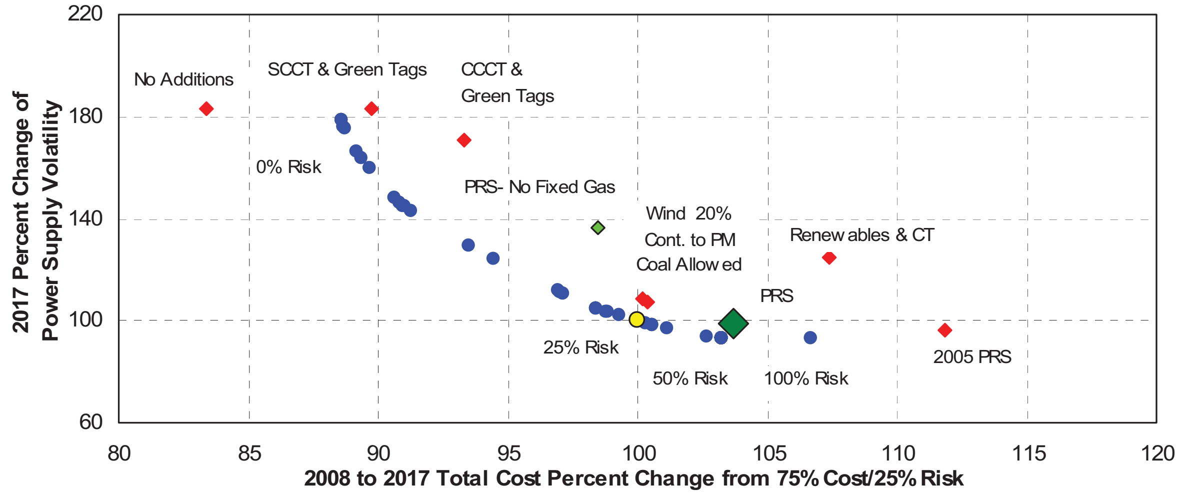


Figure 8.16: Climate Stewardship Future Efficient Frontier Portfolios

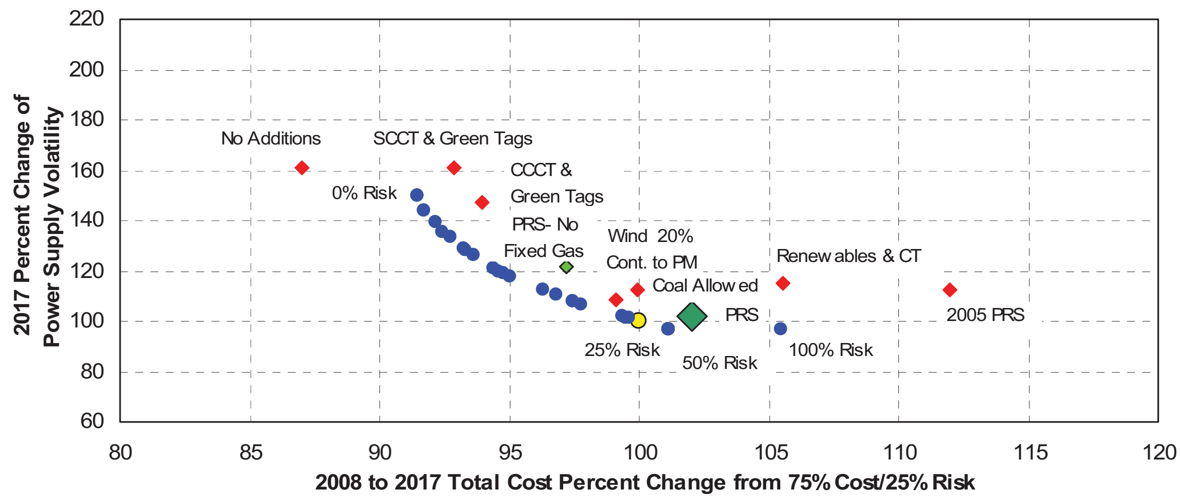


Figure 8.17: Volatile Gas Future Efficient Frontier Portfolios

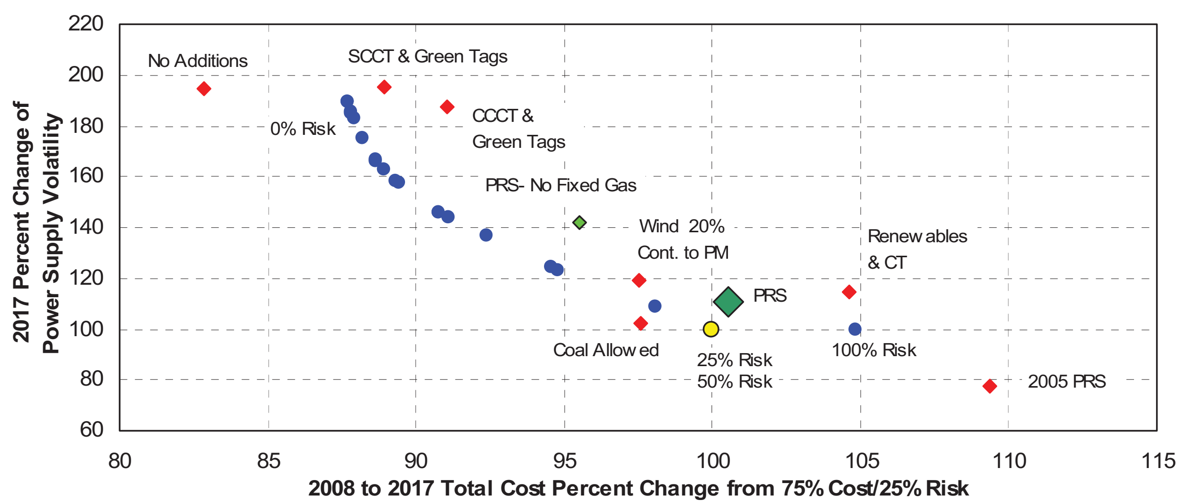
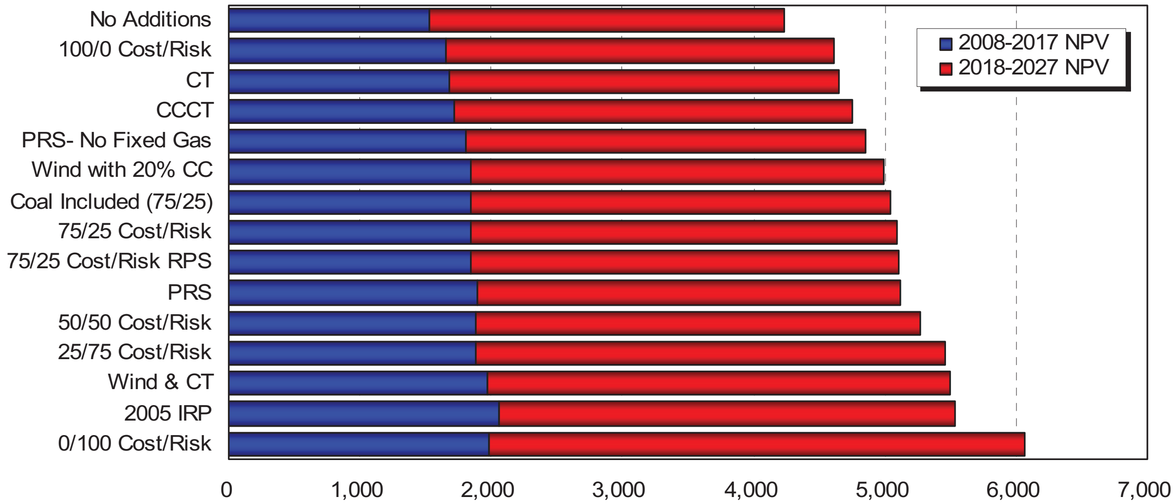


Figure 8.18: Net Present Value of New Resource and Power Supply Costs by Portfolio (2007 $Millions)



SIMPLE CYCLE CTS AND GREEN TAGS

This portfolio assumes that the company would acquire only simple-cycle gas turbines to meet future capacity needs. Given the high operating costs of these plants, this scenario is actually one where future energy needs are met through purchases from the volatile wholesale electricity marketplace. The turbines sit idle a vast majority of the time. The portfolio meets our capacity needs unlike the No Additions Portfolio, but it still contains a high level of volatility due to its heavy reliance on the marketplace and natural gas. The PRiSM model identified the timing of SCCT construction to meet the objectives of this portfolio. Renewable energy requirements are met by acquiring green tags.

COMBINED CYCLE CTS AND GREEN TAGS

This portfolio assumes that the company only acquires combined-cycle gas turbines to meet its capacity and energy needs. The PRiSM model identified the optimal amount and timing of resource additions to meet this portfolio objective. Capacity targets are met and market risk is reduced compared to relying on less-efficient simple-cycle CTs. Green tags meet our RPS requirements.

RENEWABLES AND SIMPLE-CYCLE CTS

Future requirements are met only with renewable resources and simple-cycle CTs in this strategy. The PRiSM model identifies the optimal amount and timing of resources to meet this portfolio objective. SCCTs are included to meet capacity needs, and renewables are added to serve energy needs and reduce risk. This green portfolio requires a 1,200 MW wind penetration level over the next 20 years. Power supply cost variability is reduced in exchange for higher power supply expenses.

COAL ALLOWED

This portfolio allows coal to be selected by the PRiSM model rather than fixed price natural gas plants. The portfolio is based on the same risk level as the PRS. The portfolio is made up of a combination of wind, combined cycle CT, other renewables and coal. Coal is selected after 2013, but not before the 2011 resource need that is met by a combined cycle CT. Because non-sequestered coal is not allowed in our analyses except in this one-off for comparative purposes, this portfolio has a superior performance to the efficient frontier.

Table 8.7: Impacts to Wind & Green Tag Selection (2008-2017)

	With WA RPS	Without WA RPS
Base Case: PRS	300	300
CSA	400	400
Unconstrained CO_2	274 + green tags	274
Volatile Gas	400	400

Table 8.8: Impact to Wind Selection with Idaho RPS (MW)

	With Idaho RPS	Without Idaho RPS
Base Case: PRS	307 + green tags	300
CSA	400	400
Unconstrained CO_2	307 + green tags	274
Volatile Gas	400	400

WIND CONTRIBUTES 20 PERCENT TO CAPACITY PLANNING MARGIN

The IRP assumes that wind generation will provide no capacity to the portfolio in the near- to medium-term. This assumption is based on a wind integration study completed by the company in March 2007. Ignoring this result and assuming a 20 percent capacity contribution for wind makes it much more attractive, though it still sits above the points of the efficient frontier. This portfolio quantifies the impact of the Base Case wind capacity assumptions.

IMPACT OF RPS REQUIREMENTS ON THE PRS

RPS sensitivity portfolios were developed to illustrate the impact of renewable resource cost increases on the level of renewable resources ultimately included in the PRS. The portfolio analysis is based on the 75/25 cost/risk weighting mix, the same as assumed in the PRS. The analysis found that in the Base Case, without a Washington state RPS, the resource strategy would not change under any of the market futures. This indicates that renewables were selected primarily to reduce risk and not to meet the RPS targets. In the unconstrained CO_2 future, fewer renewable resources are built. The model purchases green tags because absent the RPS fewer renewables would be selected. See Table 8.7.[4]

If the company had an RPS requirement in Idaho that mirrored the Washington state requirement, the amount of renewables in our portfolio would not increase significantly. Instead, we likely would purchase green tags, as illustrated by Table 8.8. The RPS would cause the company to build renewable resources that it otherwise might prefer not to.

RISK-ADJUSTED PORTFOLIO STRATEGIES

Portfolios were selected from the Efficient Frontier to illustrate various resource combinations and their performance under alternative market scenarios and futures. Utility-specified portfolios were created to help describe the benefits and risk of certain resource mixes. The portfolios' performances are shown in the figures below.

The charts quantify each portfolio's cost, risk and other factors on a comparative basis. The focus of these charts is on the 2008-2017 time period, but some information is provided for the entire 20-year study. These charts are for the Base Case only. The same information for each market future is provided in the IRP Appendices.

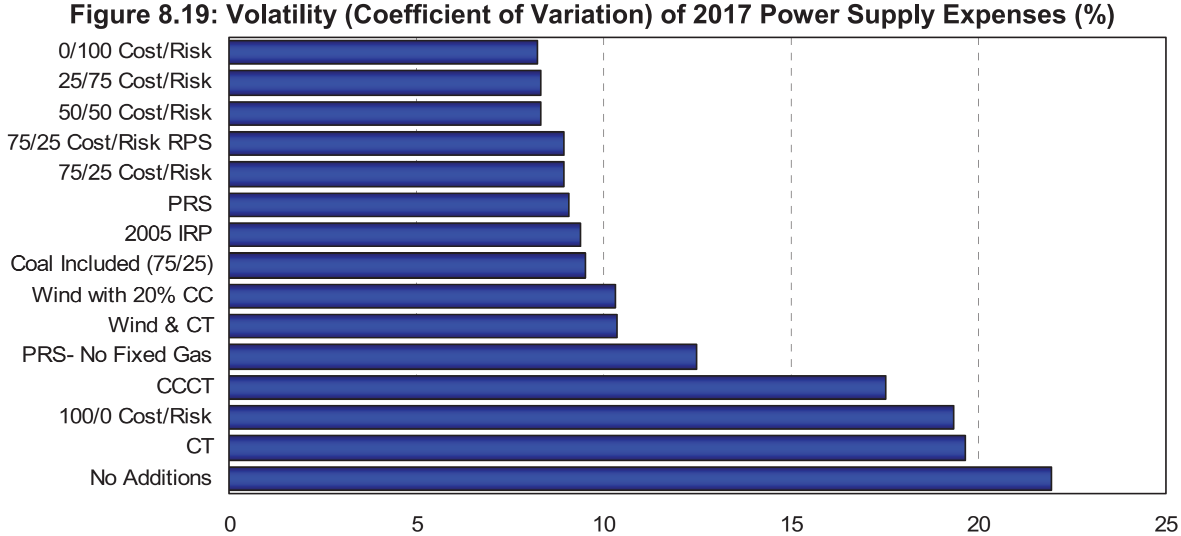
Table 8.9 first provides an overview of the resources included in each alternative portfolio. Figure 8.18 shows the present value of each portfolio's incremental costs,

[4] All cases limit wind to 400 MW of capability between 2008 and 2017.

Table 8.9: 2008-17 Resources for Each Portfolio (Capability MW)

Portfolio	SCCT	Wind	Other Renew-ables	Pulverized Coal	CCCT	DSM	Hydro Upgrades	Total
0/100 Cost/Risk	0	400	35	0	350	87	38	910
25/75 Cost/Risk	0	400	35	0	350	87	38	910
50/50 Cost/Risk	0	400	35	0	350	87	38	910
75/25 Cost/Risk	0	300	35	0	350	87	38	810
100/0 Cost/Risk	363	0	20	0	0	87	38	507
2005 IRP	0	650	140	350	0	87	38	1,265
CCCT	0	0	0	0	384	87	38	509
Coal Included	0	365	35	127	228	87	38	880
CT	382	0	0	0	0	87	38	507
No Additions	0	0	0	0	0	87	38	125
PRS	0	300	35	0	0	87	38	460
PRS w/o fixed gas	0	300	35	0	350	87	38	810
RPS	0	307	35	0	0	87	38	467
Wind & CT	350	675	35	0	0	87	38	1,185
Wind & 20% CC	0	273	35	0	0	87	38	433

Figure 8.19: Volatility (Coefficient of Variation) of 2017 Power Supply Expenses (%)



including new capital and O&M. The costs represented by the blue area of the chart bars are the same as those used on the x-axis of the efficient frontiers.

Risk in the 2007 IRP is measured by the volatility of annual power supply expenses, driven by modeled variations in natural gas costs, loads, emission uncertainty, hydro conditions and forced outages. Figure 8.19 illustrates volatility by displaying the coefficient of variation for each portfolio.[5]

The PRS has lower risk because of the investment into capital intensive and fixed priced assets. The expected power supply costs for 2017 are shown in Figure 8.20. Customer rates will be impacted by new resource investments. Actual rate increases are likely to be lower because power supply expense is only one contributor to rate base. Average power supply cost increases by scenario are shown in Figure 8.21, and the highest single-year increases are shown in Figure 8.22.

[5] The coefficient of variation is calculated by dividing the standard deviation of the total annual cost by the expected power supply cost.

Figure 8.20: 2017 Total Power Supply Expenses ($Millions)

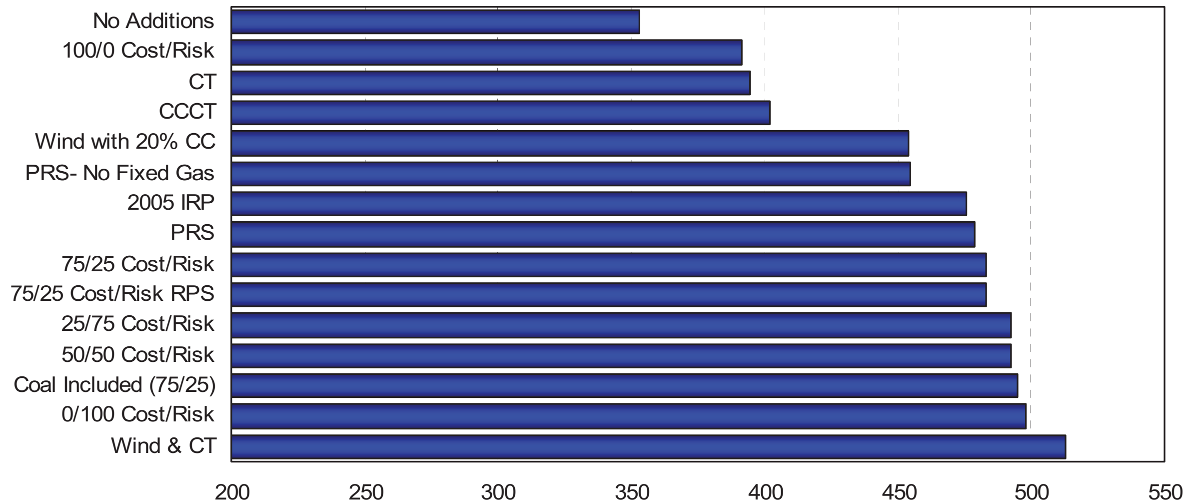


Figure 8.21: Average Annual Power Cost Component Change 2008-2017 (%)

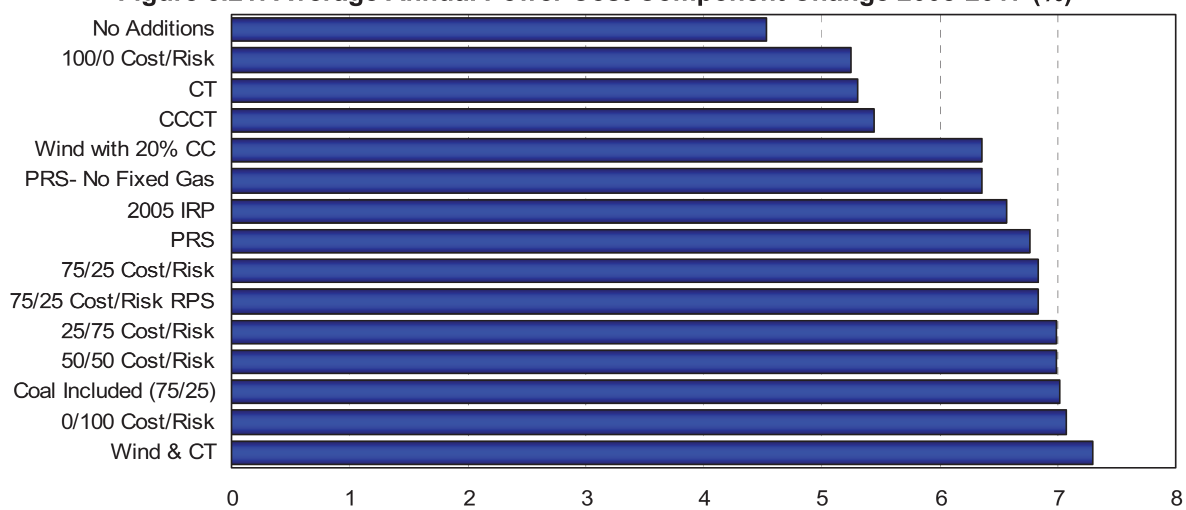


Figure 8.22: Maximum Annual Cost Change for Power Supply (%)

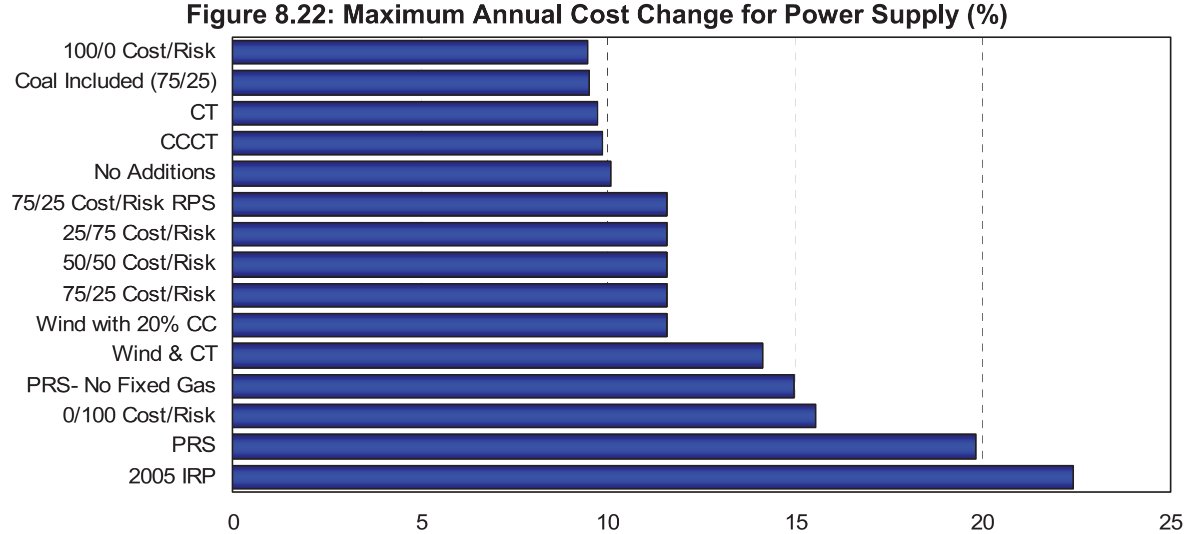


Figure 8.23: 2008-2017 NPV of Capital Investment (2007 $Millions)

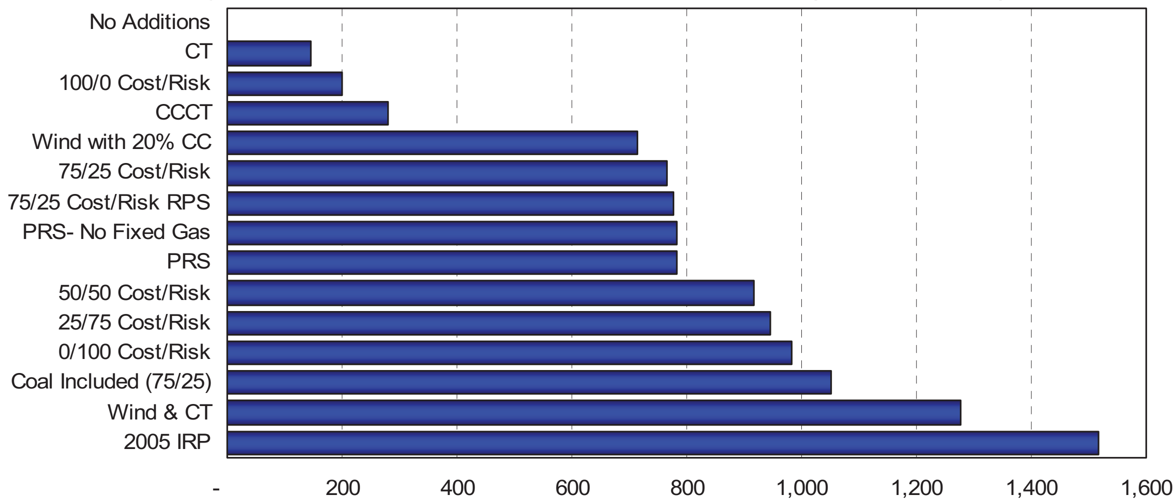
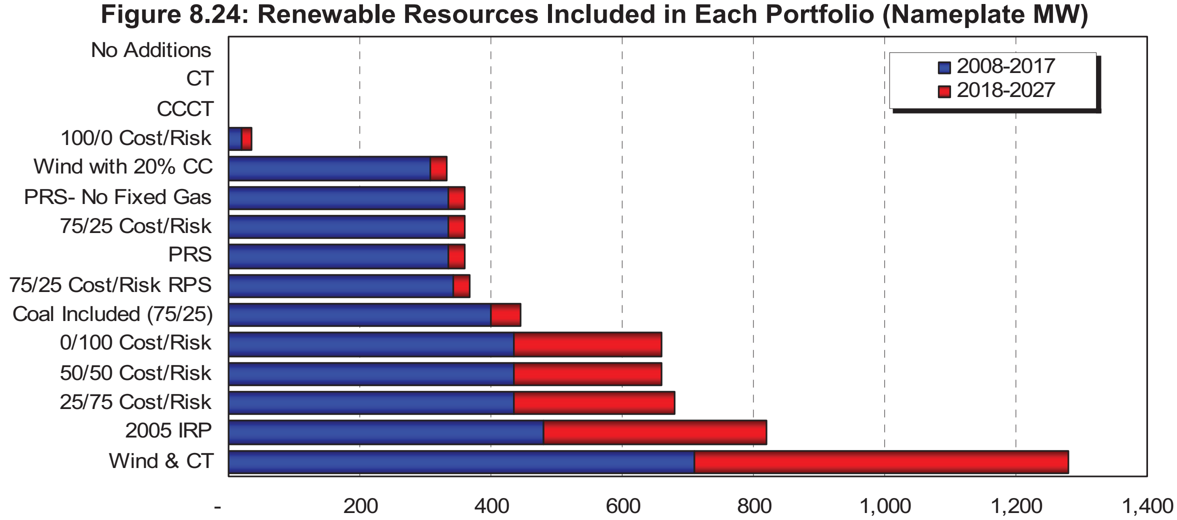


Figure 8.24: Renewable Resources Included in Each Portfolio (Nameplate MW)



Additional capital will be required to meet future load growth. Each portfolio has a unique capital requirement. Figure 8.23 shows the present value of capital requirements for each portfolio option. Capital requirements shown on this chart are for resource capital only and do not include associated capital or debt equivalents needed to firm the price of natural gas as recommended in the PRS.

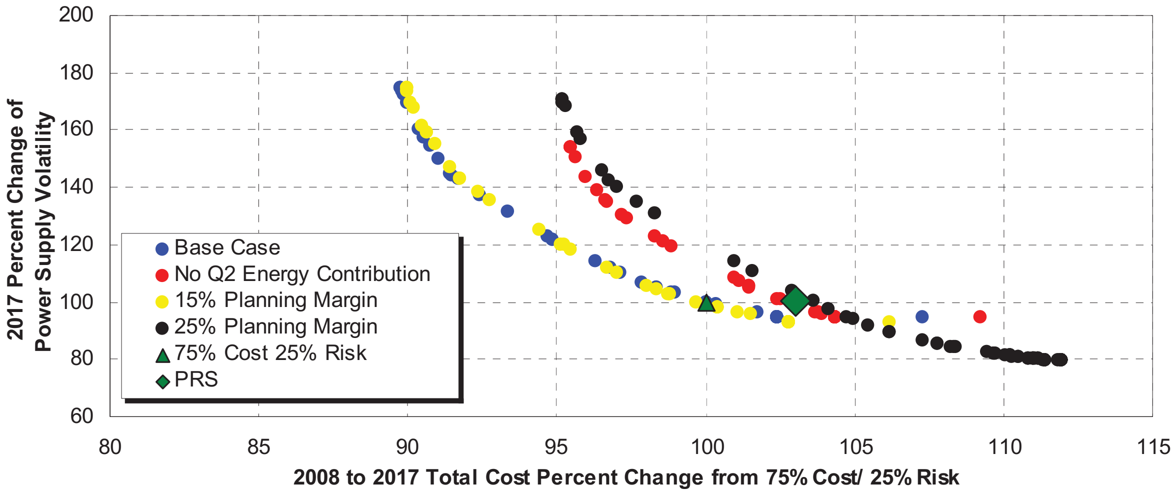
Figure 8.24 presents new renewable resources included in each portfolio between 2008 and 2027. These values are shown in nameplate capacity, not energy or contribution to system planning margins.

PLANNING CRITERIA

The Northwest continues to debate the proper level of planning reserves utilities should carry above their expected peak demand. We also have evaluated eliminating second quarter resource surpluses to ensure that resource deficiencies in the remaining three quarters of the year are not masked by an annual average position covered with excess second quarter hydro energy. This planning level would be similar to moving from an 80 percent to a 95 percent confidence interval planning level.

The PRS currently meets a planning margin equal to 10 percent above expected peak load, plus 90 MW. Energy

Figure 8.25: Alternative Resource Planning Criteria (Efficient Frontier Results)



planning margin is currently based on an 80 percent confidence level of historical hydro and load variance on an annual basis. An analysis was performed to quantify the cost and risk of moving to alternative planning methodologies. Three planning criteria alternatives were modeled:

- 15 percent planning margin;
- 25 percent planning margin; and
- exclude second quarter energy from the annual forecast need.

Each of these alternatives has a different impact on resource acquisition, costs and risks. Figure 8.25 shows the impacts using efficient frontiers. If the company moved to a 15 percent planning margin, there would be little impact on future risks or costs compared to our current methodology. If the company built additional capacity to meet a 25 percent planning margin, as the NPCC recommends in its draft resource adequacy target, costs would probably increase and risk might decrease if the selected incremental resources were one of the lower-risk options. Alternatively, where the company simply met a higher planning margin with market purchases or spot gas-fueled plants, no additional benefit would be seen by moving from a 15 percent to a 25 percent planning margin. Removing second quarter energy surpluses from the company's load and resource position would simply increase costs without a commensurate risk reduction benefit.

CAPITAL COST SENSITIVITIES

Resource capital costs have increased substantially since the 2005 IRP. The largest impact in this plan is a 50 percent reduction in the amount of wind generation stemming from an approximate 50 percent increase in capital costs for wind resources. The Efficient Frontier can illustrate the impact of varying levels of capital cost. Table 8.10 identifies the capital cost sensitivities studied for this IRP. These sensitivities determine how changes would impact not only the cost of the efficient frontier but how our resource selections might change.

The sensitivity results are informative and explain that overall power supply costs change in response to

Table 8.10: Capital Cost Sensitivities ($2007/kW)

Resource	Low	Base Case	High
Wind	1,300	1,884	2,500
Combined Cycle	600	786	1,000
IGCC Coal w/Sequestration	2,500	3,232	N/A
Alberta Oil Sands	2,000	3,963	N/A

Table 8.11: Wind Capacity Selected for 25% Risk Reduction (MW)

	2008-2017	2017-2027
Base Case	300	0
Low	400	200
High	143	0

Table 8.12: Resource Selection Comparison (MW)

	50/50	40/60	25/75	0/100
Base Case				
Other	59	78	66	59
Wind	600	600	600	600
CCCT	677	657	527	350
IGCC w/Sequestration	0	0	130	101
Alberta Oil Sands	0	0	0	226
IGCC @ $2,500/kW				
Other	59	78	78	59
Wind	600	600	600	600
CCCT	0	0	0	280
IGCC w/Sequestration	0	66	299	101
Alberta Oil Sands	0	0	0	226
Oil Sands @ $2,000/kW				
Other	59	59	78	59
Wind	600	600	600	600
CCCT	467	451	350	350
IGCC w/Sequestration	0	0	0	101
Alberta Oil Sands	210	226	226	226

varying capital cost levels; however, the variations did not significantly change the overall strategy during the first 10 years of the plan. The one exception is where wind costs vary significantly. See Table 8.11. Lower wind acquisition is offset by more green tag purchases.

Sequestered IGCC coal and Alberta Oil Sands would be selected at the expense of gas resources if their capital costs were to fall significantly from what is assumed in the Base Case. See Table 8.12.

FIXED GAS PRICE

Coal-fired generation accounted for a significant portion of the Avista's PRS mix in both the 2003 and 2005 IRPs. Coal-fired plants provide a hedge against volatile electricity and natural gas prices because 60 percent or more of their costs are fixed through large capital investments. Variable operating and fuel costs at a coal plant are modest compared to gas-fired resources. A resource profile containing coal contributes to stable power supply expenses.

The cost of operating gas-fired resources, on the other hand, is highly correlated with the electricity marketplace. Natural gas prices are very volatile. The fixed costs of natural gas plants are low relative to their all-in cost of generation, approximately 20 percent, reflecting a low capital investment. Utility portfolios with large concentrations of gas-fired generation suffer from rates that are less stable than utilities that rely on other sources of generation.

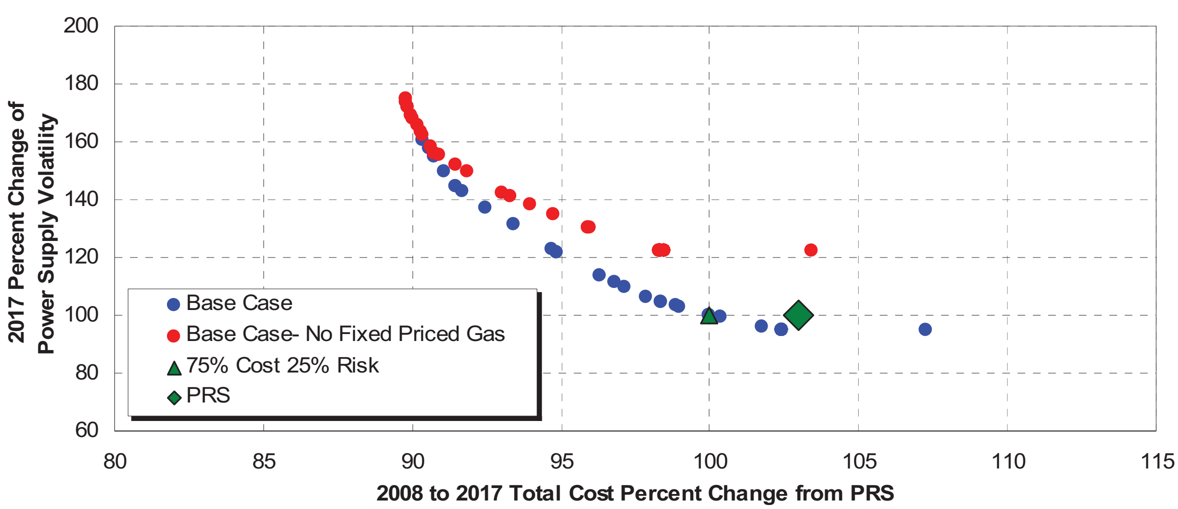
Gas-fired plants have not experienced the same capital cost increases seen in new coal-fired plants. In fact, recent experience by Avista (Coyote Springs 2) and Puget Sound Energy (Goldendale) indicate that independent power producers in the Northwest marketplace are willing to sell their gas-fired plants at prices below the green field costs assumed in this plan. The enactment of new laws imposing emission performance standards on fossil-fueled generation resources acquired by electric utilities in Washington and California will narrow base load technology options, at least in the short-term, to gas-fired generation. This restriction, coupled with regional load growth and the prospect of additional greenhouse gas regulations on fossil-fueled generation resources, particularly coal-fired generation, may ultimately increase demand for and the cost of gas-fired plants.

Locking in natural gas costs through a long-term fixed-price contract, an investment in a pipeline-quality coal gasification plant, an investment in gas fields or through other means makes a gas-fired combined cycle combustion turbine (CCCT) behave financially like a coal-fired resource. Variable costs are greatly reduced and are much less volatile because a significant portion of its largest variable component—gas fuel—is not tied to the natural gas market. In both high and low gas market conditions the price paid by customers is the same. In years where natural gas prices are high, the fixed-cost contract looks very attractive financially and customers pay less than if the company relied on shorter-term purchases. On the other hand, years with low natural gas prices make the fixed-cost contract look financially unattractive compared to a short-term purchase. Over time, the long-run cost of operations with fixed-price gas should parallel the cost of operations where a gas plant is fueled with short-term gas.

Fixing gas prices does not lower absolute cost, but it does limit price volatility. As with any long-term fixed price option, prices over time likely will be higher than if the company relied exclusively on spot market gas purchases. Asking a third party to absorb price risk always entails a premium in exchange for accepting that risk. This is similar to purchasing an automobile insurance policy. A policy is not purchased to lower driving costs but to decrease the amount of financial risk to the driver if an accident were to occur. A financially-fixed natural gas price would be higher than average spot market gas purchases, but that premium would limit the upside exposure of the company and its customer to gas price spikes.

The company has identified three potential avenues to lower natural gas price risk. There might be more. The first, and most probable option, would involve purchasing a long-term fixed price gas contract. Until recently, the market did not offer these types of contracts because of experiences in the 2000/01 energy crisis. Recent

Figure 8.26: Efficient Frontier With and Without Fixed Price Gas Contract Option



informal market surveys have found sellers offering terms up to 20 years. A second option would involve investing in a gasification plant to convert coal to pipeline-quality gas. A third option would be investment in a gas field.

The company tested the benefits of fixed price contracts with PRiSM and found a general preference for fixed price gas because of its ability to reduce risk. Even with premiums as high as 75 percent above the short-term gas prices, the PRiSM model selects fixed-price gas for a portion of the preferred portfolio. In the Base Case, where a 30 percent fixed gas price premium is modeled, risk is reduced by approximately 20 percent, as shown in Figure 8.26.

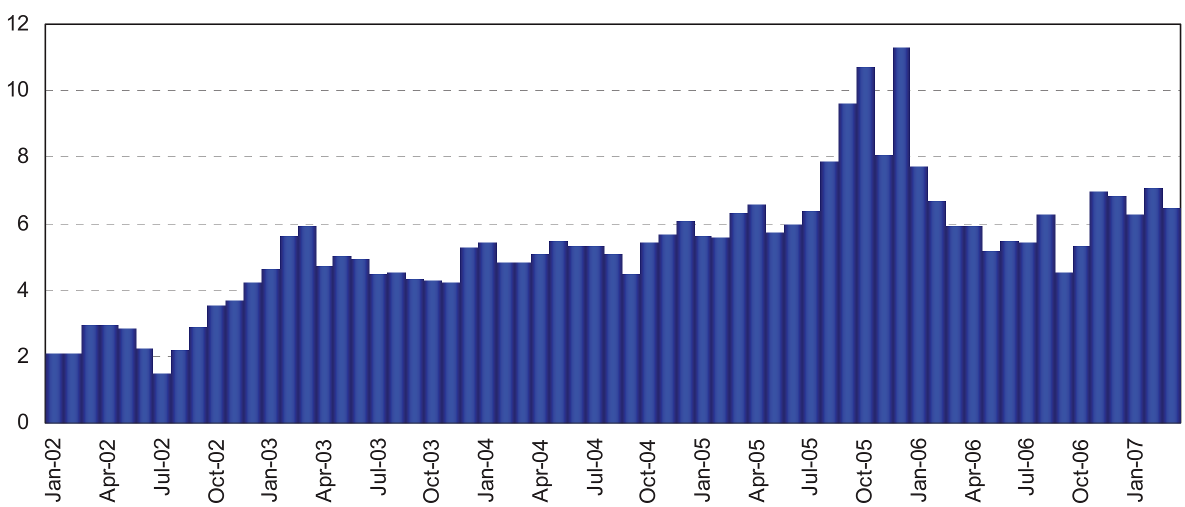
AN EMPIRICAL EXAMPLE

Avista has historically purchased fuel for our gas-fired plants in the short- to medium-term markets, making purchases from time periods as short as one day up to 18 months into the future. Generation costs have varied greatly over this time with the price of natural gas. Figure 8.27 illustrates historical monthly natural gas prices at the Stanfield hub, where Coyote Springs 2 procures its natural gas. Prices are shown from January 2002 through March 2008.

As shown, gas prices have been quite volatile. Gas prices ranged from a low of $1.52 per Dth to a high of $11.29 per Dth. Translated to monthly gas expense, a company model shows the cost ranges from zero in four months, where market conditions did not support operating the plant, to as high as $14.4 million in December 2005.[6] The standard deviation of this hypothetical cost stream is large, at $2.9 million, or 62 percent of the average.

Greater reliance on gas-fired generation has the potential to introduce significantly more volatility in company power supply costs than has been witnessed in the past. The first ten years of the PRS acquires 350 MW of CCCT capacity, more than doubling the size both of our CCCT fleet and gas purchasing budget. To illustrate, a $1.72 per Dth annual increase in natural gas prices would drive up fuel expenses by approximately $21 million at Coyote Springs 2; with an additional 350 MW of gas-fired CCCTs, the exposure would be $48 million.[7] The largest annual swing in gas prices over this period was

Figure 8.27: Historical Monthly Gas Prices at Stanfield ($/Dth)



[6] Assuming theoretical operation absent both maintenance and forced outage costs.
[7] $1.72 per Dth equals one standard deviation of annual Stanfield natural gas prices between 2002 and 2006. Price swings would be expected to exceed this amount in one in three calendar years. 160 dth/MW * 280 MW * 365 days * 75 percent capacity factor * $1.72/Dth = $21.2 million; 160 dth/MW * 630 MW * 365 days * 75 percent capacity factor * $1.72/Dth = $47.8 million.

$2.22 per Dth between 2002 and 2003. Reviewing the 2002 through 2006 period, history shows a $48.4 million range in annual gas procurement costs, and a maximum year-on-year change of as much as 50 percent. Hedging a portion or all of our natural gas purchases might reduce fuel expense volatility by 50 percent where the 2002 through 2006 years provide guidance.[8]

DECIDING THE QUANTITY OF NATURAL GAS TO HEDGE

One challenge of fixing natural gas prices is deciding how much of a plant's portfolio should be hedged. Should all expected generation be hedged? Should the hedge be placed equally across all months of the year, or differently in each month to reflect expected generation levels? As discussed earlier, fixing gas prices likely will incur higher average cost. This is illustrated by Figure 8.28. The lowest average cost is where the plant does not hedge any of its gas costs with fixed prices. The mean variable fuel cost of the plant is approximately $40 per MWh, with a range of $10 to $85 in any given year of the study. Hedging 25 percent of natural gas consumption reduces the expected range of operating costs by about a third, but raises the average variable fuel cost of the plant to about $45 per MWh. Hedging 75 percent of natural gas consumption tightens the distribution of costs by 75 percent, but it also increases expected variable fuel costs to $54 per MWh.

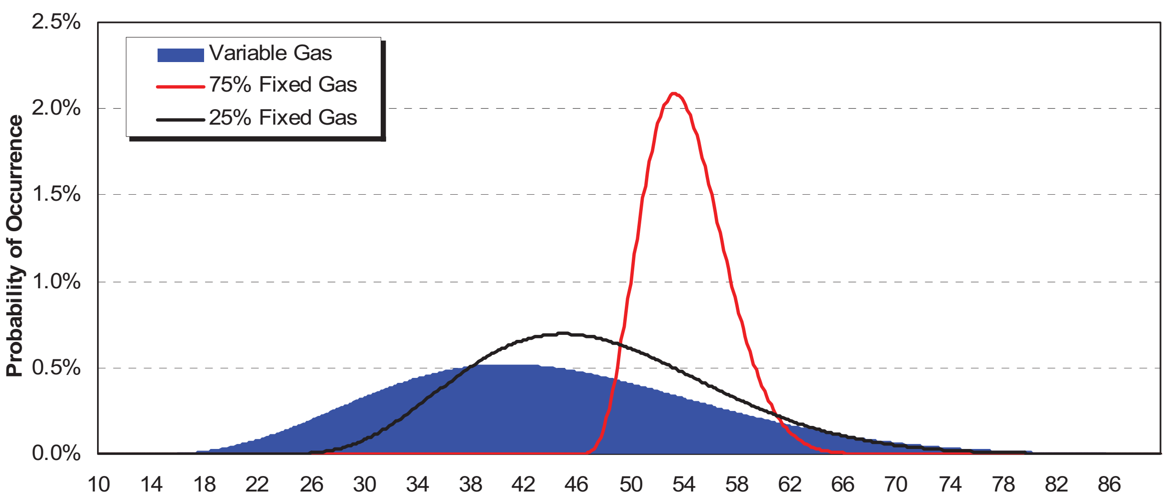
The answer to this question is too broad for resolution in an IRP, and the company will further analyze the question as part of its action plan. The IRP took a simpler approach and assumed that the natural gas price was fixed for 75 percent of annual average expected generation.

More analysis of fixed price options is necessary to confirm that a fixed price gas strategy is in the best interest of our customers. This work is included as an action item for the 2009 IRP.

PORTFOLIO PERFORMANCE ACROSS MODELED SCENARIOS

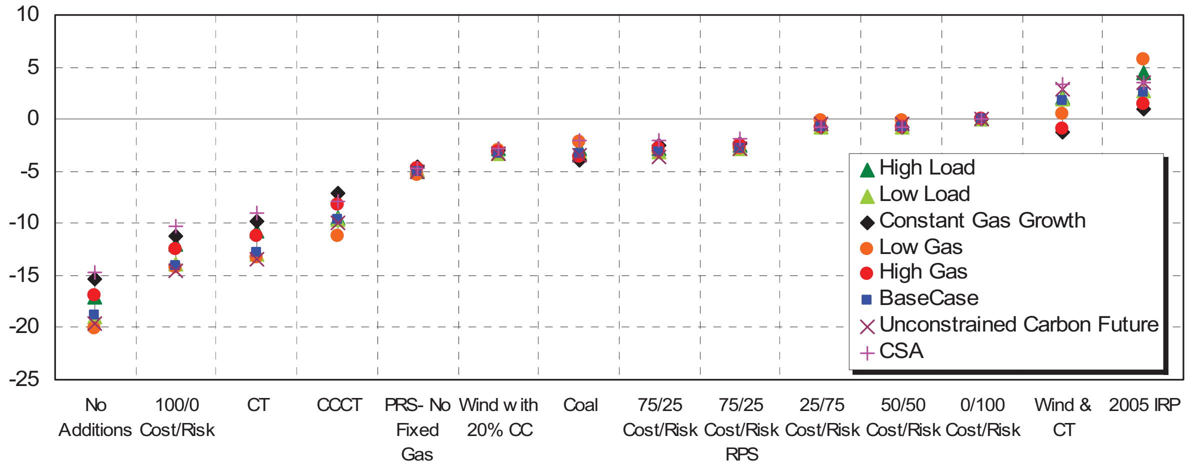
Resource portfolios perform differently in the different market scenarios detailed in Chapter 7. For example,

Figure 8.28: Variable Fuel Costs of CCCT Plant at Various Gas Hedging Levels ($/MWh)



[8] This analysis is based on dispatching a CCCT plant during the years 2002-06 using daily average Mid-C and Stanfield natural gas prices. In the case of fixed price gas, fixed price gas was assumed to be purchased in an amount equal to 75 percent of the annual operating capability of the unit, approximately the level of operation the company would expect out of a CCCT plant. Purchasing between 60 and 75 percent of annual capability provides a similar result. The fixed price was set equal to the average price over the 5-year period. On days in which the plant operated, the remaining 25 percent of needs not covered by the fixed purchase was purchased at the daily index price. On days in which the plant was not economical to run, gas was sold into the spot market. Change in volatility is defined as the change in the standard deviation of fuel expense.

Figure 8.29: Portfolio Cost Comparison Versus PRS for Each Market Scenario (%)



portfolios including higher concentrations of carbon-emitting resources will perform poorly in a high-cost carbon environment when compared to portfolios not relying as heavily on them. The expected costs of gas-reliant portfolios will vary more under low and high gas scenarios than portfolios not relying on gas. The performance of various portfolios studied in the plan is displayed in Figure 8.29. The figure explains how the different portfolios compare relative to the Preferred Resource Strategy, when measured by the 2008-17 NPV of total power supply expenses. For example, the "No Additions" portfolio is expected to cost as much as 20 percent less than the PRS (shown in this chart as the "25/75 Cost/Risk" portfolio) portfolio under the Low Gas market scenario. The alternative's savings from the PRS fall to 15 percent in the Constant Gas Growth scenario.

Figure 8.29 identifies which portfolios are on average lower and/or more costly than the PRS, and show which portfolios' expected average costs are more volatile compared across the market scenarios. Riskier portfolios have a larger cost range while the performance of less risky portfolios does not vary much.

Risk across scenarios is not the same risk being measured in the efficient frontiers displayed in this section. Scenario and paradigm risks help explain how robust portfolios are where significant changes from the Base Case occur. Risk measured by the efficient frontier is how well the portfolio behaves under varying stochastic parameters (i.e., natural gas, forced outage, carbon price, and wind and hydro variations). The PRS-No Fixed Gas portfolio best illustrates this difference. When shown in Figure 8.29 it appears that the PRS with no fixed gas performs exceptionally well across the scenarios while providing five-percent lower average costs than the PRS. But in looking back at the efficient frontier of Figure 8.13, not fixing gas prices actually creates a higher risk profile than the PRS (by approximately 35 percent) in the expected Base Case due to the portfolio's greater exposure to shorter-term variations in natural gas prices.

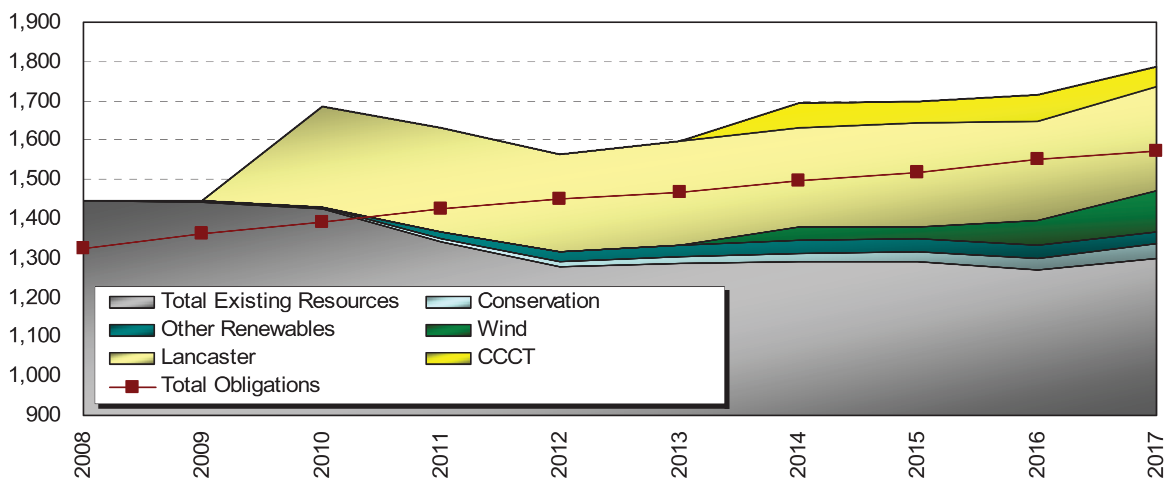
THE LANCASTER GENERATION FACILITY

The company announced the sale of its energy marketing company, Avista Energy, in April 2007. As part of this transaction Avista Energy's tolling contract for the Lancaster Generating Plant output will become available to the utility beginning in 2010. The announcement came after we had substantially completed our IRP analysis and PRS. Given that Lancaster is the same technology as the 280 MW gas-fired combined cycle resource identified in the PRS at roughly the same timeframe and is available to the utility, the resource

Table 8.13: Loads & Resources Energy Forecast with PRS (aMW)

	2008	2009	2010	2011	2012	2015	2017	2020	2027
Obligations									
Retail Load	1,125	1,163	1,196	1,230	1,256	1,326	1,379	1,450	1,627
90% Confidence Interval	200	199	196	196	192	192	192	156	156
Total Obligations	***1,324***	***1,362***	***1,392***	***1,425***	***1,448***	***1,518***	***1,571***	***1,606***	***1,783***
Existing Resources									
Hydro	540	538	531	528	512	510	509	491	491
Net Contracts	234	234	234	129	107	105	105	106	106
Coal	199	183	188	198	187	187	198	199	186
Biomass	47	47	47	47	47	47	47	47	47
Gas Dispatch	280	295	285	295	280	295	295	280	295
Gas Peaking Units	145	145	141	146	145	146	145	141	145
Total Existing Resources	***1,446***	***1,442***	***1,426***	***1,342***	***1,278***	***1,290***	***1,299***	***1,265***	***1,270***
Net Positions	**121**	**79**	**33**	**-83**	**-170**	**-228**	**-272**	**-341**	**-513**
PRS Resources									
Lancaster	0	0	254	264	249	264	264	228	0
CCCT	0	0	0	0	0	52	52	162	612
Coal	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	33	103	103	103
Other Renewables	0	0	0	18	27	32	32	41	54
Conservation	1	3	5	7	11	26	37	54	103
Total PRS Resources	***1***	***3***	***259***	***290***	***288***	***406***	***487***	***587***	***871***
Net Positions	**122**	**82**	**292**	**207**	**117**	**179**	**215**	**246**	**359**

Figure 8.30: Loads & Resources Energy Forecast with Lancaster in PRS (aMW)



strategy was not updated. Instead an alternative portfolio with Lancaster is compared to the PRS to illustrate its impacts. The Lancaster Generation Facility is a 245 MW gas-fired combined-cycle combustion turbine with an additional 30 MW of duct firing capability. It is a General Electric Frame 7FA plant that began commercial service in 2001. Lancaster is located in Rathdrum, Idaho, in the center of Avista's service territory. It is significantly lower in cost than a green field plant and would not expose the company to construction risk.

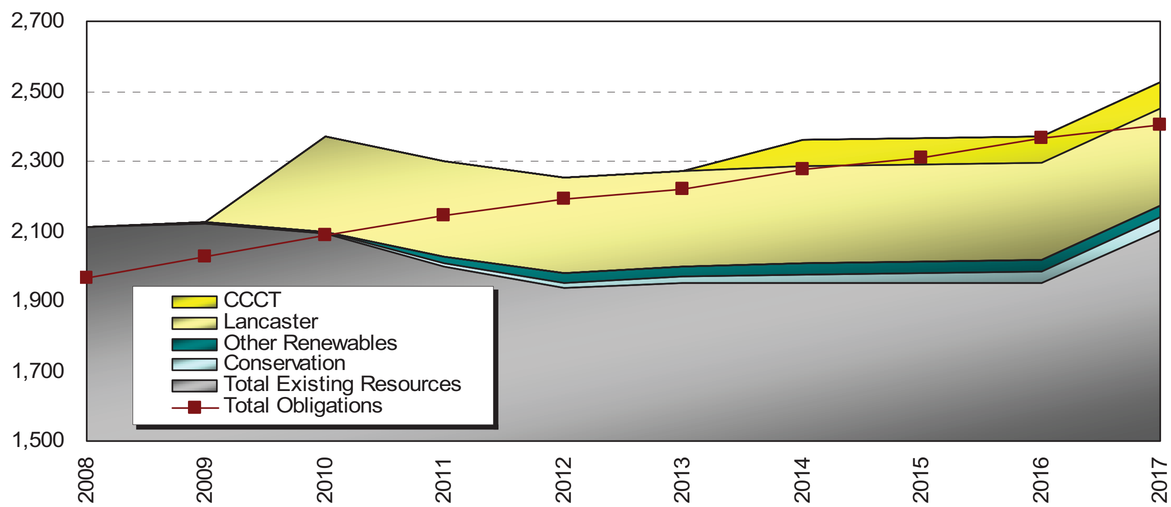
LANCASTER IMPACT ON L&R BALANCES

Lancaster substantially replaces the identified gas-fired CCCT included in the preferred resource strategy. Tables 8.13 and 8.14, and figures 8.30 and 8.31, present the PRS with Lancaster replacing a significant portion of

Table 8.14: Loads & Resource Capacity Forecast with PRS (MW)

	2008	2009	2010	2011	2012	2015	2017	2020	2027
Obligations									
Retail Load	1,703	1,763	1,815	1,868	1,909	2,019	2,103	2,214	2,492
Planning Margin	260	266	272	277	281	292	300	311	339
Total Obligations	***1,964***	***2,029***	***2,087***	***2,145***	***2,190***	***2,311***	***2,404***	***2,525***	***2,831***
Existing Resources									
Hydro	1,142	1,154	1,121	1,128	1,084	1,098	1,098	1,070	1,070
Net Contracts	172	172	173	73	58	58	208	128	128
Coal	230	230	230	230	230	230	230	230	230
Biomass	50	50	50	50	50	50	50	50	50
Gas Dispatch	308	308	308	308	308	308	308	308	308
Gas Peaking Units	211	211	211	211	211	211	211	211	211
Total Existing Resources	***2,111***	***2,123***	***2,092***	***1,999***	***1,939***	***1,954***	***2,104***	***1,996***	***1,996***
Net Positions	**148**	**94**	**5**	**-146**	**-251**	**-357**	**-300**	**-530**	**-835**
PRS Resources									
Lancaster	0	0	275	275	275	275	275	275	0
CCCT	0	0	0	0	0	75	75	156	677
Coal	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0
Other Renewables	0	0	0	20	29	34	34	44	59
Conservation	1	3	5	7	11	26	37	54	103
Total PRS Resources	***1***	***3***	***280***	***302***	***316***	***410***	***421***	***530***	***839***
Net Positions	**149**	**97**	**285**	**156**	**65**	**53**	**122**	**0**	**4**
Planning Margins (%)	**24.0**	**20.6**	**30.6**	**23.2**	**18.1**	**17.1**	**20.1**	**14.1**	**13.8**

Figure 8.31: Loads & Resources Capacity Forecast with Lancaster in PRS (MW)



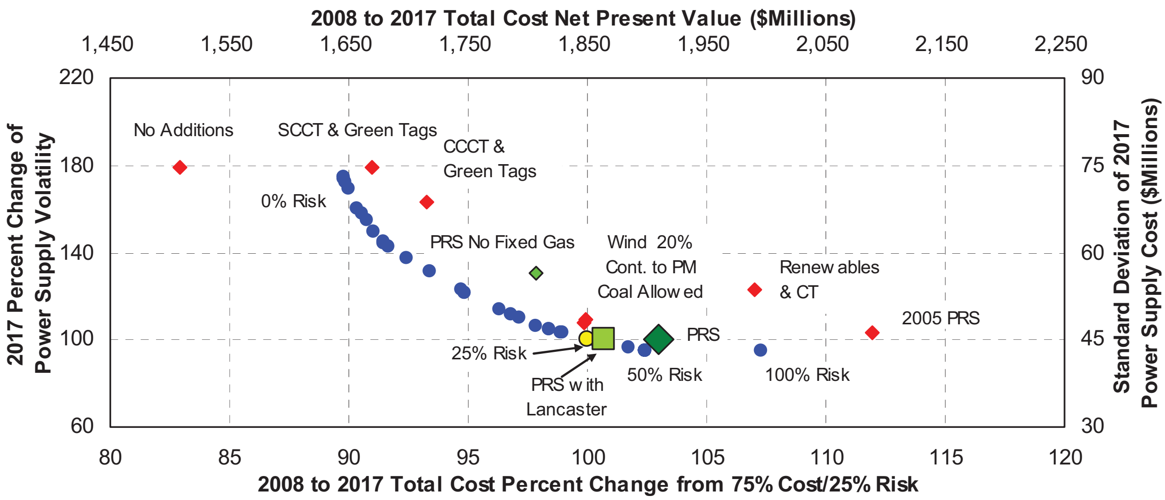
the CCCT needs identified for the PRS. The addition of Lancaster pushes the company's resource need out to 2014.

LANCASTER IMPACT ON PORTFOLIO COSTS AND RISK

The Lancaster plant costs less than an equivalent new gas-fired CCCT while providing the same benefits.

Another way to compare the addition of Lancaster to the Preferred Resource Strategy is to plot a new PRS with Lancaster's costs on the Efficient Frontier. Figure 8.32 provides an updated efficient frontier where Lancaster replaces a majority of the PRS gas-fired acquisition during the first decade of the plan. Including Lancaster reduces costs approximately 6 percent under the original

Figure 8.32: Efficient Frontier with Lancaster Plant



PRS for the same amount of risk. Savings are created by acquiring a more cost-effective plant and an adjustment to new resource additions.

9. ACTION ITEMS

The Integrated Resource Plan (IRP) is an ongoing and iterative process attempting to balance the need for regular publications with pursuing the best 20-year forecast possible. The set biennial publication date means that there is always room for improvements or additional research. This section provides an overview of the progress that has been made regarding the 2005 IRP Action Plan. The 2007 IRP Action Plan provides details about the issues and improvements that were developed or raised during this planning cycle and those that need to be deferred to the 2009 IRP.

SUMMARY OF THE 2005 ACTION PLAN

The 2005 IRP includes Action Items in four separate areas: renewable energy and emissions, modeling enhancements, transmission modeling and research, and conservation.

RENEWABLE ENERGY AND EMISSIONS

- Commission a study to assess wind potential within Avista's service territory.
- Continue to monitor emissions legislation and its potential effects on markets and the company.
- Research clean coal technology and carbon sequestration.
- Assess biomass potential within and outside of Avista's service territory.

Avista hired a meteorological consultant who completed map and aerial studies of wind potential within the company's service territory. Several promising sites were located that warrant further consideration and assessment. The next steps involve contacting landowners to assess their interest in allowing the installation of anemometers to test wind speeds and shapes for at least a one-year period. This research will be ongoing and will be reported in the 2009 IRP.

Avista has actively monitored state and federal emissions legislation which has resulted in the company taking several steps forward in this area. Most notably, an entire section of this IRP has been dedicated to emissions issues, greenhouse gas emissions cost estimates have been included in the Base Case, and an Avista Climate Change Council has been convened to bring all of the functional areas of the company together address climate change issues.

Wind Turbines Generating Electricity

A variety of different coal technologies have been researched for this IRP through the joint request for information with Idaho Power. The research for this process has resulted in more up-to-date capital costs for sub-critical, supercritical and ultra-critical pulverized coal, circulating fluidized bed and integrated gas combined cycle technologies. These have been included in the Technical Advisory Committee (TAC) presentations available at the company's IRP Website. Presentations on clean coal technologies and carbon capture and sequestration are also included in the TAC presentation. The steep increases in capital costs, recent Washington state legislation and changes in Avista management directives have moved non-sequestered coal completely out of the plan. However, we will continue to research coal technologies to help us better understand resources throughout the Western Interconnect and in case new, clean coal technologies become cost effective in the future.

Some initial assessments of biomass potential within and outside of Avista's service territory have been researched. Recent studies have indicated total amounts of biomass availability by county in Washington, but further work needs to be done to determine the amount of biomass that is economically recoverable and feasible to obtain. One benefit of the recent RPS legislation should be more research into renewable technologies, including biomass. This action item will need to be carried forward to the 2009 IRP.

MODELING ENHANCEMENTS

- Evaluate the 70-year water record for inclusion in 2007 IRP studies.
- Add more functionality to the Avista Linear Programming Model (e.g., direct consideration of cash flow and rate impacts versus after-the-fact reviews).

The 70-year water record has been reviewed and implemented in the modeling for this IRP. The Avista Linear Programming Model or PRiSM has been enhanced to handle 300 iterations, cash flow, power supply rate impacts, and improved the overall functionality and reporting abilities.

TRANSMISSION MODELING AND RESEARCH

- Work to maintain/retain existing transmission rights on the company's transmission system, under applicable FERC policies, for transmission service to bundled retail native load.
- Continue involvement in BPA transmission practice processes and rate proceedings to minimize costs of integrating existing resources outside of the Company's service area.
- Continue participation in regional and sub-regional efforts to establish new regional transmission structures (Grid West and TIG) to facilitate long-term expansion of the regional transmission system.
- Evaluate costs to integrate new resources across Avista's service territory and from regions outside of the Northwest.

Chapter 4 contains details about Avista transmission modeling and research. These Action Items will continue to be important in the 2009 IRP.

CONSERVATION

- Review the potential for cost-effective load shifting programs using hourly market prices.
- Complete the conservation control project currently underway as part of the Northwest Energy Efficiency Initiative for future evaluation as a potential conservation resource.

Several new programs and measures are being developed in addition to enhancements to the company's existing programs. Load management pilot programs are being developed for implementation beginning in 2007 in Moscow and Sandpoint, Idaho. Large customer interruption and distributed generation projects are also being researched. Nine potential transmission and distribution efficiency measures were identified and studied. Three of these projects are currently at the work-in-progress phase of development.

2007 IRP ACTION PLAN

The company's 2007 Preferred Resource Strategy provides direction and guidance for resource acquisitions. The 2007 IRP action plan lists the activities that will be carried out for inclusion in the 2009 IRP. Progress will be monitored and reported in Avista's 2009 Integrated Resource Plan. Each item in the action plan was developed using input from Commission Staff, the company's management team and the Technical Advisory Committee.

RENEWABLE ENERGY

- Continue studying wind potential in the company's service territory, possibly including the placement of anemometers at the most promising wind sites.
- Commission a study of Montana wind resources that are strategically located near existing company transmission assets.
- Learn more about non-wind renewable resources to satisfy renewable portfolio standard requirements and decrease the company's carbon footprint.

DEMAND SIDE MANAGEMENT

- Update processes and protocols for integrating energy efficiency programs into the IRP to improve and streamline the process.
- Study and quantify transmission and distribution system efficiency concepts.
- Determine the potential impacts and costs of load management options currently being reviewed as part of the Heritage Project.
- Develop and quantify the long-term impacts of the newly signed contractual relationship with the Northwest Sustainable Energy for Economic Development organization.

EMISSIONS

- Continue to evaluate the implications of new rules and regulations affecting power plant operations, most notably greenhouse gases.
- Continue to evaluate the merits of various carbon quantification methods and emissions markets.

MODELING AND FORECASTING ENHANCEMENTS

- Study the potential for fixing natural gas prices through financial instruments, coal gasification, investments in gas fields or other means.
- Continue studying the efficient frontier modeling approach to identify more and better uses for its information.
- Further enhance and refine the PRiSM LP model.
- Continue to study the impact of climate on the load forecast.
- Monitor the following conditions relevant to the load forecast: large commercial load additions, Shoshone county mining developments and the market penetration of electric cars.

TRANSMISSION PLANNING

- Work to maintain/retain existing transmission rights on the company's transmission system, under applicable FERC policies, for transmission service to bundled retail native load.
- Continue involvement in BPA transmission practice processes and rate proceedings to

minimize costs of integrating existing resources outside of the Company's service area.

- Continue participation in regional and sub-regional efforts to establish new regional transmission structures (ColumbiaGrid and other forums) to facilitate long-term expansion of the regional transmission system.
- Evaluate costs to integrate new resources across Avista's service territory and from regions outside of the Northwest.

PRODUCTION CREDITS

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2007 Avista Integrated Resource Plan
Supplemental Material

Section 1:
Technical Advisory Committee Meeting Presentation Materials

Section 2:
Portfolio Results Comparison for the Climate Stewardship Act Future, Volatile Gas Future, and the No Carbon Legislation Future

Section 3:
Demand Side Management Measures Cost Effectiveness Summary

Section 4:
Resource Integration Costs (Transmission Estimates)

Avista Utilities 2007 Integrated Resource Plan

Technical Advisory Committee Meeting No. 1 Agenda
February 24, 2006

	Topic	Time	Staff
1.	Introductions	10:00	Barcus
2.	New and Potential Rules and Laws For Integrated Resource Planning	10:05	Lyons
3.	Work Plan Discussion	10:20	Gall
4.	Transmission Planning	10:45	Folsom
5.	2005 IRP and TAC Comments	11:15	Lyons
6.	Lunch	11:45	
7.	2007 IRP Topic Discussions • Resource Planning • Conservation • Analytical Process • Capacity Planning • Other	12:30	Kalich
8.	Adjourn	2:00	

ENERGY AT WORK

AVISTA Utilities

Integrated Resource Planning

2007 Integrated Resource Plan
First Technical Advisory Committee Meeting
February 24, 2006

John Lyons

Integrated Resource Planning

- Investor owned utilities are required by Washington and Idaho state law to submit a comprehensive integrated resource plan (IRP) every two years.
- The plan includes a long-term forecast for a variety of topics including:
  - Loads and resources
  - Conservation
  - Transmission planning
  - Potential resource evaluations
  - Base and scenario driven price forecasts
  - Preferred Resource Strategy
  - Emissions and Environmental Analyses
  - Special studies

New Developments for the 2007 IRP

- Washington House Bill 2351 filed December 2005
  - Encourage the construction of renewable generation through a renewable portfolio standard (RPS)
  - Require investor and community owned utilities to file IRPs
  - IRP "must include demand forecasts, assessment of technically feasible improvements, assessment of technically feasible generating technologies, resource evaluation, and specific actions to be taken by the utility …the plan must also include a progress report that relates the new plan to the previous plan."
- Updated IRP Rules: "Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources." (WAC 480-100-238 (4))

More Participation for the 2007 IRP

- Increased the size and scope of the invitation list
- Sought feedback on 2005 IRP TAC process
- NPCC – Specific invitations made to technical staff with focus on topic areas
- Environmental Community – Invitations to NWEC/NRDC
- Peer Utilities – personal invitations made to IRP technical staff from NW utilities
- Academic Community – invitations to WSU, OSU and Gonzaga

ENERGY AT WORK

AVISTA Utilities

2007 IRP Work Plan Discussion

2007 Integrated Resource Plan
First Technical Advisory Committee Meeting
February 24, 2006

James Gall

Work Plan Background

- The Work Plan is provided in response to WAC 480-100-238 in the state of Washington
- Outlines the process that we will take to develop the 2007 Integrated Resource Plan
- Will use a process similar to the previous two plans
- Improvements to the 2007 IRP include more detailed site-specific resource assumptions, wind integration costs, sustained peaking capacity, a cost of service study, and a detailed analysis of conservation programs

Work Plan Details

Proposed TAC meetings

- February 24, 2006
- September 2006
- December 2006
- February 2007
- April 2007
- May 2007
- July 2007 – tentative IRP draft review

2007 IRP Tasks

- Resource options
- Update AURORA^{XMP} database
- Develop Avista load forecast
- Cost of service study
- Develop deterministic base case
- Simulate market scenarios
- Create data sets and statistics for risk studies
- Conservation study
- Simulate base case risk study
- Simulate risk study “futures”
- Enhance PRS LP model
- Develop efficient frontier for PRS with LP Model

2007 IRP Report Tasks

- Prepare IRP report and appendix outline
- Prepare text drafts
- Prepare charts and tables
- Internal draft release and review
- External draft release and review
- Final editing and printing
- Final report distribution and submission
- Technical Advisory Committee survey and comments

Transmission Planning

2007 Integrated Resource Plan
First Technical Advisory Committee Meeting
February 24, 2006

Bruce Folsom

FERC's Standards of Conduct and IRPs

- FERC revised its Standards of Conduct for Transmission Providers Rule – effective on September 22, 2004
- Orders 2004, *et.al*., require a separation of transmission system operation employees from merchant employees to prevent the energy marketing branch of a company from having more information than publicly available. "The purpose of the prohibition is to prevent transmission providers from unduly favoring their affiliates with transmission information that is not disclosed to non-affiliates thereby disadvantaging the non-affiliates."
- Shared employees, who operate in both realms cannot be a conduit to pass transmission information between the transmission and merchant groups
- This presents unique issues for utilities that house integrated resource planning in its merchant function

FERC Response to Planning Constraints

In a November 2005 letter to the Oregon PUC, FERC acknowledged that:

– "… integrated resource planning is important in fulfilling the mandate of Section 1233 of the Energy Policy Act of 2005 to encourage the planning and expansion of transmission facilities."
– "… resource planning can be accomplished, in many instances, within the guidelines established by Order No. 2004."
– Case-by-case waivers for the standards can be applied for specific situations
– "I feel confident that we can find creative ways in which to facilitate integrated resource planning while maintaining allegiance to the non-discrimination goals of the Standards of Conduct."

FERC and Transmission Planning

- Meetings between transmission employees and merchant employees that may address proprietary transmission information must be posted to OASIS (Open Access Same-time Information System). Therefore all TAC meetings involving transmission personnel or inviting transmission personnel will be posted to OASIS.
- Meeting notes will be taken
- Questions about transmission studies conducted by the Transmission Department can be asked provided that answers will not consist of prohibited information
- Transmission studies and any supporting data must be posted to OASIS on a "same-time" basis when provided to merchant employees.
- Responses and results of transmission studies will be posted to OASIS at http://www.oatioasis.com/avat/index.html

Current IRP Transmission Planning

- Meet with Transmission Planners to identify transmission system opportunities
- Consider new transmission lines and upgrades
  – Specifics of opportunities may need to be “generic” to prevent transfer of information (i.e., from Avista Merchant)
- Discuss potential locations of new resources and the transmission upgrades necessary for integration

ENERGY AT WORK

AVISTA Utilities

2005 IRP and TAC Comments

2007 Integrated Resource Plan
First Technical Advisory Committee Meeting
February 24, 2006

John Lyons

2005 TAC Survey

Avg. Response	Scale	Questions
2.9	0 – 7	Have many TAC meetings did you attend?
7.9	1 – 10	Rank the number and length of TAC meetings.
8.4	1 – 10	Rank of content of the meetings.
8.2	1 – 10	Rank of overall TAC process.

2005 TAC - Areas Performed Well

- Content of the material
- Description of modeling approaches and results
- Reporting a complex subject in summary fashion
- Thorough analysis
- Meetings were well planned and conducted
- Presentations were well done
- Policy issue discussions
- Financial impact of planning and discussion of financial-economic environment
- Encouraging interaction/involvement
- Information sharing

2005 TAC – Areas for Improvement

- Increase attendance and TAC member diversity
- More details on the mathematical methodologies used
- More discussion on transmission constraints and FERC policy
- Focus on DSM earlier in the process
- Present Avista-specific plans earlier in the process
- Improve opportunities for participation by phone
- Do not assume qualifications of the TAC members
- Continue to improve modeling
- Improve communication of expectations and results
- Provide information prior to the meetings
- Leave more time for comments, refinement, and additional analysis at the end of the process

2005 TAC – Possible Meeting Sites

- Spokane – at Avista headquarters
- Conference call – possibly with West, East and Boise locations
- Olympia
- Boise
- Seattle
- PNNL
- Large customer sites
- At generation projects – such as CS2 or a potential site
- Pullman

Topics for the 2007 IRP

- Most surveys had no additional topics for consideration
- Would like to see additional work on the integration of DSM and energy efficiency
- Provide a more robust consideration of nuclear power
- Include more customer based cogeneration

2007 IRP Topic Brainstorm

2007 Integrated Resource Plan
First Technical Advisory Committee Meeting
February 24, 2006

Clint Kalich

Resource Planning

- Supply-Side Resource Assumptions
  - Generic (e.g., NPCC) vs. site-specific data
  - Pros and cons
- Modeling Emissions
- WA RPS Initiative

Conservation

- Should 2007 IRP diverge from 2005 methodology
- CVR load control study update
- Transmission efficiency upgrades
  - How do we get the data?
  - 10% market adder was used for the 2005 IRP for all conservation
    - i.e., traditional DSM, plant upgrades

Capacity Planning

- Sustained peaking capacity analysis
  - Can we reach consensus in 2007 IRP timeframe
  - Wind vs. other resources
- Wind integration studies
  - 2002 work and 2006 consultant study findings
- Wind contribution to peak demand
  - Does wind add to system peaking capability?

Analytical Process

- Monte Carlo Analyses
  - 2005 IRP varied gas, load, hydro, and wind
  - More/Less for 2007
- Hydro Issues
  - 70-year hydro study is now available
  - Breaking out the Northwest is in progress
- Scenarios and futures
  - What would the TAC like to see for 2007?

Other Areas

- Peak capacity credit method for cost of service

Avista Utilities 2007 Integrated Resource Plan
Technical Advisory Committee Meeting No. 2 Agenda
August 31 & September 1, 2006

8/31/06

• Introductions	9:30	Barcus
• Review of TAC-1 Meeting	9:35	Lyons
- Review 2005 Action Plan		
• IRP Modeling Overview	10:00	
- Emissions		Lyons
- Fuel Price Forecasts		Gall
- Other Modeling Assumptions		Gall
- Preliminary Transmission Costs & Paths		Heath
- Resource Options & Cost Assumptions		Lyons
- Futures and Scenarios		Lyons
• Lunch – Presentation on 2006 Renewables RFP	12:00	Silkworth
• IRP Modeling Overview, Continued	1:00	Lyons
• Future Resource Requirements (L&R)	2:00	Heath
• Review of Futures & Scenarios Market Results	2:30	Gall
• Preview of Preliminary Preferred Resource Strategy	4:00	Kalich
• Adjourn	4:30	

9/01/06

• Review of First Day/Discussion/TAC Input	8:30	Lyons
• Preliminary PRS Discussion	10:00	Gall/Kalich
- Portfolio Selection Criteria		
- Futures & Scenarios		
- PRS Selection Model		
- Results		
• Lunch – Alternative Energy Future Discussion	12:00	Lyons
• Preliminary PRS Discussion, Continued	1:00	Gall/Kalich
• Adjourn	2:30	

We answer to you.

Review of First TAC Meeting & 2005 IRP Action Plan Review

2007 Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

John Lyons

We answer to you.

Review of First TAC Meeting

The First Technical Advisory Committee Meeting was on February 24, 2006:

- New and potential rules and laws for integrated resource planning
- Work plan discussion – what will be presented to the TAC
- Transmission planning – FERC guidelines
- Reviewed comments on the 2005 IRP and TAC
- Started 2007 IRP topic discussions including resource planning, conservation, analytical process, capacity planning, and ideas from TAC members

We answer to you.

2005 IRP Action Plan

The Action Plan for 2005 includes activities planned to support the PRS from the 2005 IRP, enhance the process, and research areas of interest not included in the 2005 IRP

The 2005 Action Plan covered four major areas:

1. Renewable Energy and Emissions
2. Modeling Enhancements
3. Transmission Modeling and Research
4. Conservation

We answer to you.

Renewable Energy and Emissions

1. Commission a study to assess wind potential in Avista's service territory
   - Wind map survey of our service territory has been completed
   - An aerial survey for wind flagging has been completed on the more promising sites
   - Several promising areas have been located and are being researched

2. Continue to monitor emissions legislation and its potential effects on markets and the Company
   - Ongoing review at state, regional, and national levels
   - Have formed a committee on climate change

We answer to you.

Renewable Energy and Emissions

3. Research clean coal technology and carbon sequestration
   - There will be a lunch presentation at the next TAC meeting

4. Assess biomass potential within and outside Avista's service territory

5. Continue to study the availability of various renewable energy technologies, including local sites
   - RFP for renewable energy – lunch presentation today
   - Open to reviewing any projects that are brought to us

We answer to you.

Modeling Enhancements

1. Evaluate 70-year water record for inclusion in 2007 IRP studies
   - This has been included – will provide more details in the modeling presentation later today

2. Add more functionality to the Avista Linear Programming Model
   - Direct consideration of cash flow and rate impacts versus after-the-fact reviews
   - We will be working on this for the final PRS

We answer to you.

Transmission Modeling and Research

1. Work to maintain/retain existing transmission rights on the Company's transmission system
2. Continue involvement in BPA transmission business practice processes and rate proceedings
3. Continue participation in regional and sub-regional efforts to establish new regional transmission structures
   - Avista is participating in ColumbiaGrid
4. Evaluate costs to integrate new resources across Avista's service territory and from regions outside of the Northwest
   - Internal cost studies are being done by the transmission group and we are reviewing outside studies as they become available

We answer to you.

Conservation

1. Review the potential for cost-effective load shifting programs using hourly market prices

2. Complete the conservation control project currently underway as part of the Northwest Energy Efficiency Initiative

We answer to you.

AVISTA Corp.

2006 Renewables Request for Proposals

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

Steve Silkworth

2006 Renewables RFP

- The 2005 Integrated Resource Plan indicates that Avista has a need for additional energy resources by 2016. These additional resources include:
  - 400 MW of wind power (approximately 135 average MW of energy)
  - 80 MW of other renewables (bio fuels, geothermal, etc)
  - 250 MW of coal
  - 52 MW of plant upgrades
  - 69 MW of conservation
- Avista's 2005 IRP Integrated Resource Plan will meet Washington State's proposed Renewable Portfolio Standard requirement.

We answer to you.

2005 IRP Implementation
2006 Renewables RFP

- A Request for Proposal for up to 35 average MW of renewable energy was issued to the public on January 4, 2006
- Bids were opened February 1, 2006
- 14 wind power bids received, 1190 MW of capability, 430 aMW energy
- Eight other bids received including: Geothermal power, land fill gas, wood biomass, wood gasification, small hydro, and bio-solids (waste wood and sludge) totaling 43 MW of capability and 40 aMW of energy

We answer to you.

2006 Renewables RFP

- Currently negotiating with one project to purchase up to 100 MW of wind power
  - Online date is projected to be December 2007
  - 50 MW with an option for an additional 50 MW
  - Power purchase agreement for 10 to 15 years with an option to own the project
  - Transmission availability has recently become an issue

We answer to you.

Wind Acquisition -- Next Steps

- Complete contract negotiations
- Solve transmission problems
- Management approval and enter into the agreement
- Continue researching potential wind development sites within Avista's service territory
- Continue the implementation of the 2005 IRP

We answer to you.

AVISTA

Alternative Energy Future

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
September 1, 2006

John Lyons

We answer to you.

Alternative Energy Future

Covering some of the more interesting alternative energy information that we have studied, but was not quite ready for resource planning for a variety of reasons, including:

- Cost effectiveness
- Scalability
- Commercial availability
- Unproven technology

We answer to you.

AVISTA

Energy Storage Technologies

- Vanadium batteries – basically a large battery system that is charged in off-peak hours and discharged to shave peak load
  - Advantages
    - Less toxic and more efficient that traditional battery technologies
    - Useful in special circumstances to prevent or at least delay additional transmission or generation acquisitions
  - Disadvantages
    - High cost – Capital cost of $5,200 per kW
    - Size limitations – 25 kW up to 10 MW for several hours

Energy Storage Technologies cont.

- Other storage technologies exist and are in development, particularly for wind projects
  - Compressed air energy storage – off peak energy is used to compress air in a sealed chamber (cavern, mine, well, etc) and then released during peak hours with some natural gas and burned in a gas turbine
    - Two major operating sites: 110 MW plant in McIntosh, Alabama and a 230 MW facility in Huntdorf, Germany
    - Manufacturers claim to be able to construct facilities from 5 MW to 350 MW
  - Advantages – overcome some of the variability and capability problems with wind
  - Disadvantages – losses of up to 80% when removing compressed air and cost of constructing facility

We answer to you.

Wave or Tidal Power

- Conversion of the inherent energy in waves or tides into electricity from a variety of different methods
- Completed and proposed sites are in the North Sea, New Jersey, Hawaii, Scotland, England, Western Australia, and off the coast of Washington
- Advantages:
  - No fuel costs
  - No emissions impact
- Disadvantages:
  - Site issues concerning sea life
  - Unproven technology, long-term reliability concerns
- Costs estimates range from $400 to $1,700 per kW

We answer to you.

Alternative Wind Technologies

There are several wind issues and technologies we are studying

- Marine based turbines – larger sizes, GE developing 5 MW plant
- New blade designs – shapes, sizes, and materials
  - Owens Corning E-Glass – 6% longer blades, 12% more power, and 20% less cost available in late 2006
- Flying wind turbines – placed into the jet stream up to 30,000 feet
- These issues will probably not result in a radical change in the wind industry, but will most likely improve efficiencies

We answer to you.

AVISTA

Biomass Technologies

- Wood waste, landfill gas, and manure digesters are already included in the IRP, but wanted to cover some of the technology that is being developed
- Includes any crops that are converted into liquid fuels, such as biodiesel and ethanol
- Advantages:
  - Local economic benefits because of the distributed nature of production
  - Lower dependence on outside sources
- Disadvantages:
  - High costs due to the state of the technology and size of the industry
  - Substantial federal subsidies
  - Issues with removing crops from the food supply, especially with corn
  - Less energy dense than petroleum derived fuels – net energy benefits

We answer to you.

Solar Energy

Photovoltaic resources are included in the IRP:

- Problems with using PV on a large scale due to high capital costs in excess of $7,000 per kW and capacity constraints
- Current manufacturing technologies have an energy payback of about 3 years, new technologies are projected to reduce this to 2 years
- PV has averaged 35% growth over the past 35 years, but still only provides about 0.1% of worldwide electric supply
- Benefits are free fuel and reductions in CO_2 – 1 kW of solar energy reduces CO_2 by 2,600 pounds per year
- New manufacturing technologies are aimed at lowering capital costs and boosting production capacity – 430 MW of solar cell production being developed in Silicon Valley
- GE is building a 150-acre solar project in Portugal
  - 52,000 PV cells for 11 MW at a price of $75 million
  - Portugal has a law requiring utilities to pay 0.31 Euros per kWh or about $0.40 per kWh in the US

We answer to you.

Other Forms of Solar Energy

Solar Tower

- The tower works by concentrating heating the air which will move up the chimney at speeds of up to 35 miles per hour where wind turbines are stationed
- Originally planned for 200 MW on a 25,000 acre site with a 3,280 feet tall at a price of about $1 billion
- Recently scaled back to 50 MW with a 1,600 foot tall tower for $250 million ($5,000 per kW)
- A successful 50 kW prototype was constructed in Spain in 1982 and it operated until 1989

Solar Trough

- Uses parabolic mirrors to concentrate the sun's energy to heat tubes of mineral oil to 250 to 550 degrees, which is run through a heat exchanger and then a turbine
- APS has a 1 MW plant in Arizona completed this year for $6 million

We answer to you.

Modeling Overview: Emissions

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

John Lyons

We answer to you.

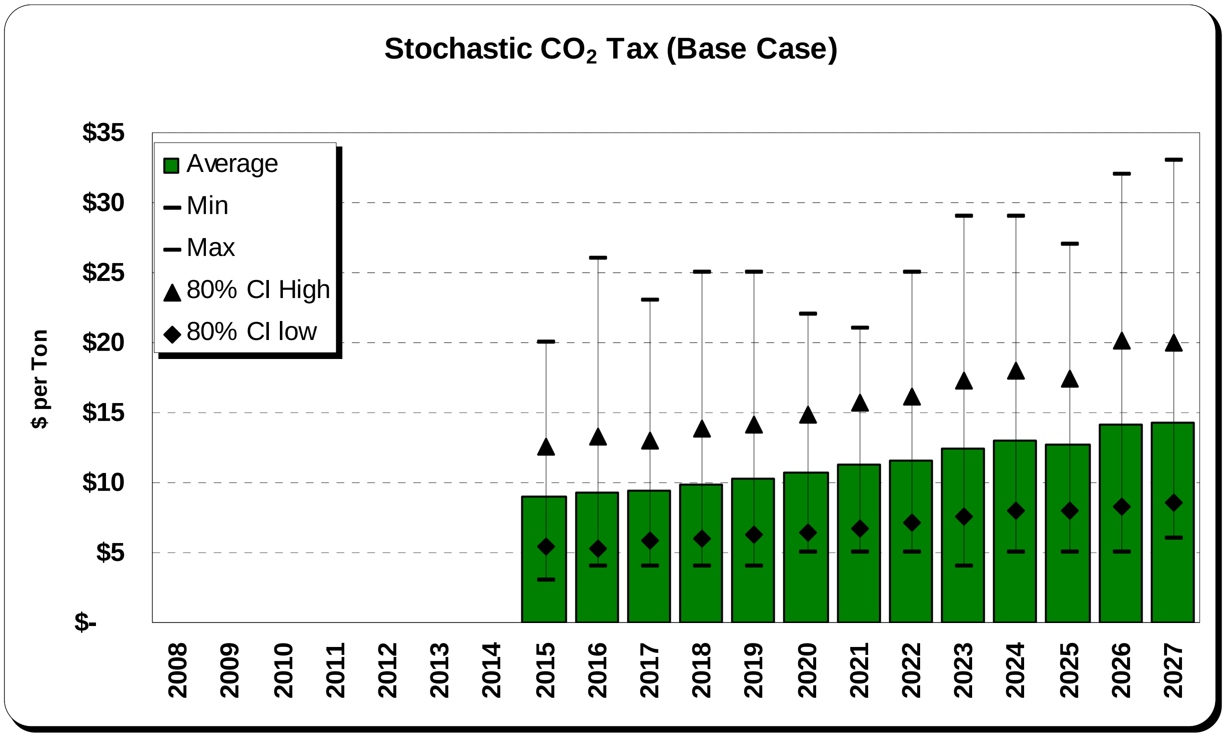
AVISTA

Emissions in the IRP

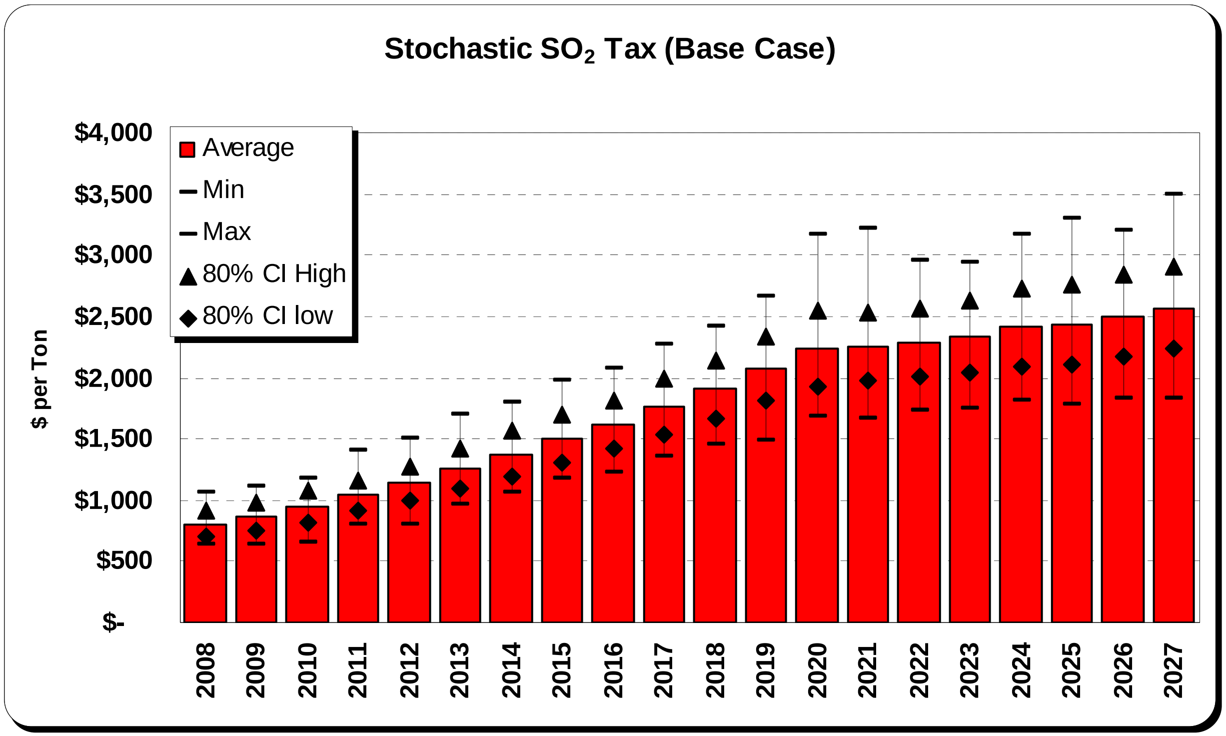
Several emissions costs are being included in the Base Case for the 2007 IRP

- CO_2 – carbon dioxide, the primary greenhouse gas
- SO2 – sulfur dioxide, causes acid rain, the Clean Air Act of 1990 capped at 8.9 million tons per year starting in 2008
- NOx – nitrogen oxide, causes acid rain, the Clean Air Act of 1990 capped emissions at 2.0 million tons per year starting in 2008
- Hg – mercury; highly toxic; planned regulation by the federal government under a cap and trade program but many states are opting out of that program

Base Case – Greenhouse Gas Costs

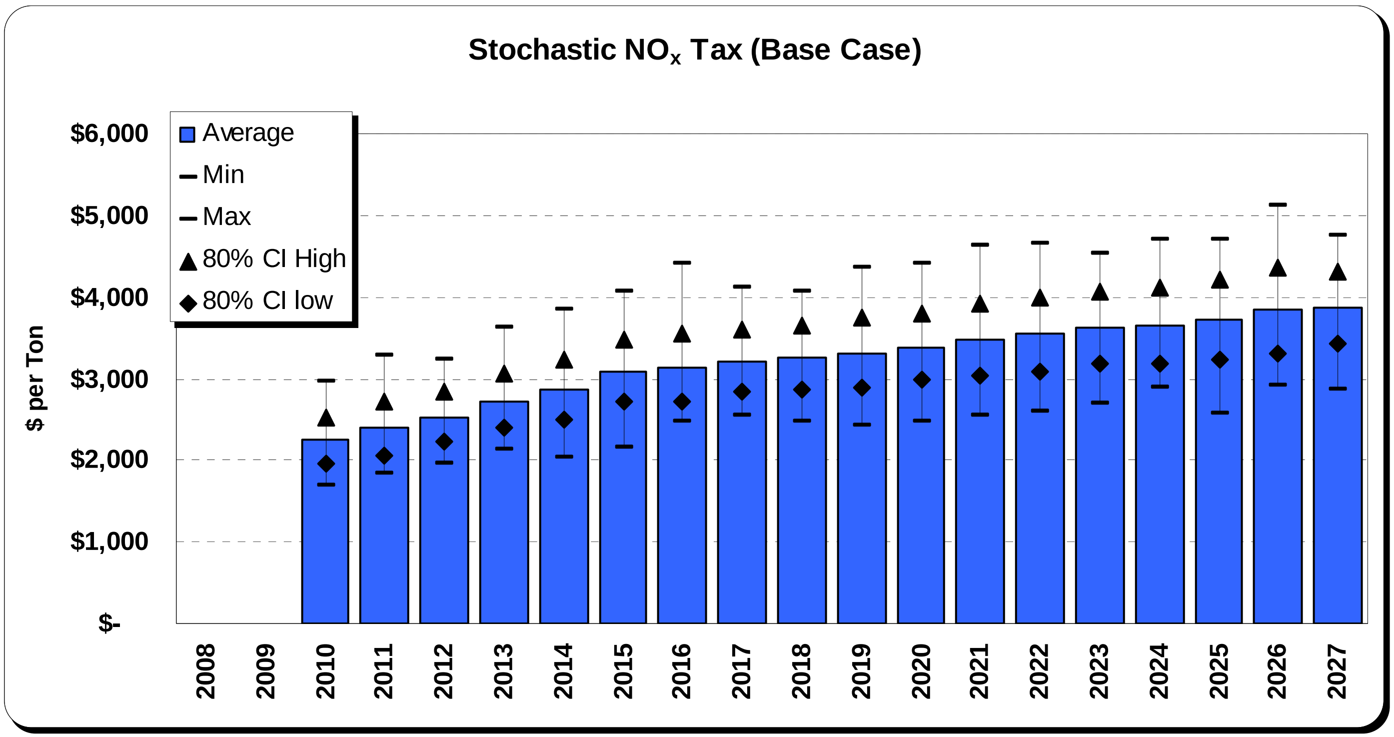


Base Case - SO_2 Emissions Costs



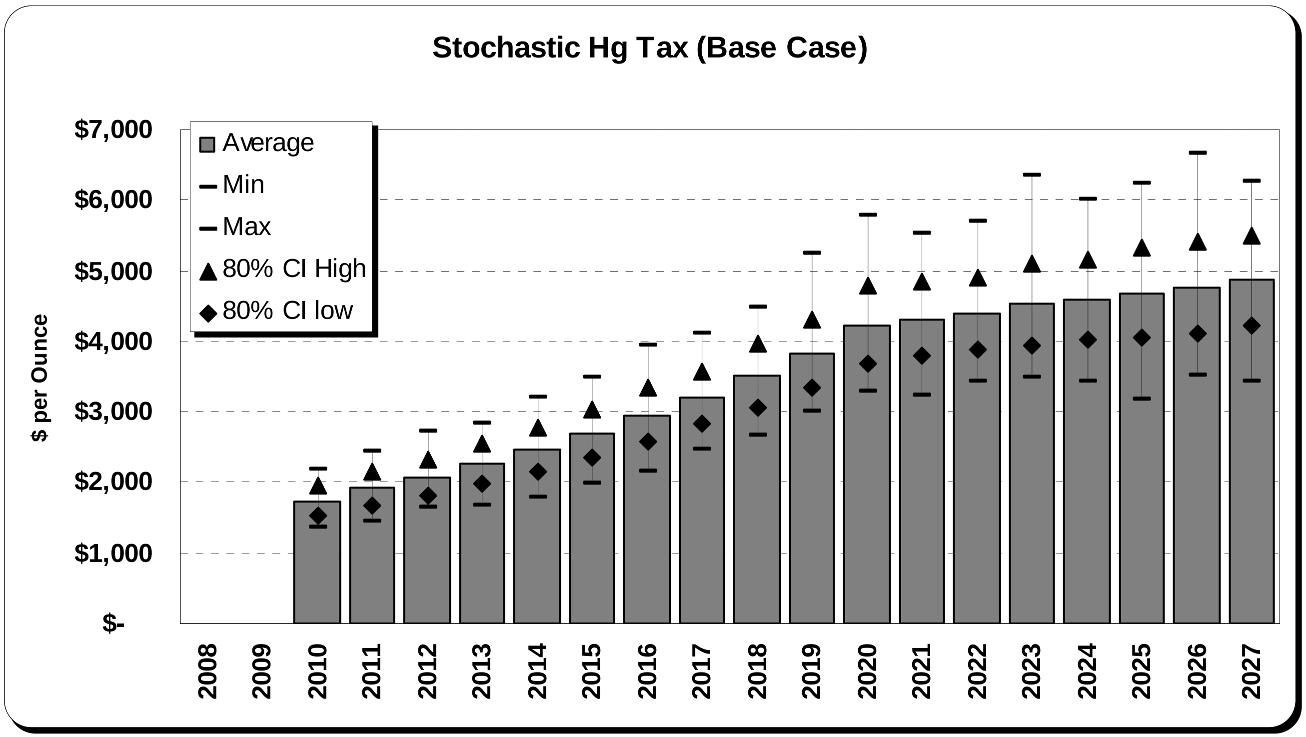
We answer to you.

Base Case – Stochastic NO_x Costs



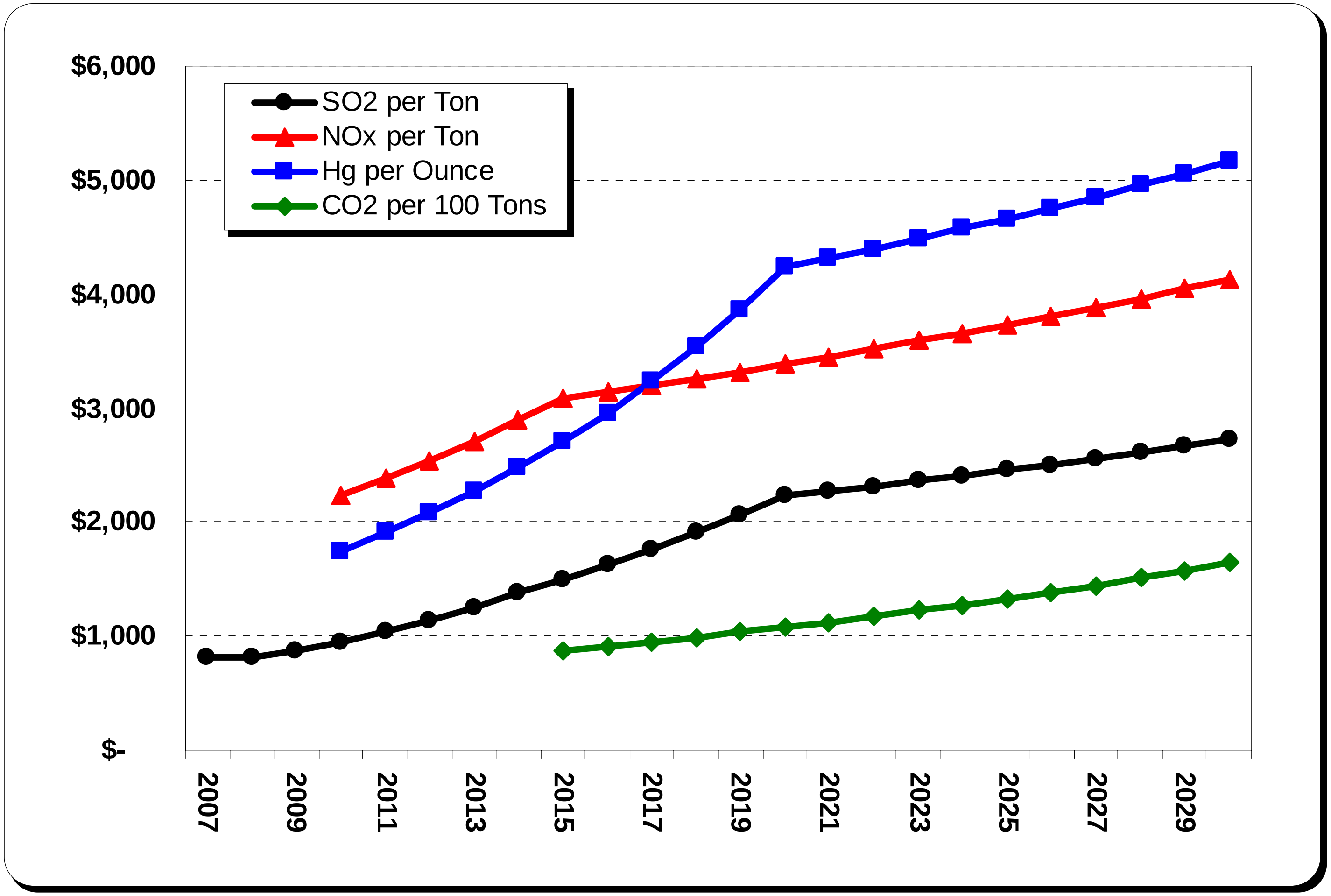
We answer to you.

Base Case – Stochastic Hg Tax



We answer to you.
AVISTA

Emission Costs - Nominal Dollars



We answer to you.

IRP Modeling Overview: Resource Options and Cost Assumptions

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

John Lyons

We answer to you.

Supply Side Options Included in Model

- Natural Gas Combined Cycle (CCCT)
- Natural Gas-Fired Simple Cycle (SCCT)
- Wind Turbine
- Coal Pulverized Subcritical
- Coal – Supercritical
- Coal – Ultracritical
- Coal – IGCC
- Coal – IGCC with Sequestration
- Geothermal
- Biomass
- Alberta Oil Sands
- Nuclear
- Co-Generation, Conservation, and Photovoltaics will be included in the final PRS

Natural Gas Combined Cycle (CCCT)

- **Type:** 2x1 Natural Gas-Fired Combined Cycle F Class Gas Turbine with Duct Burner
- **Size (MW):** 610
- **Heat Rate (Btu/kWh):** 6,790 (duct burner at 9,300)
- **Fuel Source:** Pipeline natural gas
- **Availability:** 2008
- **Capacity Factor:** 90.1%
- **Capital Cost ($/kW):** $744
- **Variable O&M ($/MWh):** $3.23
- **Fixed O&M (kW/Year):** $9.16
- **Emissions (lbs/mmbtu):** SO_2= 0.0001 NO_X= 0.011 CO_2= 117 Hg =0.000001
- **Location Options:** Northwest
- **Production Tax Credit:** No

We answer to you.

Natural Gas Simple Cycle (SCCT) Option 1

- **Type:** Two General Electric LM6000 Aero-Derivatives
- **Size (MW):** 94
- **Heat Rate (Btu/kWh):** 9,000
- **Fuel Source:** Pipeline natural gas
- **Availability:** 2008
- **Capacity Factor:** 93.7%
- **Capital Cost ($/kW):** $790
- **Variable O&M ($/MWh):** $9.25
- **Fixed O&M (kW/Year):** $9.16
- **Emissions (lbs/mmbtu):** SO_2= 0.0001 NO_X= 0.011 CO_2= 117 Hg =0.000001
- **Location Options:** Northwest
- **Production Tax Credit:** No

We answer to you.

AVISTA

Natural Gas Single Cycle (SCCT) Option 2

- **Type:** Industrial Frame Unit, Generic NPCC Industrial Machine
- **Size (MW):** 94
- **Heat Rate (Btu/kWh):** 10,500
- **Fuel Source:** Pipeline natural gas
- **Availability:** 2008
- **Capacity Factor:** 93.7%
- **Capital Cost ($/kW):** $494
- **Variable O&M ($/MWh):** $4.63
- **Fixed O&M (kW/Year):** $6.87
- **Emissions (lbs/mmbtu):** SO_2= 0.0001 NO_X= 0.011 CO_2= 117 Hg= 0.000001
- **Location Options:** Northwest
- **Production Tax Credit:** No

Wind Turbine

- **Type:** Central station wind power project
- **Size (MW):** 100 (40 turbines)
- **Heat Rate (Btu/kWh):** N/A
- **Fuel Source:** Wind
- **Availability:** 2008
- **Capacity Factor:** 22.2% - 35.9%
- **Capital Cost ($/kW):** $1,600
- **Variable O&M ($/MWh):** $6.00 - $10.00 (includes royalties and integration)
- **Fixed O&M (kW/Year):** $17.50
- **Emissions (lbs/mmbtu):** N/A
- **Location Options:** Northwest and Montana
- **Production Tax Credit:** Yes through 2014

We answer to you.

Coal – Pulverized Subcritical

- **Type:** Pulverized Coal-Fired Subcritical Steam-Electric Plant
- **Potential Sizes (MW):** 180 – 1,000
- **Heat Rate (Btu/kWh):** 9,371
- **Fuel Source:** Western Low-Sulfur Sub-Bituminous Coal
- **Availability:** 2013
- **Capacity Factor:** 83.4%
- **Capital Cost ($/kW):** $1,758
- **Variable O&M ($/MWh):** $3.54
- **Fixed O&M (kW/Year):** $44.57
- **Emissions (lbs/mmbtu):** SO_2= 0.12 NO_X= 0.07 CO_2= 205 Hg= 0.00002
- **Location Options:** Montana and Wyoming
- **Production Tax Credit:** No

We answer to you.

Coal – Pulverized Supercritical

- **Type:** Pulverized Coal-Fired Supercritical Steam-Electric Plant
- **Size (MW):** 350 – 1,000
- **Heat Rate (Btu/kWh):** 8,955
- **Fuel Source:** Western Low-Sulfur Sub-Bituminous Coal
- **Availability:** 2013
- **Capacity Factor:** 83.4%
- **Capital Cost ($/kW):** $1,848
- **Variable O&M ($/MWh):** $3.50
- **Fixed O&M (kW/Year):** $45.50
- **Emissions (lbs/mmbtu):** SO_2= 0.12 NO_X= 0.07 CO_2= 205 Hg= 0.00002
- **Location Options:** Montana and Wyoming
- **Production Tax Credit:** No

We answer to you.

AVISTA

Coal – Pulverized Ultracritical

- **Type:** Pulverized Coal-Fired Ultracritical Steam-Electric Plant
- **Potential Sizes (MW):** 600 – 1,000
- **Heat Rate (Btu/kWh):** 8,825
- **Fuel Source:** Western Low-Sulfur Sub-Bituminous Coal
- **Availability:** 2013
- **Capacity Factor:** 83.4%
- **Capital Cost ($/kW):** $1,854
- **Variable O&M ($/MWh):** $3.53
- **Fixed O&M (kW/Year):** $46.55
- **Emissions (lbs/mmbtu):** SO_2= 0.12 NO_X= 0.07 CO_2= 205 Hg= 0.00002
- **Location Options:** Montana and Wyoming
- **Production Tax Credit:** No

We answer to you.

Coal – Circulating Fluidized Bed

- **Type:** Coal-Fired Circulating Fluidized Bed Steam-Electric Plant
- **Potential Sizes (MW):** 50 - 450
- **Heat Rate (Btu/kWh):** 9,300
- **Fuel Source:** Western Low-Sulfur Sub-Bituminous Coal
- **Availability:** 2013
- **Capacity Factor:** 83.4%
- **Capital Cost ($/kW):** $1,758 - $1,854
- **Variable O&M ($/MWh):** $3.50 - $5.57
- **Fixed O&M (kW/Year):** $44.57 - $48.43
- **Emissions (lbs/mmbtu):** SO_2= 0.55 NO_X= 0.18 CO_2= 205 Hg= 0.00033
- **Location Options:** Northwest, Montana, and Wyoming
- **Production Tax Credit:** No

Coal – IGCC

- **Type:** Coal-Fired Integrated Gasification Combined-Cycle with H-Class Turbine
- **Potential Sizes (MW):** 401 - 600
- **Heat Rate (Btu/kWh):** 8,131
- **Fuel Source:** Western Low-Sulfur Sub-Bituminous Coal
- **Availability:** 2013
- **Capacity Factor:** 82.3% - 85.3%
- **Capital Cost ($/kW):** $2,198 - $2,333
- **Variable O&M ($/MWh):** $2.83 - $2.91
- **Fixed O&M (kW/Year):** $53.57 - $54.98
- **Emissions (lbs/mmbtu):** SO_2= 0.03 NO_X= 0.15 CO_2= 205 Hg= 0.00000022
- **Location Options:** Northwest, Montana, and Wyoming
- **Production Tax Credit:** No

We answer to you.

Coal – IGCC with Sequestration

- **Type:** Coal-Fired Integrated Gasification Combined-Cycle with H-Class Turbine
- **Size (MW):** 490 gross and 401 net
- **Heat Rate (Btu/kWh):** 9,595
- **Fuel Source:** Western Low-Sulfur Sub-Bituminous Coal
- **Availability:** 2015
- **Capacity Factor:** 82.3% - 85.3%
- **Capital Cost ($/kW):** $2,814 - $2,987
- **Variable O&M ($/MWh):** $3.02 - $3.12
- **Fixed O&M (kW/Year):** $63.21 - $64.87
- **Emissions (lbs/mmbtu):** SO_2= 0.003 NO_X= .015 CO_2= 20.5 Hg= .000000022
- **Location Options:** Northwest, Montana, and Wyoming
- **Production Tax Credit:** No

Geothermal

- **Type:** Generic NPCC Unit
- **Size (MW):** 20
- **Heat Rate (Btu/kWh):** 15,000
- **Fuel Source:** Geological Steam
- **Availability:** 2008
- **Capacity Factor:** 92.3%
- **Capital Cost ($/kW):** $4,000
- **Variable O&M ($/MWh):** $2.00
- **Fixed O&M (kW/Year):** $70.00
- **Emissions (lbs/mmbtu):** N/A
- **Location Options:** Southern Idaho
- **Production Tax Credit:** Yes through 2014

We answer to you.

Biomass

- **Type:** Wood Residue, Landfill, and Manure (Open Loop)
- **Size (MW):** 1 - 25
- **Heat Rate (Btu/kWh):** 12,000
- **Fuel Source:** Wood, Refuse, and Manure
- **Availability:** 2008
- **Capacity Factor:** 92.3%
- **Capital Cost ($/kW):** $3,500
- **Variable O&M ($/MWh):** $16.00
- **Fixed O&M (kW/Year):** $35.00
- **Emissions (lbs/mmbtu):** SO_2= N/A NO_X= N/A CO_2= 720 – 1,116 Hg= N/A
- **Location Options:** Northwest
- **Production Tax Credit:** Yes through 2014

We answer to you.

Alberta Oil Sands

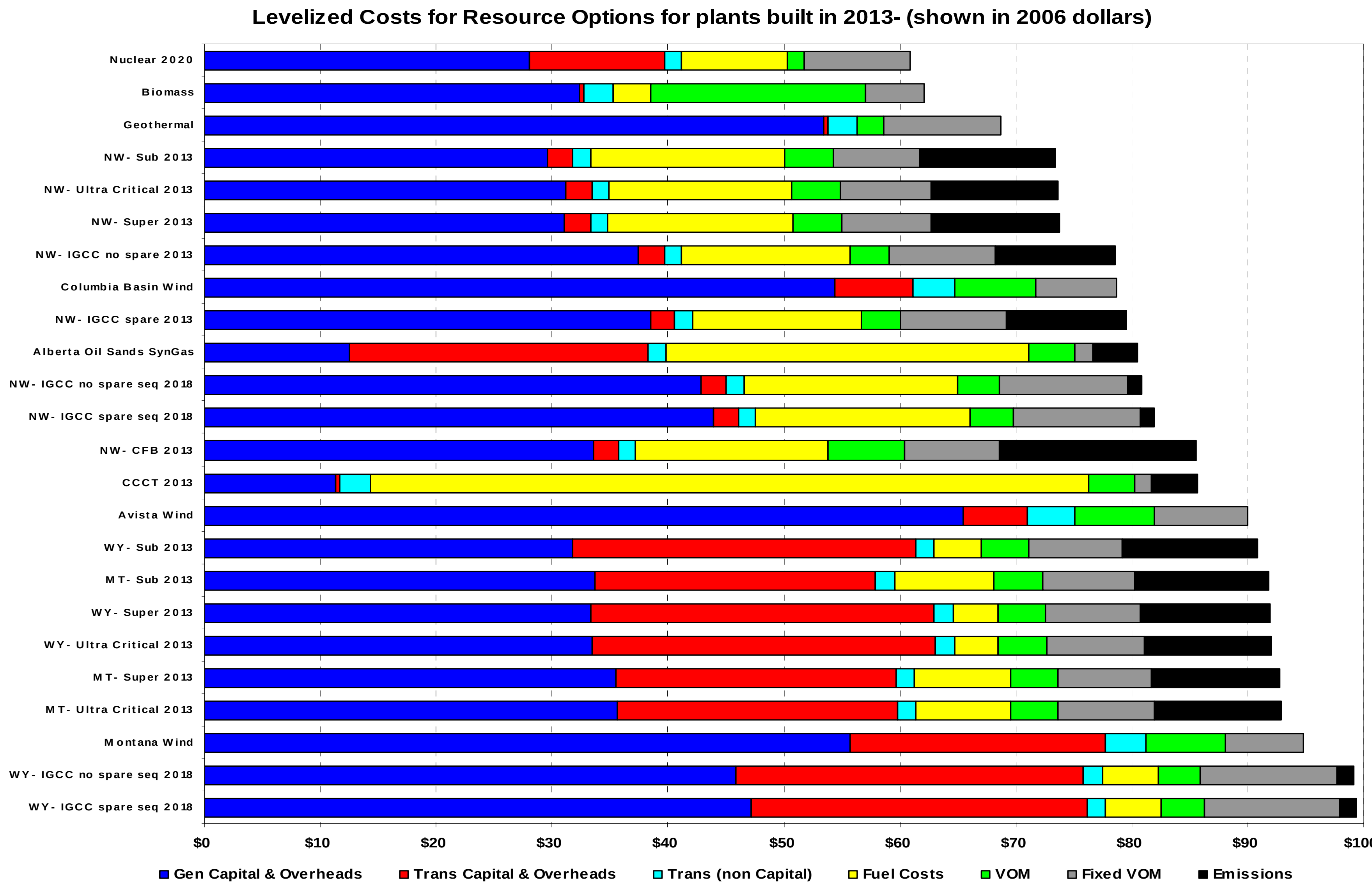
- **Type:** Natural gas-fired 7F-class simple-cycle gas turbine plant
- **Size (MW):** 180
- **Heat Rate (Btu/kWh):** 6,500
- **Fuel Source:** Pipeline natural gas or Syngas
- **Availability:** 2013
- **Capacity Factor:** 90.1%
- **Capital Cost ($/kW):** $722 excluding transmission
- **Variable O&M ($/MWh):** $3.23
- **Fixed O&M (kW/Year):** $9.16
- **Emissions (lbs/mmbtu):** SO_2= 0.0001 NO_X= 0.011 CO_2= 117 Hg= 0.000001
- **Location Options:** Alberta
- **Production Tax Credit:** No

We answer to you.

Nuclear

- **Type:** Advanced Nuclear Power Plant
- **Size (MW):** 1,100
- **Heat Rate (Btu/kWh):** 9,600
- **Fuel Source:** Natural uranium
- **Availability:** 2020
- **Capacity Factor:** 88.0%
- **Capital Cost ($/kW):** $1,992
- **Variable O&M ($/MWh):** $1.16
- **Fixed O&M (kW/Year):** $54.95
- **Emissions (lbs/mmbtu):** N/A
- **Location Options:** Northwest
- **Production Tax Credit:** No

We answer to you.



We answer to you.

Other Modeling Assumptions

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

James Gall

We answer to you. AVISTA

Modeling Overview

AURORAxmp

- North American electric market forecasting tool, it uses fundamental drivers to forecast electric prices
- Tracks value of existing Avista portfolio, as well as potential new portfolios of resources
- The AURORA database is updated to reflect proprietary company data and to reflect regional data not available to the vendor

What's Best®

- Linear Program that is an Excel Add-in, used to optimize models. For this IRP, What's Best is the engine used to solve for the Preferred Resource Strategy Model

@Risk

- Monte-Carlo/Stochastic Excel Add-in that allows for certain variables to be a distribution rather then a single point estimate, used to feed Emissions and Wind data into AURORA

We answer to you. AVISTA

New AURORA Features Utilized for this IRP

- New topology that separates the Northwest Region into eight separate areas with transmission limitations between each area
- Expanded use of Computational Datasets- Allows to run multiple user input iterations, with AURORA built in risk logic
- Operational Pools- Adds the ability for areas to share reserves (e.g. NWPP, CAISO)
- Hydro shaping is shaped to load net of wind generation.
- Transmission losses for individual generators are tracked
- Ability to build regional capacity to a planning margin (not used for draft)

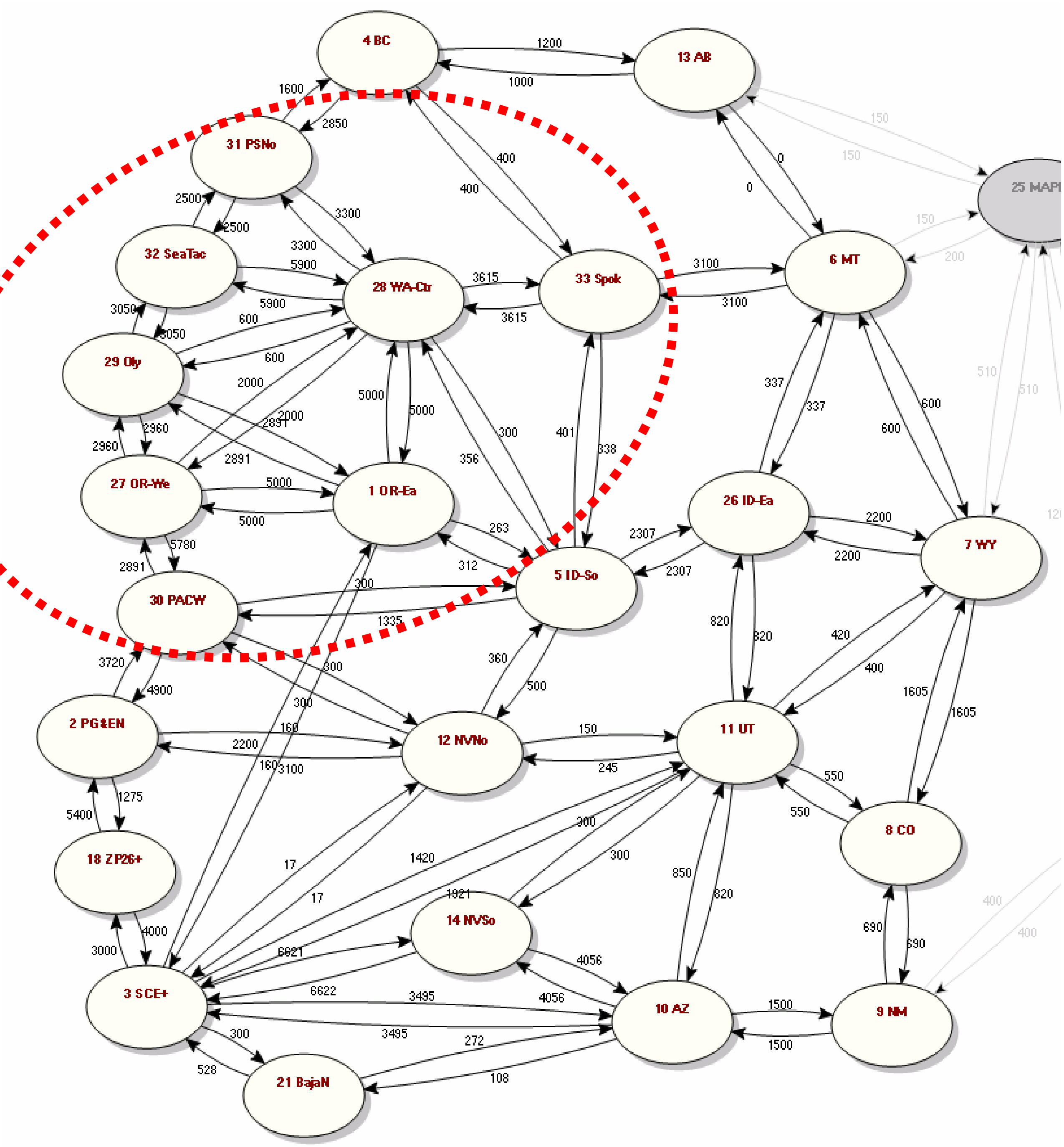
We answer to you.

Changes to Market Modeling Techniques

- Model random forced outages
- Use daily natural gas prices
- Modeling of emissions CO_2, SO_2, NO_X, and Hg prices "taxes" stochastically
- Not modeling wind stochastically, but using hourly generation
- Use of AURORA risk functionality for load and natural gas prices
- Use market hub for pricing/resource evaluation (Mid Columbia/ area 92)
- Focus on resources that change market fundamental for price forecasting (i.e. CCCT, SCCT, coal, wind)
- 70-year median hydro generation is used for capacity expansion, and deterministic studies

We answer to you. AVISTA

AURORA Topology



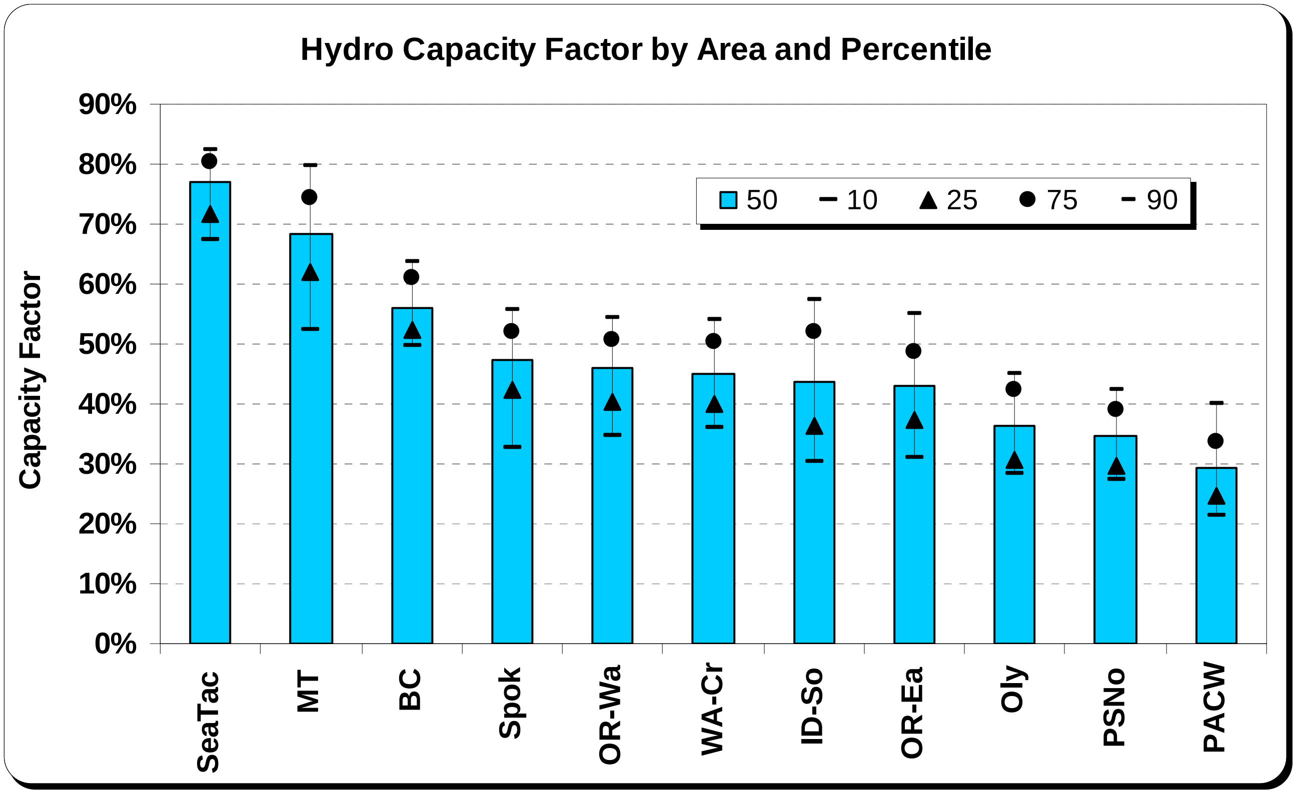
We answer to you. AVISTA

Regional Hydro Modeling

- Uses 04/05 NWPP Headwater Study, with modifications for Canadian Hydro generation and lack of data from Montana.
- Although the data from NWPP study is large, still not all hydro generation is available and updated
  - Hydro capacity available from NWPP study:
    - NW: 99%
    - BC: 47%
    - Idaho: 85%
    - Montana: 79%
- What about the rest of the plants?
  - For BC, total BC hydro generation was available for part of the study, this data was correlated with available generation from NWPP study and generalized for all of the regions hydro
  - For Montana additional generations was available from Yellowtail to increase percent of accounted generation
  - According to NWPP some data within the model has not been updated recently- these plants are not part of the Columbia River or its tributaries these plants were not modified.

Hydro Capacity Factors

- All hydro units within an area share the same generation pattern.
- The bars are the median hydro generation levels used for the capacity expansion and deterministic studies.
- 10, 25, 75, and 90th percentiles are shown for a range in hydro generation used in stochastic studies.

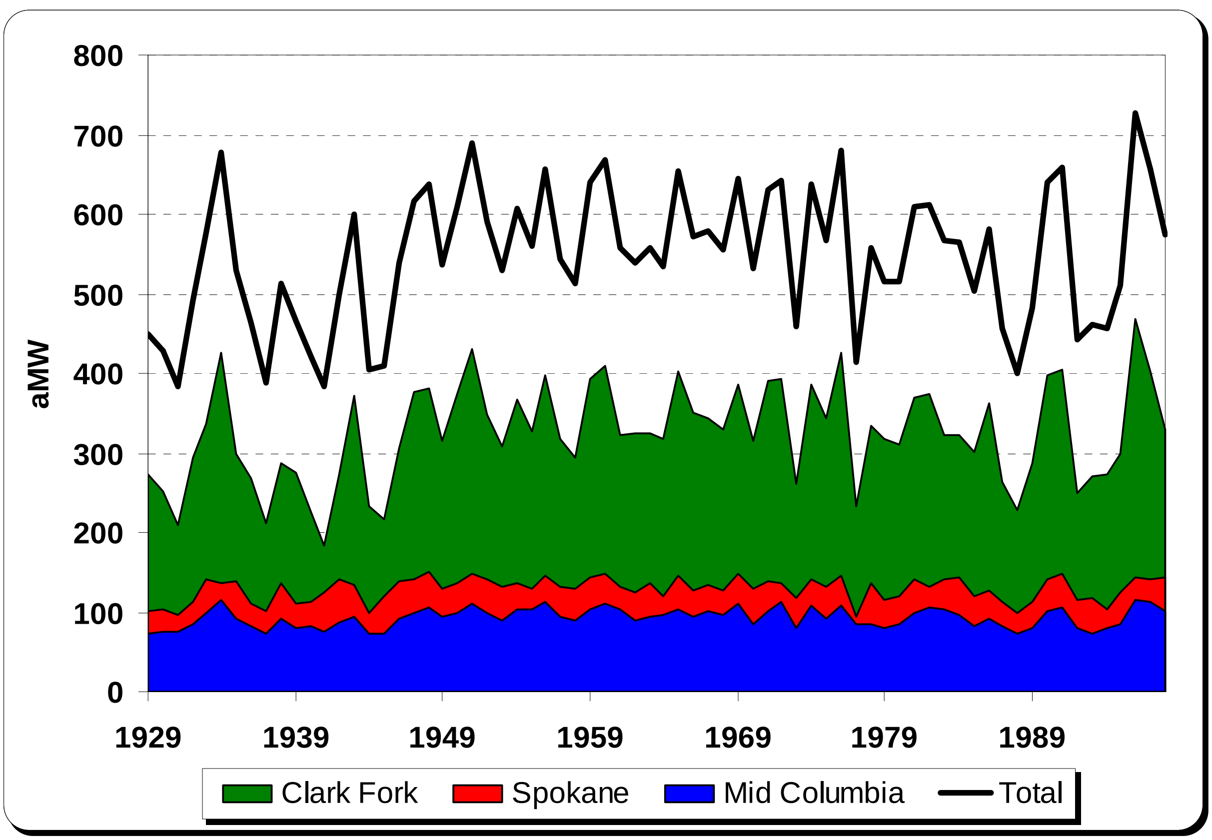


We answer to you.

Avista Hydro Generation

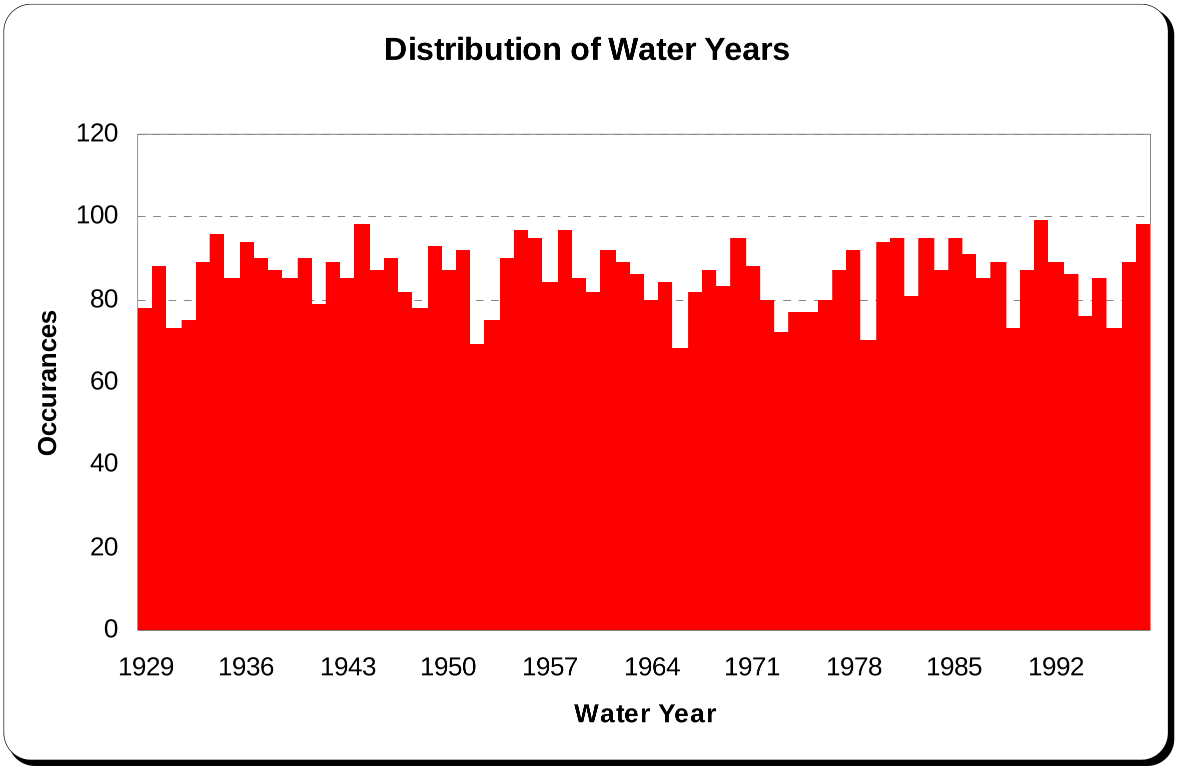
70-Year Hydro Generation for 2008 available generation

- Clark Fork: 325 MW
- Spokane: 129 MW
- Mid Columbia: ~93 MW



Stochastic Hydro

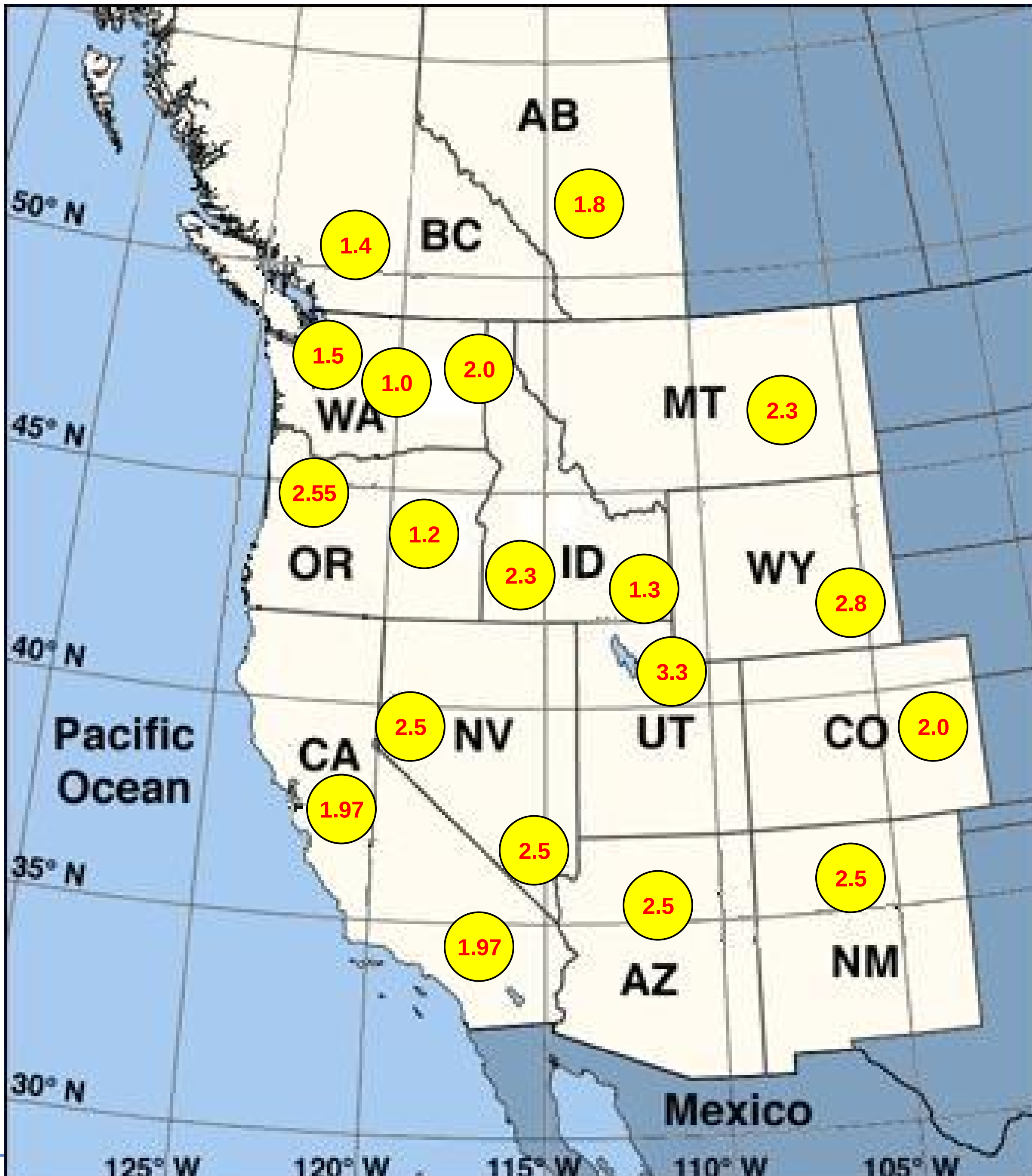
- Each hydro year is randomly drawn for each study year (2008-2027) and each of the 300 iterations
- This methodology attempts to create a uniform distribution of used hydro years of the available 70-year hydro study



We answer to you.

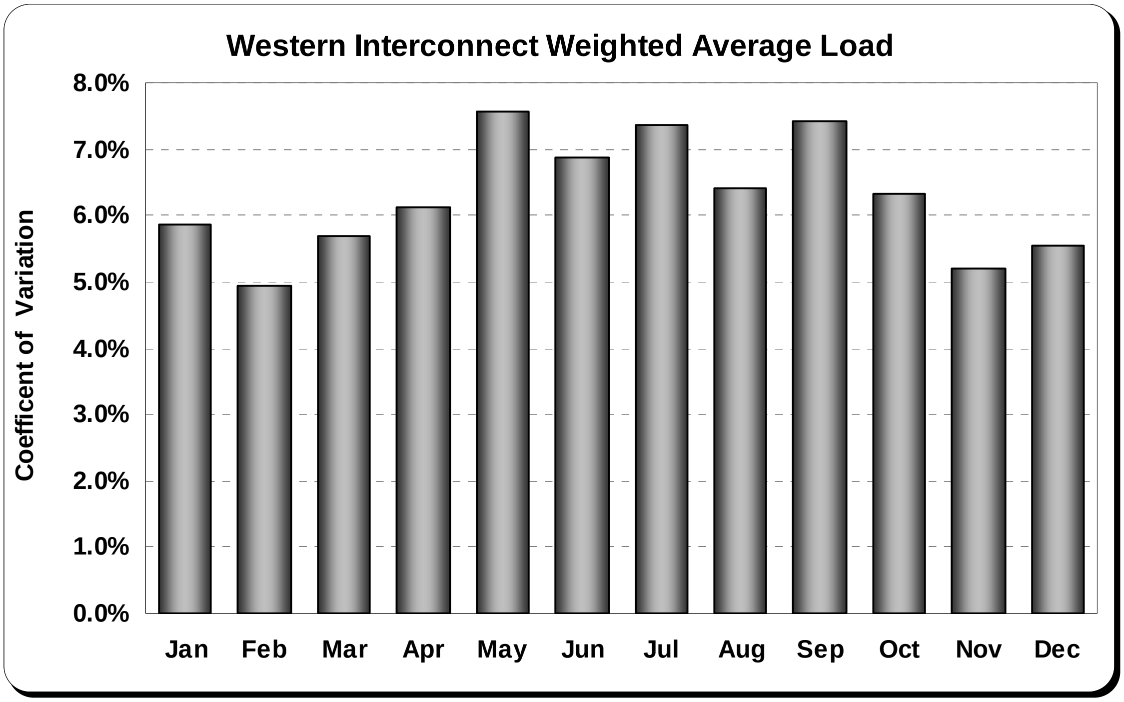
Regional Load Growth

(Annualized Percent Growth)



Load Variability

- All areas modeled have variability component
  - Based on mean and standard deviations of monthly load
  - Uses 2002 to 2004 loads from FERC Form 714
- Each area is correlated to the Spokane area
  - Only areas with statistically significant correlations were included
  - Looked at each weekday separately to eliminate weekly trends
  - Averaged weekday results to obtain final values



We answer to you. AVISTA

Renewable Portfolio Standards

- Western States with Renewable Portfolio Standards (RPS)
  - California
  - Nevada
  - Arizona
  - New Mexico
  - Colorado
  - Montana
- Western States with pending RPS Regulation
  - Washington
  - Oregon
  - Arizona (higher standards)

Base Case includes current and proposed RPS regulations

Northwest Assumptions:

Oregon RPS is same as WA standard,

RPS affects only 90% of WA/OR Load

WA/OR RPS assumptions to be re-evaluated for final study

We answer to you. AVISTA

Wind Modeling

- Wind is modeled similar to that of the 2005 IRP, and uses for the most part the same data.
- Each wind region is modeled hourly.
- A wind model was created using @Risk to create hourly wind patterns using monthly capacity factors and standard deviations, with hourly correlations.
- Wind was not varied stochasticly for the draft study. The final study will use stochastic wind data for potential Avista projects.
  - This draft study assumption overstates wind's ability to hedge our portfolio

We answer to you.

Modeling Overview: Futures & Scenarios

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

John Lyons

We answer to you.

AVISTA

Futures

- A future is stochastically or randomly modeled
- Avista's IRP process models 21 years into the future with 300 Monte Carlo draws of hydro, load, natural gas prices, emissions, and thermal forced outage values
- The benefits of using futures lies in their ability to quantitatively asses market risks
- The disadvantages to using futures include the large amount of computational power needed for the exercise, as well as the difficulty of understanding the results of the exercise
- Each future takes about 2,700 hours of computing time and generates nearly 62 GB of data

We answer to you.

Scenarios

- Scenarios are modeled by using average levels of hydro, load, gas prices, wind, emissions, and forced outages
- One or more variable is then changed
- Advantages for scenarios include quicker solution times and more understandable results due to the limited number of changes to underlying model assumptions

Uses of Futures and Scenarios

- Scenarios and futures are used to help understand the impacts and size of the impacts on a variety of different assumptions about the future on such things as:
  - Wholesale electric market
  - Different resource options
  - Avista's current load & resource portfolio
  - The Preferred Resource Strategy

We answer to you.

AVISTA

2007 IRP Market Futures (Stochastic)

- **Base Case** – assumes average hydro, gas, and load conditions
- **Zero Carbon Tax** – assumes no carbon tax is enacted
- ***McCain/Lieberman Carbon Tax*** *– based on Climate Stewardship Act*
- **More Volatile Natural Gas** – doubles the price volatility of gas
- ***Shift in Gas (high) 50% up*** *– increases gas price escalation by 50%*
- ***Shift in Gas (low) 50% down*** *– decreases gas prices escalation by 50%*
- ***Increase WECC load escalation 50%*** *– WECC loads increase 50% faster than in the Base Case*
- ***Decrease WECC load escalation 50%*** *– WECC loads increase 50% slower than in the Base Case*

We answer to you.

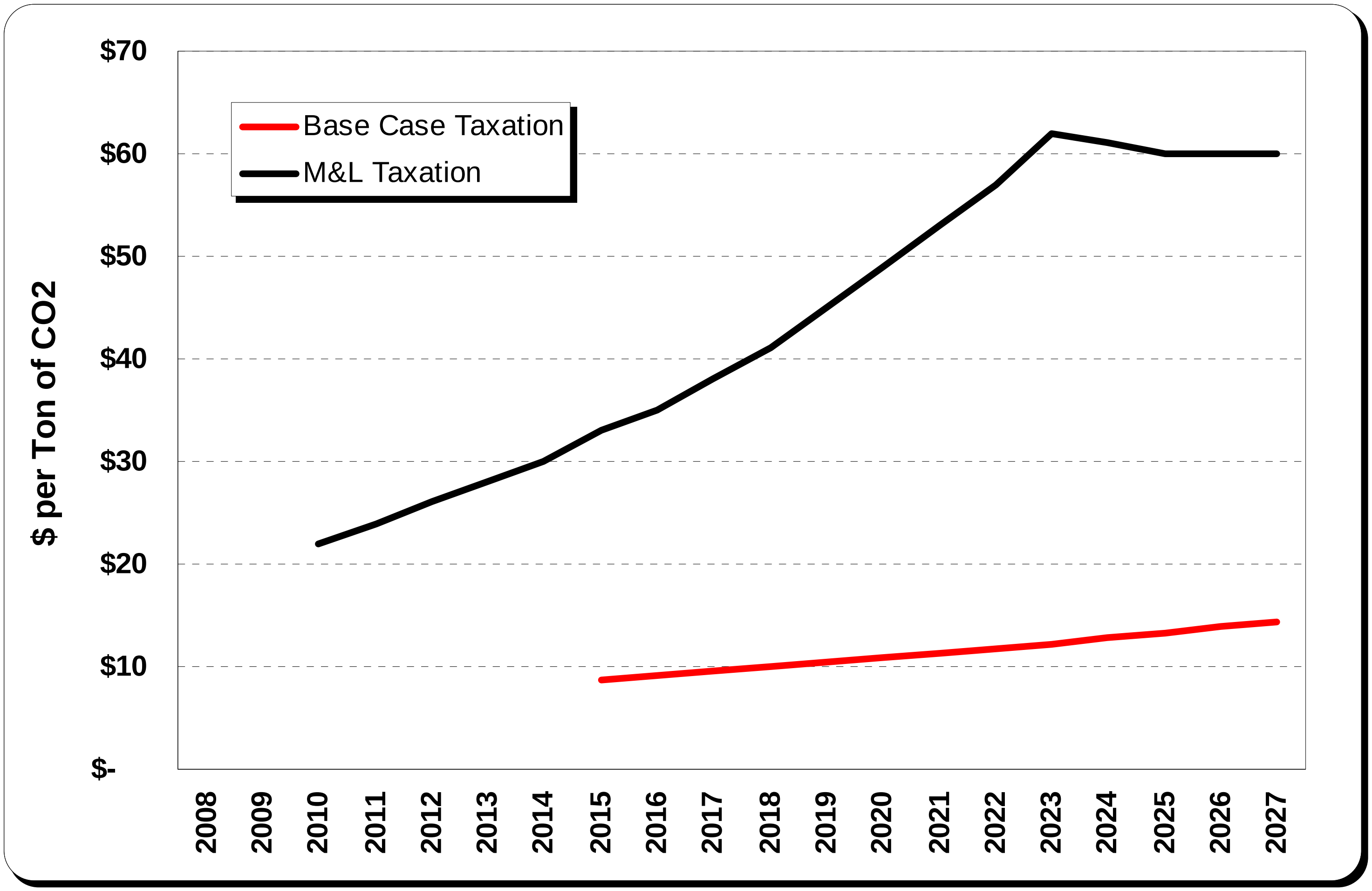
AVISTA

2007 IRP Market Scenarios (Deterministic)

- **Unlimited Nuclear begin 2015** – model is allowed to build as much cost-effective nuclear power as possible
- **Electric Car** – assumes a surge in the number of plug-in cars and light trucks amounting to 10% penetration per year
- **Gas & Wind Build** – only gas and wind resource allowed to be constructed
- **Global Warming** – shifted weather conditions cause changes in the timing of the hydro run off
- **No Gas Plants after 2013** – does not allow the construction of new gas-fired plants after 2013
- **No WA/OR RPS** – assumes that the RPS is not passed in Oregon or Washington

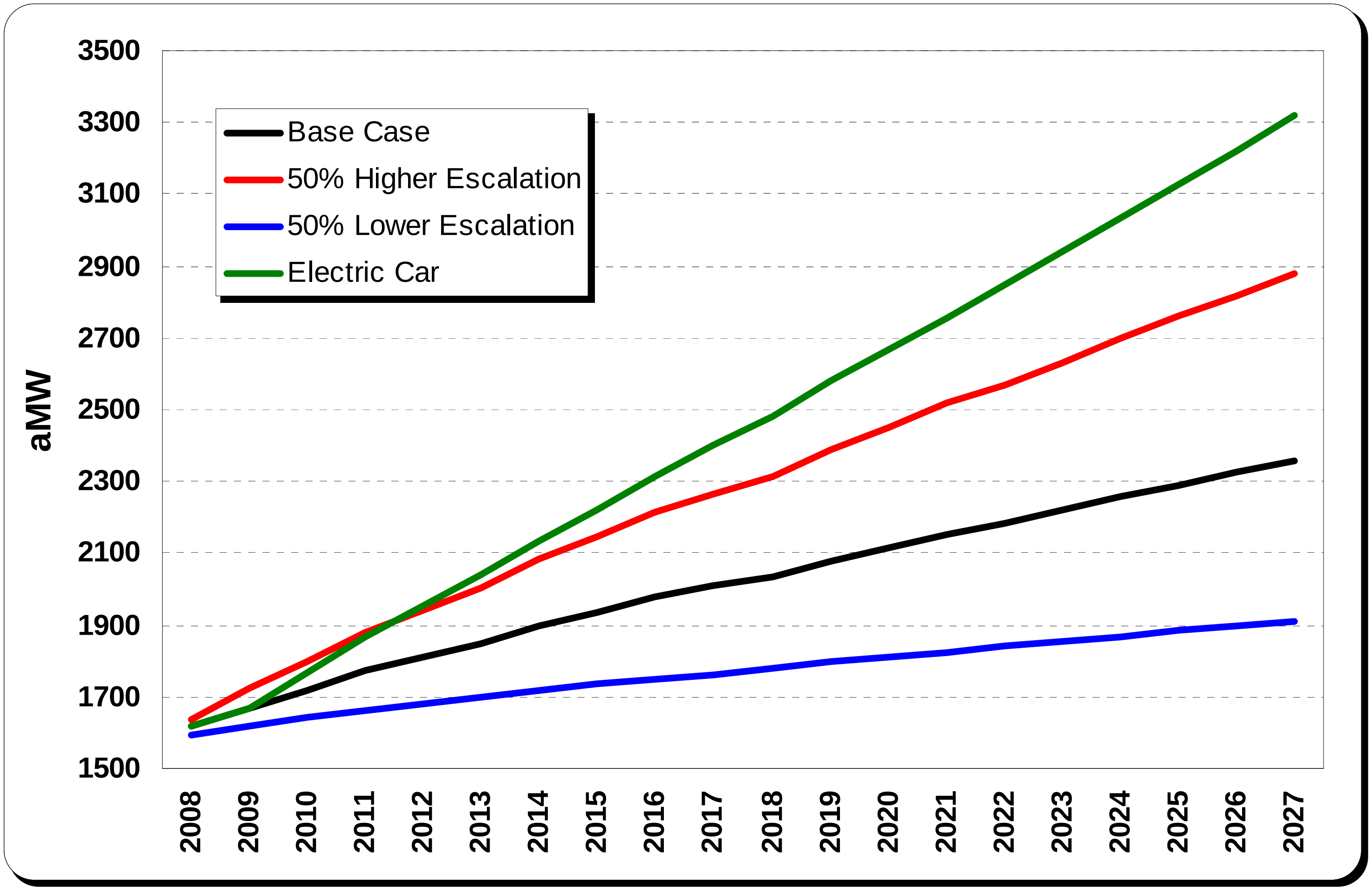
We answer to you.

Base Case vs. McCain & Lieberman CO_2 Tax



We answer to you. AVISTA

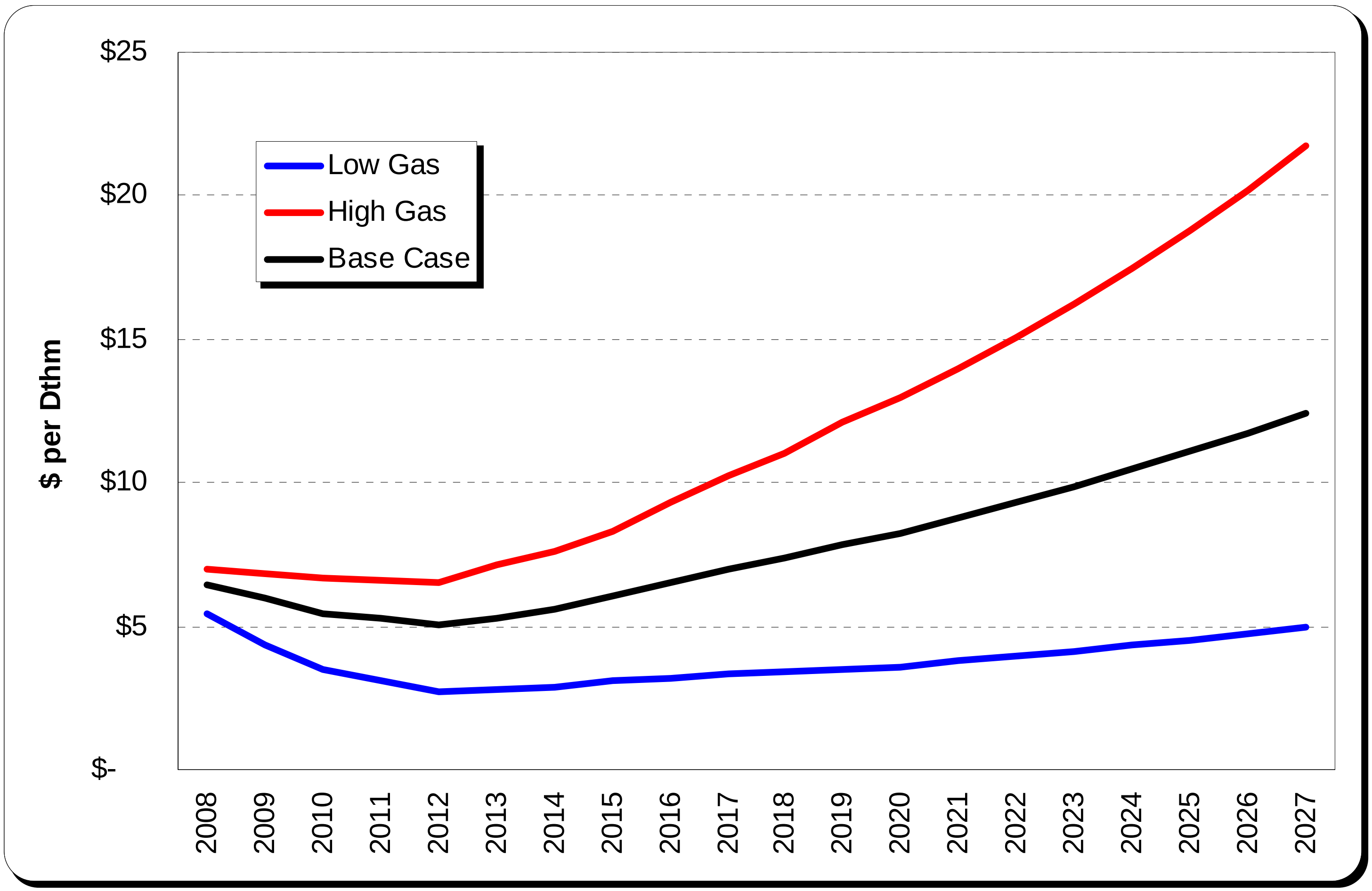
Load Growth: Eastern Washington Energy



We answer to you.

AVISTA

Gas Price Scenarios - Sumas



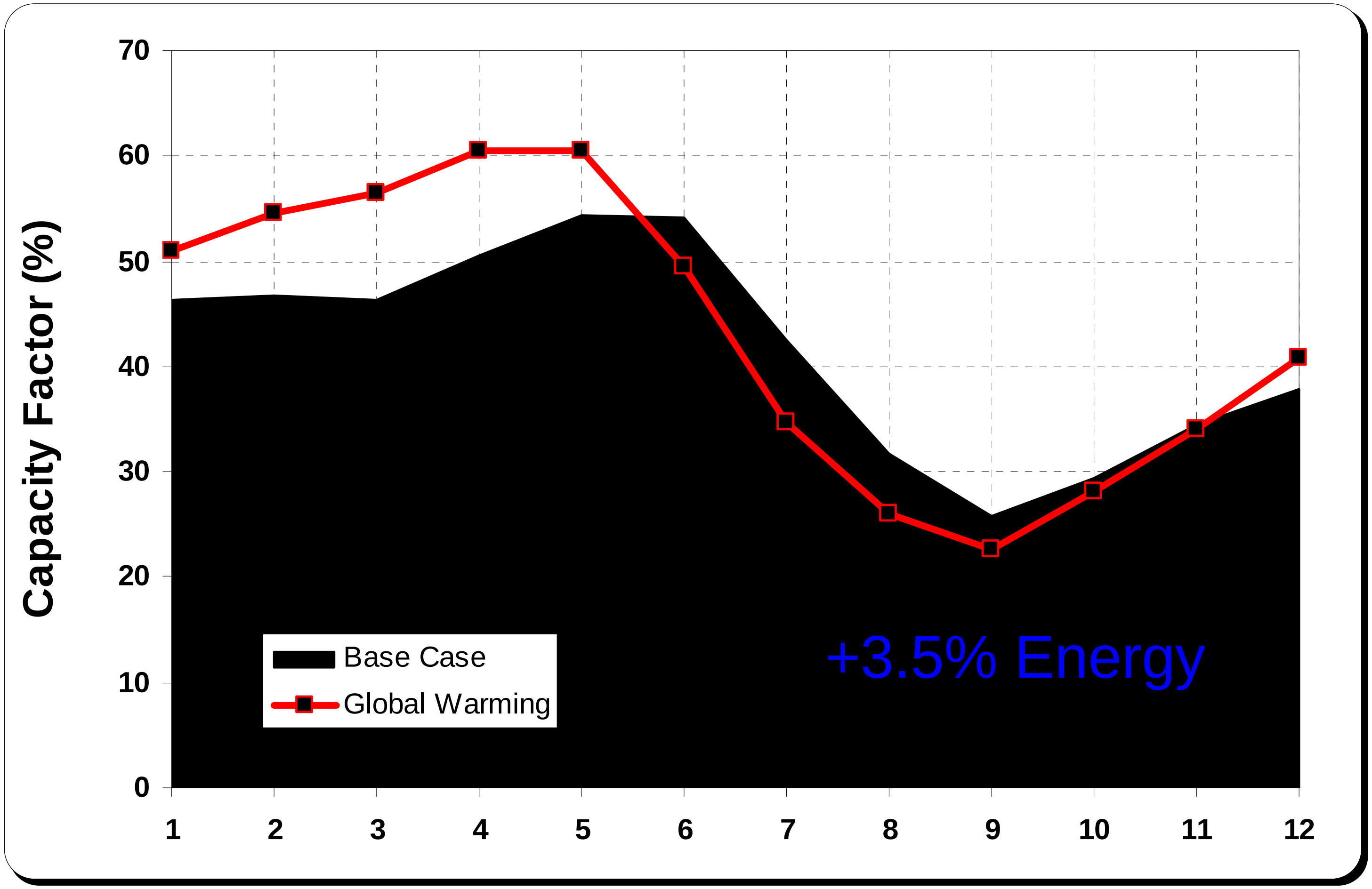
Nominal Levelized Costs

$9.63

$6.73

$3.55

Global Warming Scenario- NW Hydro CF



We answer to you.

AVISTA

Fuel Price Forecasts

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

James Gall

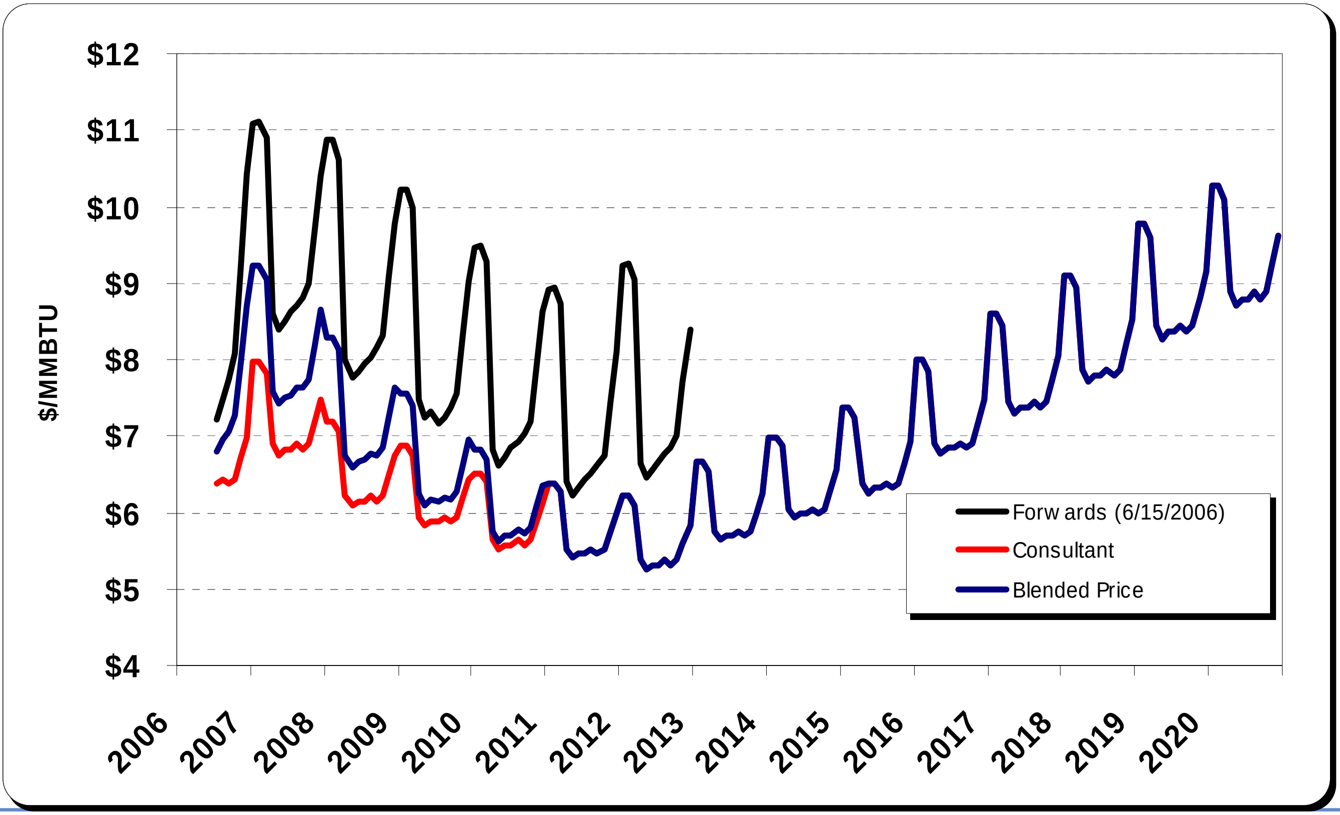
We answer to you.

Levelized Natural Gas and Coal Costs

20-Year Levelized (2008 to 2027) shown in 2006 dollars	Nominal Price per Dthm	Real Price per Dthm
Henry Hub NG	$7.47	$6.31
AECO NG	$6.58	$5.56
Sumas NG	$6.73	$5.68
Mine Mouth PRB Coal	$0.38	$0.32
Short Haul PRB Coal	$0.76	$0.64
Long Haul PRB Coal	$1.42	$1.20

Methodology

- NYMEX forwards (6/15/2006)
- Long-term fundamentals based forecast (consultant)
- Prices after 2020 grow at 2019/20 growth rate



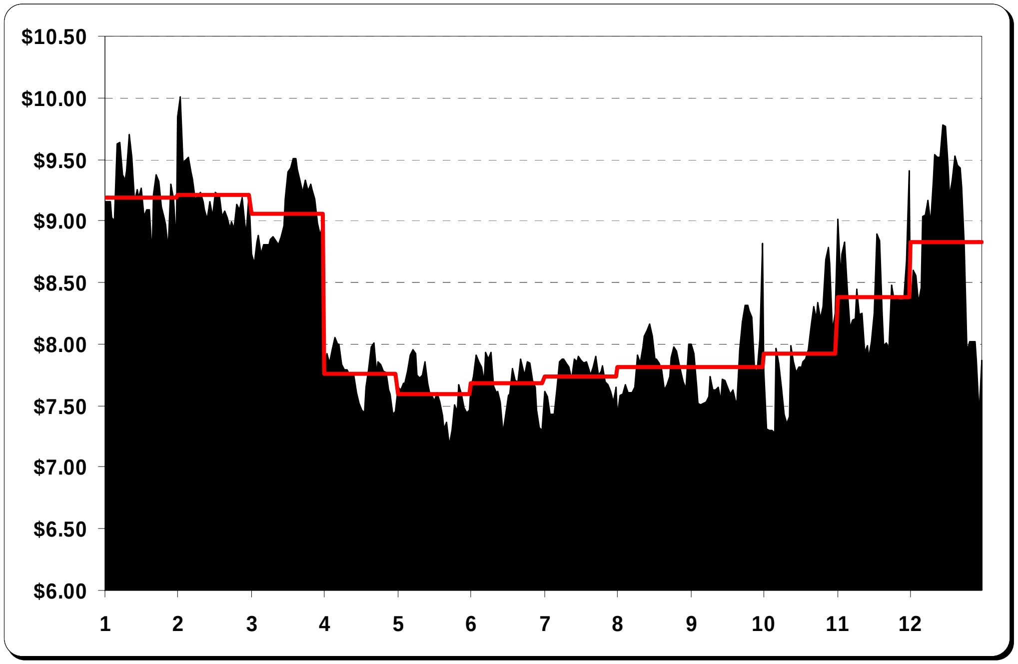
We answer to you.

Intra Year Gas Prices

Month	Percent of Annual	Month	Percent of Annual
Jan	111%	Jul	95%
Feb	111%	Aug	96%
Mar	109%	Sep	95%
Apr	96%	Oct	96%
May	94%	Nov	100%
Jun	95%	Dec	104%

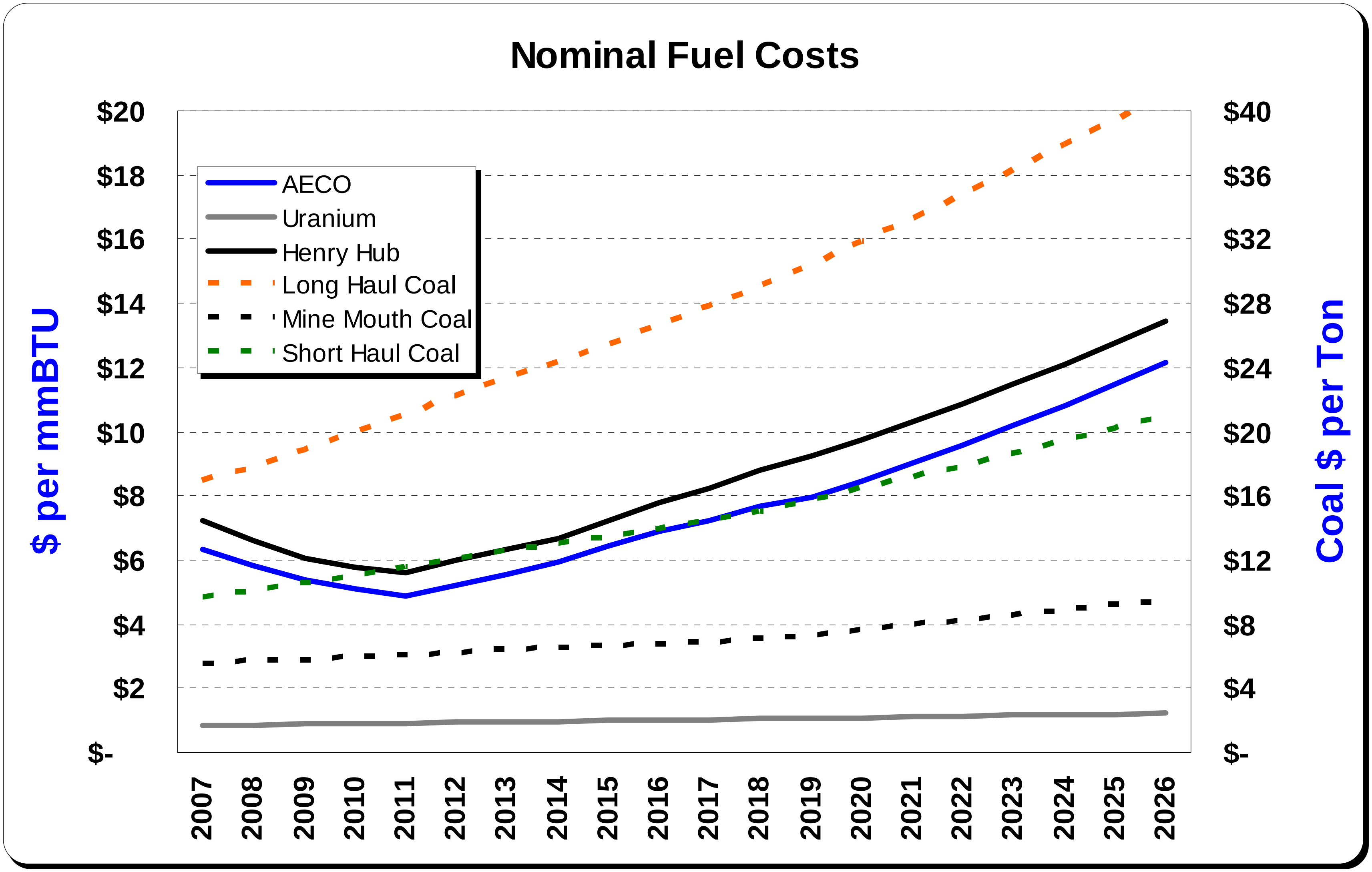
Monthly Gas Shape: Consistent with 2006 Gas IRP, average of monthly forward prices available on July 1, 2005 (these prices were used to avoid hurricane related price skews). All gas prices use this monthly shape.

Daily Gas Shape: Average daily percent change from the monthly average price from 2003 to 2006 at AECO



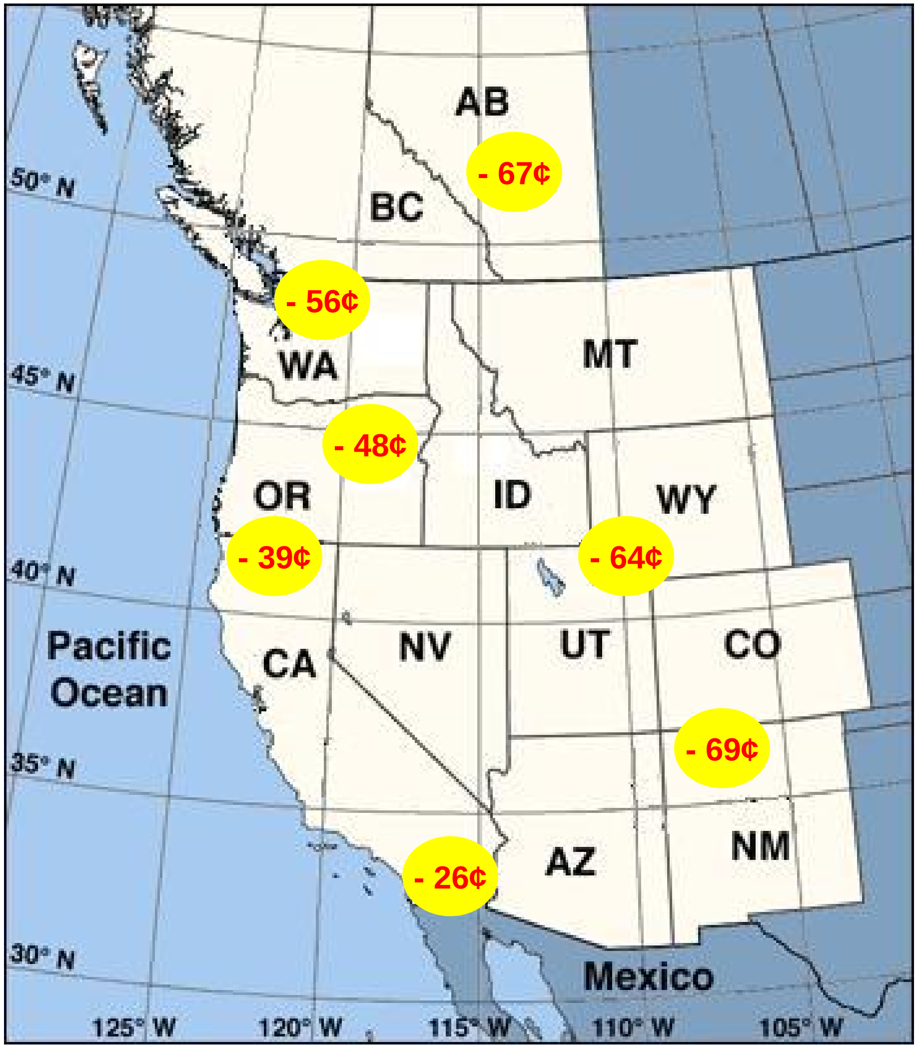
We answer to you.

AVISTA



We answer to you.

Basin Differentials/Gas Transportation

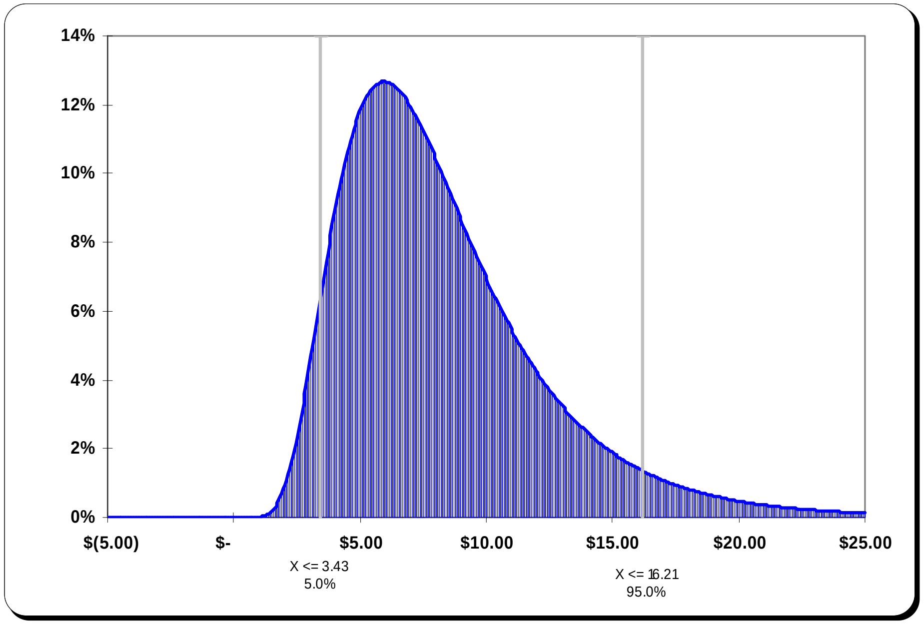


- Differentials are based on long-term forecast by a Consultant between 2008 and 2020, shown as a delta from Henry Hub
- Prices shown are a nominal levelized cost between 2008 & 2027, values are shown in 2006 dollars
- Differentials after 2020 use the rate of growth from 2019/20 for all time periods thereafter

We answer to you.

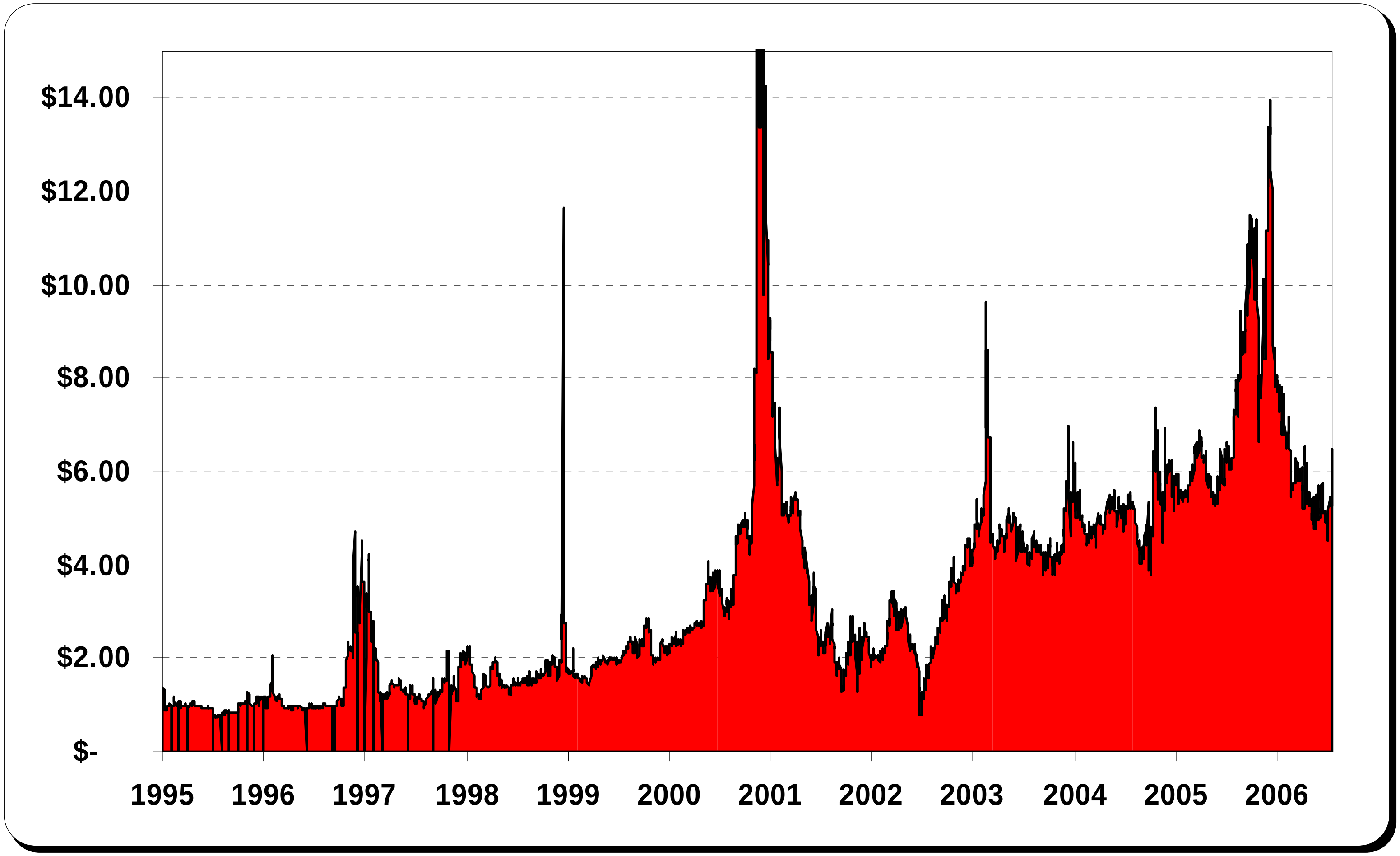
Stochastic Gas

- How do we model uncertainty
- 300 independent monthly draws of a lognormal distribution using the gas forecast as the mean and a standard deviation of 50% of the mean.
- The example below is for January 2007



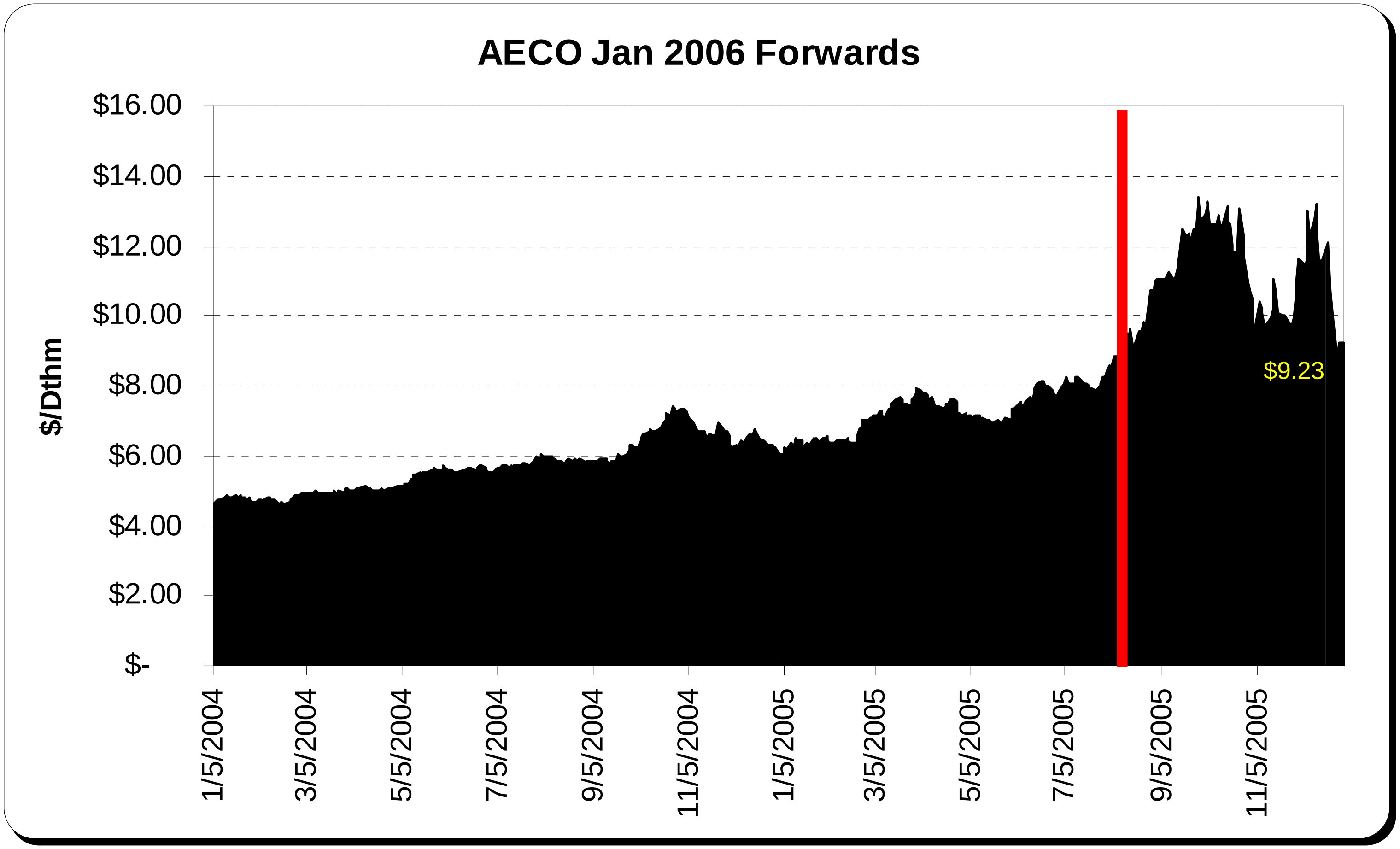
We answer to you.

Historical Daily Sumas NG Prices



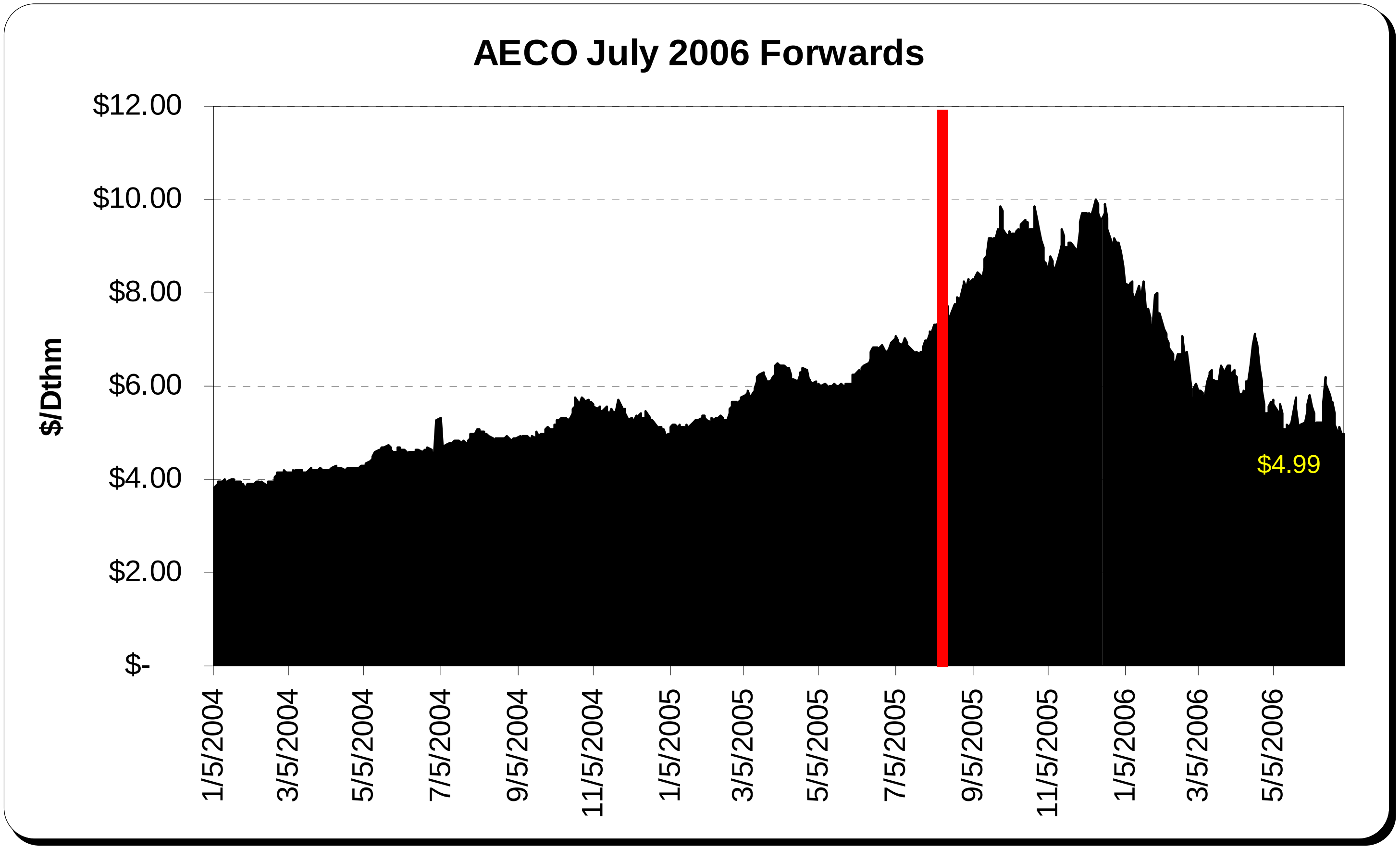
We answer to you.

Historical Volatility (forward prices)



Mean: $7.26
Stdev: $2.22

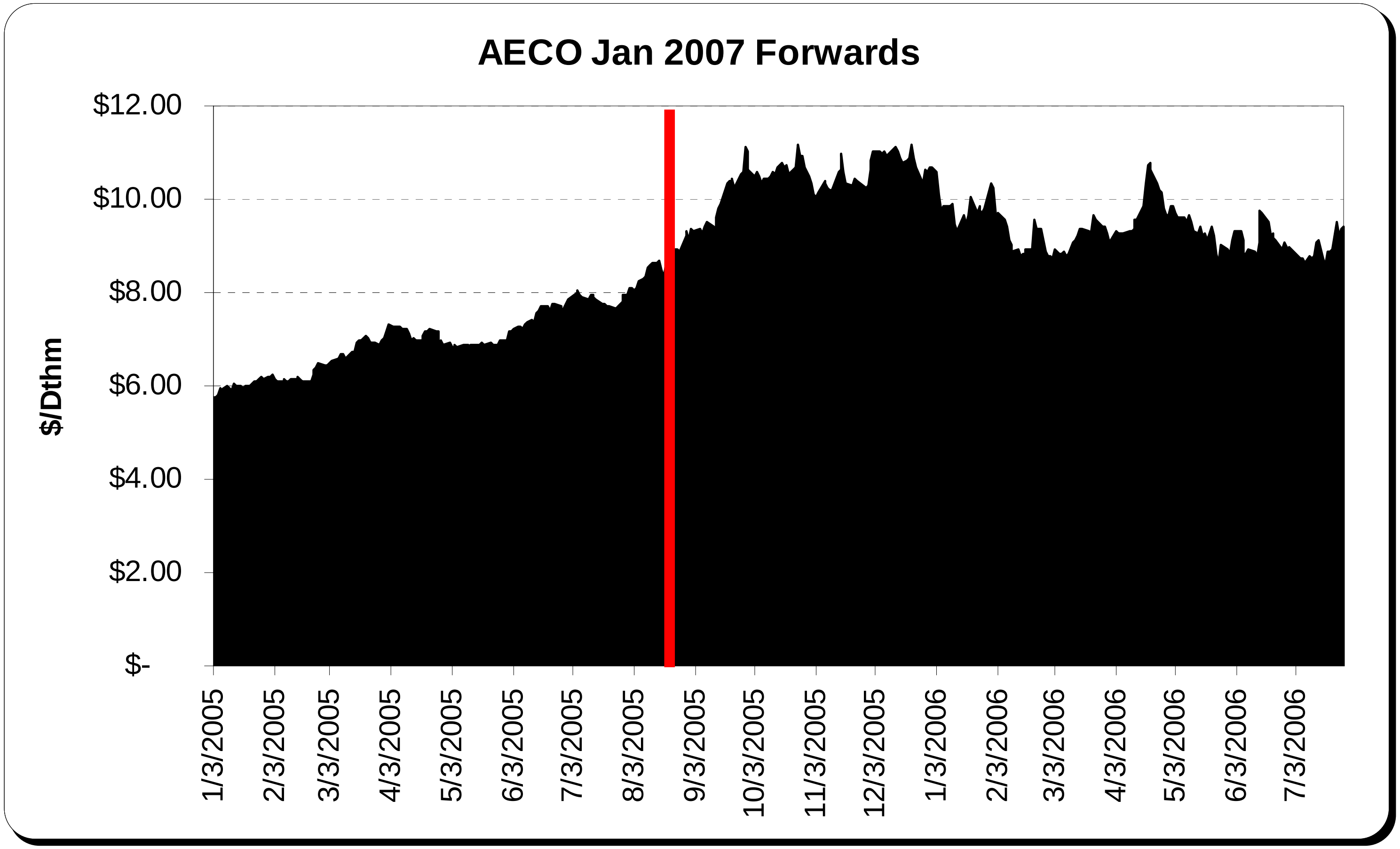
Historical Volatility (forward prices)



Mean: $6.03
Stdev: $1.59

We answer to you.

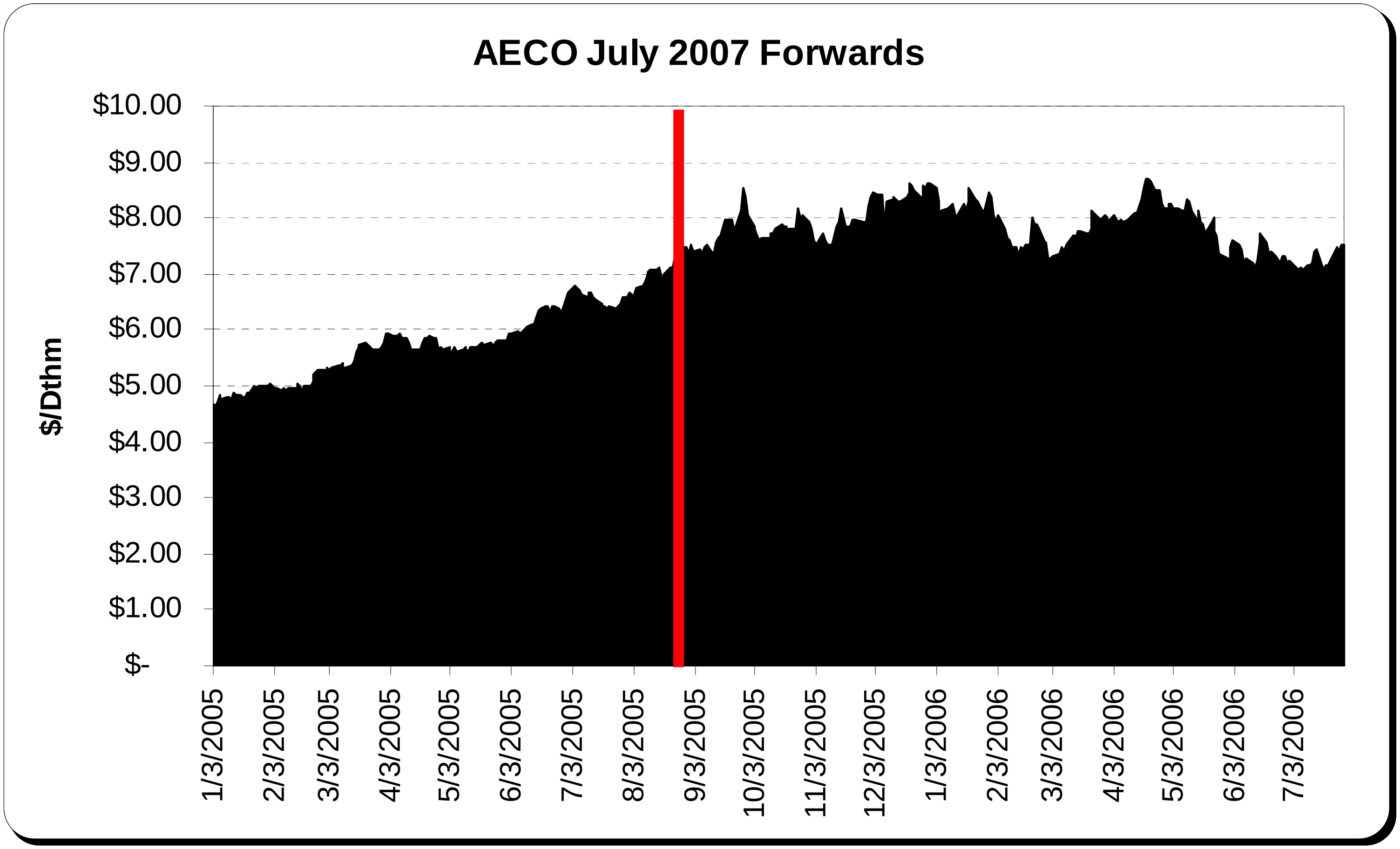
Historical Volatility (forward prices)



Mean: $8.64
Stdev: $1.51

We answer to you.

Historical Volatility (forward prices)



Mean: $6.99
Stdev: $1.14

We answer to you.

AVISTA

IRP Modeling Overview: Preliminary Transmission Costs & Paths

2007 Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

Heidi Heath

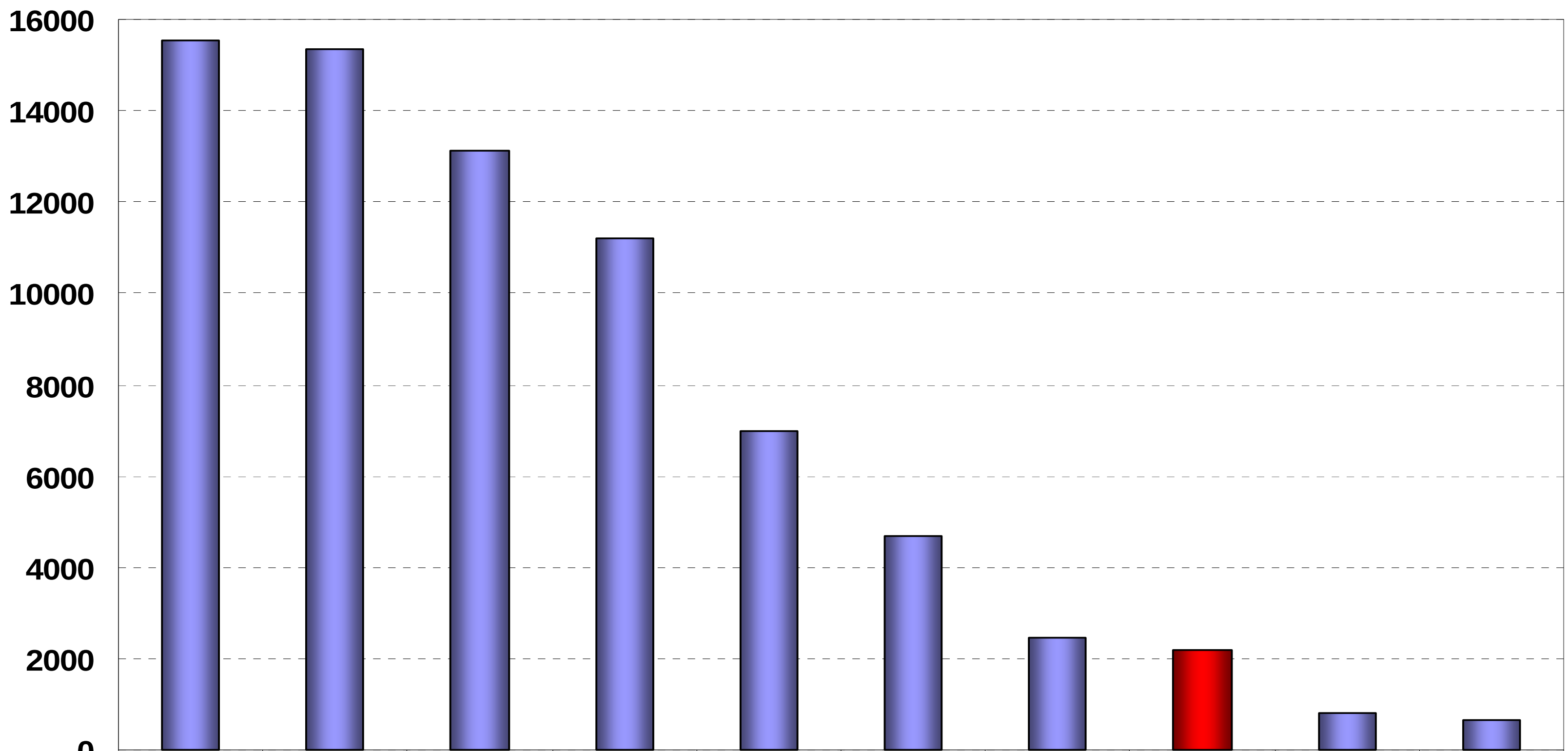
We answer to you.

Avista currently owns:

- 623 miles of 230 kV line
- 1537 miles of 115 kV line
- 11% interest in 495 miles of a 500 kV line coming from Colstrip

We answer to you.

Miles of High-Voltage Transmission Lines



	Pacifi Corp	BPA	Alberta	BC Hydro	North-western	Idaho Power	Sierra Pacific	Avista	PGE	SCL
Miles	15530	15342	13132	11185	7000	4671	2446	2169	815	657

We answer to you.

Current and Planned Upgrades

- Reconstructed 230 kV line from Rathdrum to Spokane
- Constructed 230 kV Dry Creek substation near Clarkston, Washington
- Added 230-115 kV transformer bank at Boulder Substation for Spokane Valley Reinforcement
- Reconstructed Pinecreek 230 kV Substation
- Constructing 60 miles of 230 kV transmission line between Benewah and Shawnee substations to relieve congestion (Oct 2007)
- Increasing capacity of two 230 kV lines from Beacon substation to Bell substation (March 2007)

We answer to you.

Other Upgrades in Avista's Service Territory

- Bonneville recently upgraded the Coulee-Bell line, replacing the 115 kV line with a 500 kV line
- Bonneville recently relocated Bell lines running along Highway 395 in preparation for a new freeway in Spokane
- Bonneville is reconductoring and replacing poles on the Franklin-Walla Walla 115 kV line

We answer to you.

AVISTA

Regional Transmission Issues

- Coordinated transmission planning
- RTO development and funding
- Cost allocation
- Wind integration issues

We answer to you.

AVISTA

ColumbiaGrid RTO

- FERC Order 2000 requires transmission owners to develop and submit a proposal to establish an RTO, or to explain why such an organization cannot be developed.
- ColumbiaGrid formed March 31, 2006
- Avista is one of six founding members of ColumbiaGrid, with Puget Sound Energy, Seattle City Light, Grant County PUD, Chelan County PUD, and Bonneville Power Administration. Tacoma Power is also a member.

We answer to you.

Transmission Modeling in the IRP

- Various locations for potential resources were studied by the transmission department
- Cost estimates currently use 2005 IRP data
- There are several issues and uncertainties regarding expansion of the transmission system:
  - Firm transmission capacity is scarce in many areas so integrating large-scale resources will be difficult
  - No comprehensive regional planning process for transmission expansion issues
  - BPA is unable to finance new transmission construction due to restrictions on federal borrowing authority
  - Multi-jurisdictional siting and permitting issues exist for new large-scale transmission expansion

Generation Integration Cost Estimates

- Transmission data from the 2005 IRP used for this study
- Updated estimates will be provided for the final 2007 IRP

We answer to you.

Eastern Montana

350 MW – probably not available
- 500 kV series capacitors and other upgrades
- $100 million

750 MW
- 500 kV series capacitors, 230 kV upgrade in eastern Washington
- $400 million

1000 MW
- Major 500 kV facilities
- $1.5 billion

We answer to you.

Mid-C Projects

Includes all projects delivering power at Mid-C (wind, nuclear, oil sands, etc.)

350 MW

- $100 million

750 MW

- $150 million

1000 MW

- $800 million

We answer to you.

AVISTA

Southern Washington

Currently 115 kV, planned upgrade to 230 kV in 2007

350 MW

- Little new transmission required, $10 million

750 MW

- 230 kV reinforcement, $80 million

1000 MW

- Major 500 kV facilities required, $1.5 billion

We answer to you.

AVISTA

Northern Idaho

Currently 230 kV line

350 MW

- Little new transmission required, $10 million

750 MW

- 230 kV reinforcement, $70 million

1000 MW

- Major new 500 kV facilities required, $1.5 billion

We answer to you.

AVISTA

West of Spokane

Currently 115 kV line, suitable for integration of 40-50 MW

350 MW

- New 230 kV double circuit line required, $50 million

750 MW

- Additional upgrades required, $100 million

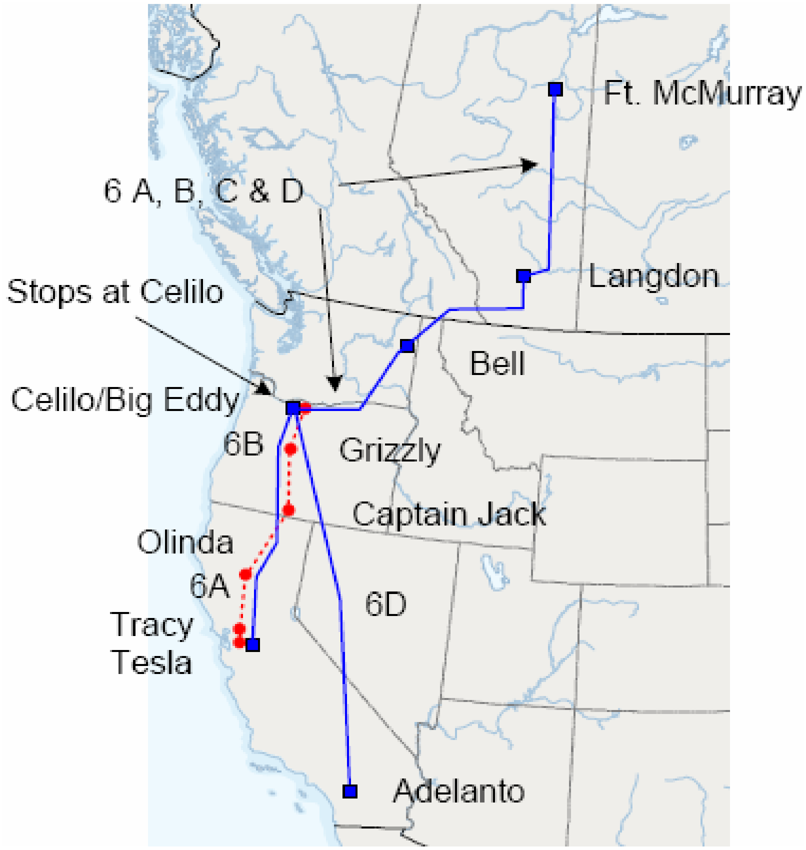
1000 MW

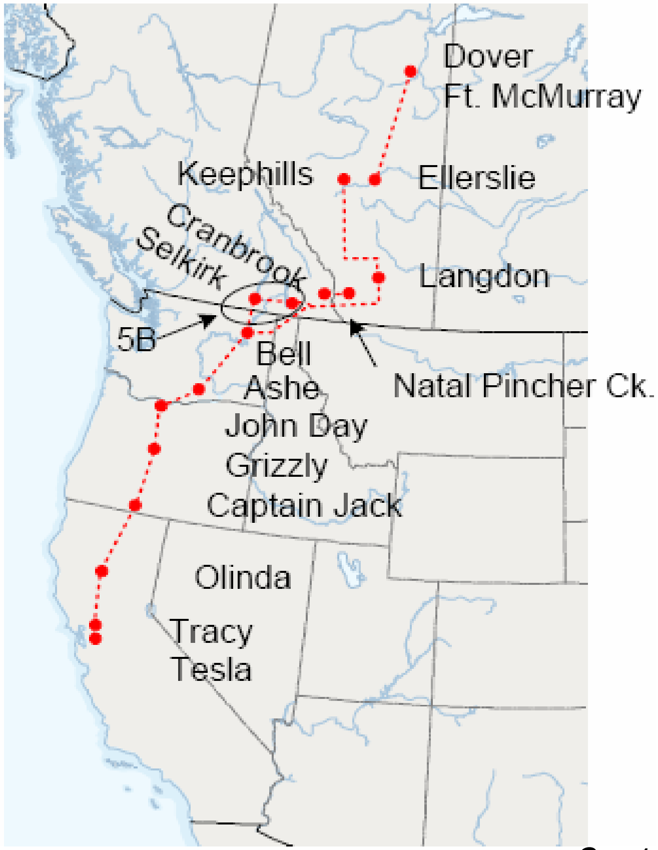
- Major new 500 kV facilities required, $1.5 billion

We answer to you. AVISTA

Alberta Oil Sands

Several options: AC or DC lines, delivery at Bell or Mid-C





Courtesy of NTAC

We answer to you.

Alberta Oil Sands

- For current study $2.445 billion was the assumed cost of the line to bring power from Fort McMurray to the Northwest
- The Northwest Transmission Assessment Committee recently studied several transmission options. Prices are estimated to be between ~1 billion to ~2 billion. Consideration will be given to these prices in the final report.

We answer to you.

AVISTA

Future Resource Requirements

2007 Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

Heidi Heath

ENERGY AT WORK

We answer to you.

AVISTA

Future Resource Requirements

- New resource requirements are determined by the net balance of expected loads and resources.
- Energy and capacity values for expected loads and resources are calculated twenty years into the future and are included in Planning L&R's.
- First deficit expected for energy and capacity in 2011

We answer to you. AVISTA

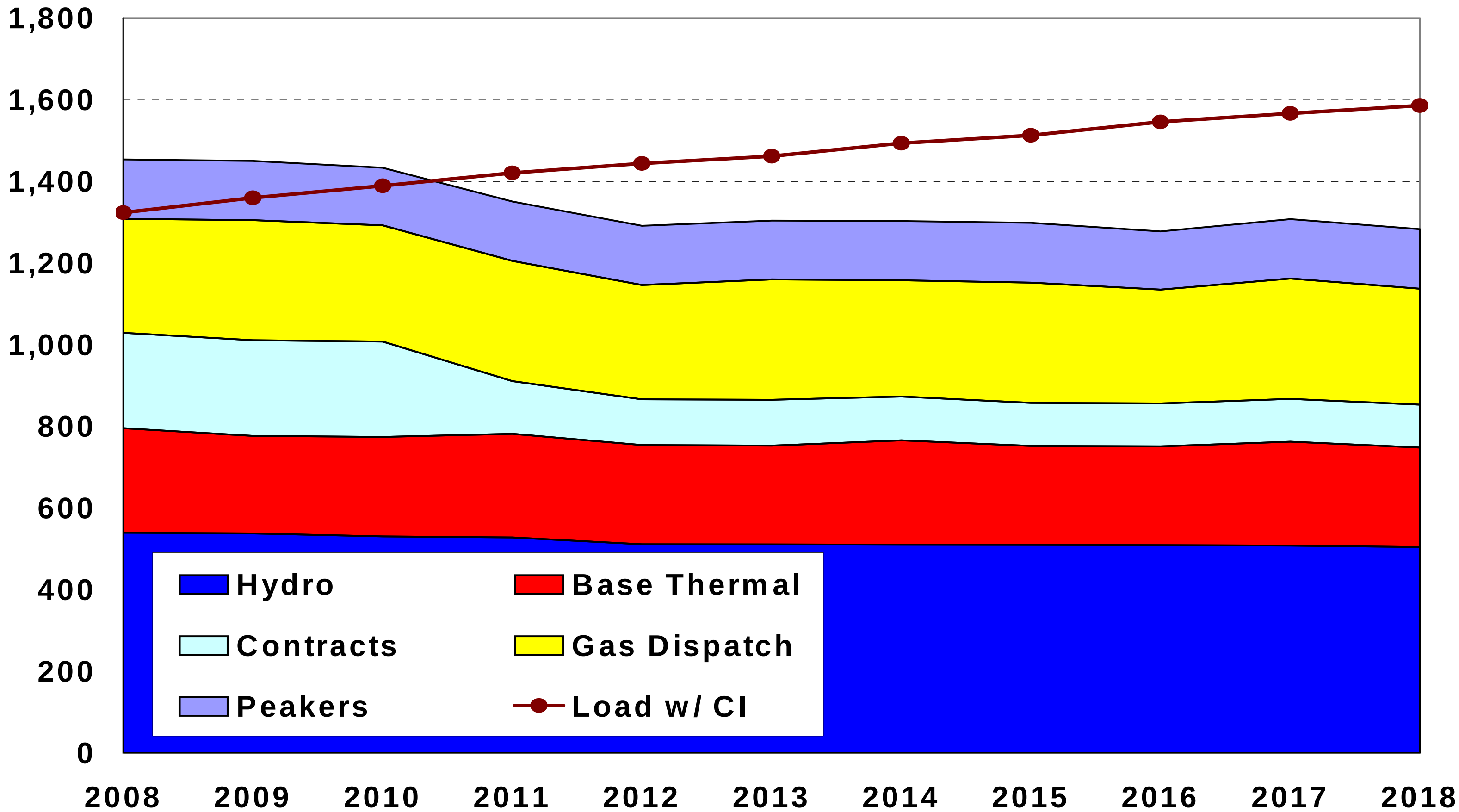
Energy Loads and Resources

	Last Updated August 14, 2006	Notes	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	AVERAGE LOAD & HYDRO PLANNING											
	REQUIREMENTS											
1	System Load	1	(1,124)	(1,161)	(1,194)	(1,226)	(1,252)	(1,270)	(1,302)	(1,321)	(1,354)	(1,375)
2	Contract Obligations	2	(61)	(61)	(60)	(60)	(59)	(59)	(59)	(59)	(59)	(11)
3	Total Requirements		(1,185)	(1,222)	(1,254)	(1,286)	(1,311)	(1,329)	(1,361)	(1,380)	(1,413)	(1,385)
	RESOURCES											
4	Contract Rights	4	295	295	294	189	172	172	166	164	164	116
5	Hydro	3	540	538	531	528	512	511	510	510	509	509
6	Base Load Thermals	5	256	239	244	254	243	242	256	243	242	254
7	Gas Dispatch Units	6	279	294	284	294	279	294	284	295	279	294
8	Total Resources		1,370	1,366	1,353	1,266	1,205	1,219	1,217	1,211	1,194	1,173
9	**POSITION**		**185**	**145**	**99**	**(20)**	**(106)**	**(110)**	**(144)**	**(169)**	**(218)**	**(212)**
	CONTINGENCY PLANNING											
10	Confidence Interval	7	(167)	(166)	(163)	(162)	(159)	(159)	(159)	(159)	(159)	(159)
11	WNP-3 Obligation	8	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)
12	Peaking Resources	9	145	145	141	146	145	144	146	146	142	145
13	**CONTINGENCY NET POSITION**		**130**	**90**	**44**	**(70)**	**(152)**	**(158)**	**(191)**	**(215)**	**(268)**	**(259)**

We answer to you.

AVISTA

Energy L&R – Annual Resource Capability



We answer to you.

AVISTA

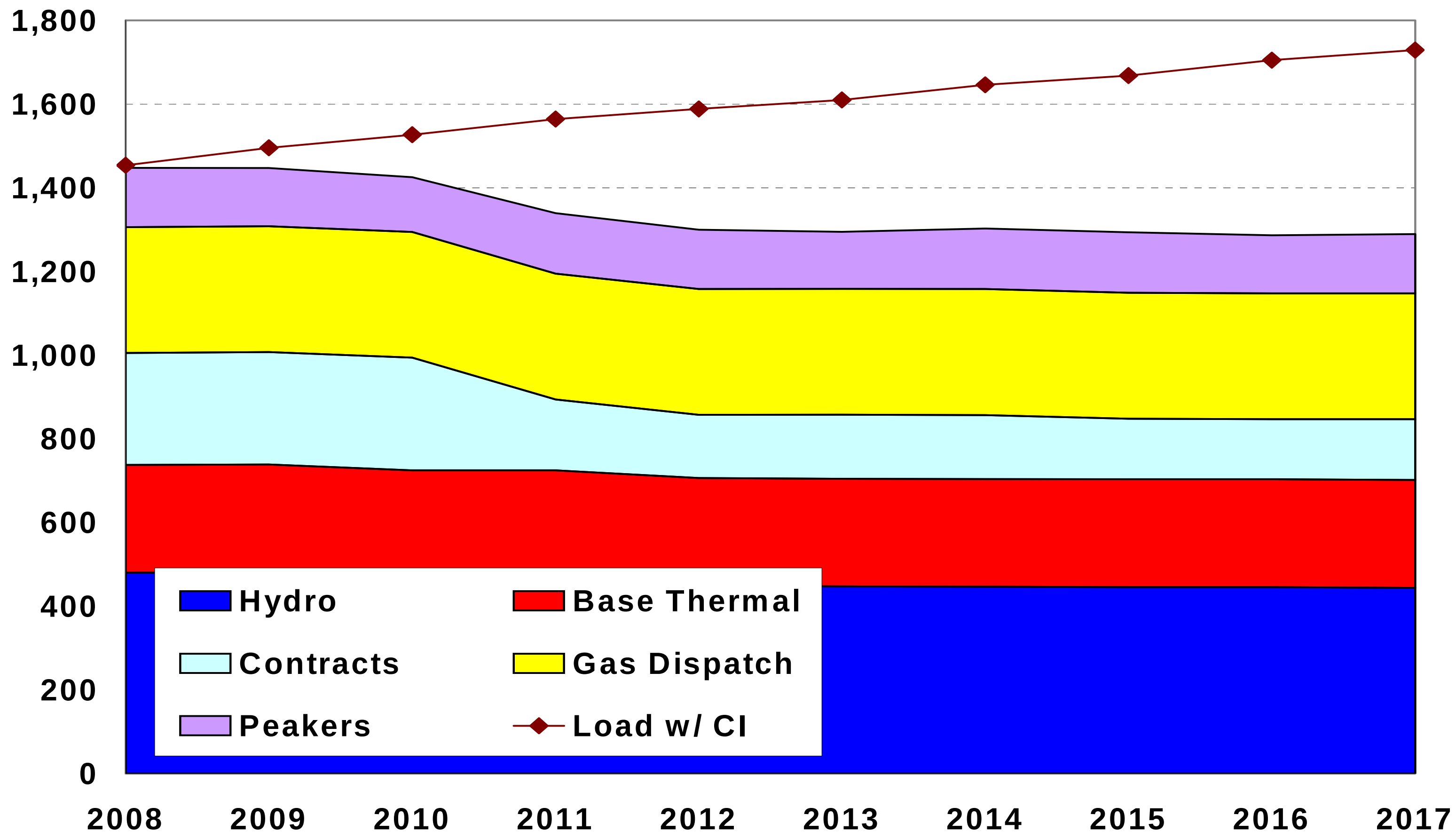
Energy L&R – Annual Resource Capability

	2008	2009	2010	2011	2012	2017	2022	2027
Load w/ CI	1,324	1,360	1,390	1,421	1,444	1,567	1,649	1,777
Contracts	234	234	234	129	113	105	106	106
Hydro	540	538	531	528	512	509	491	491
Base Thermal	256	239	244	254	243	254	243	242
Gas Dispatch	279	294	284	294	279	294	284	294
Peakers	145	145	141	146	145	145	145	145
Total Resources	1,454	1,450	1,434	1,351	1,292	1,308	1,269	1,278
Load/Resources Balance	130	90	44	-70	-152	-259	-380	-499

We answer to you.

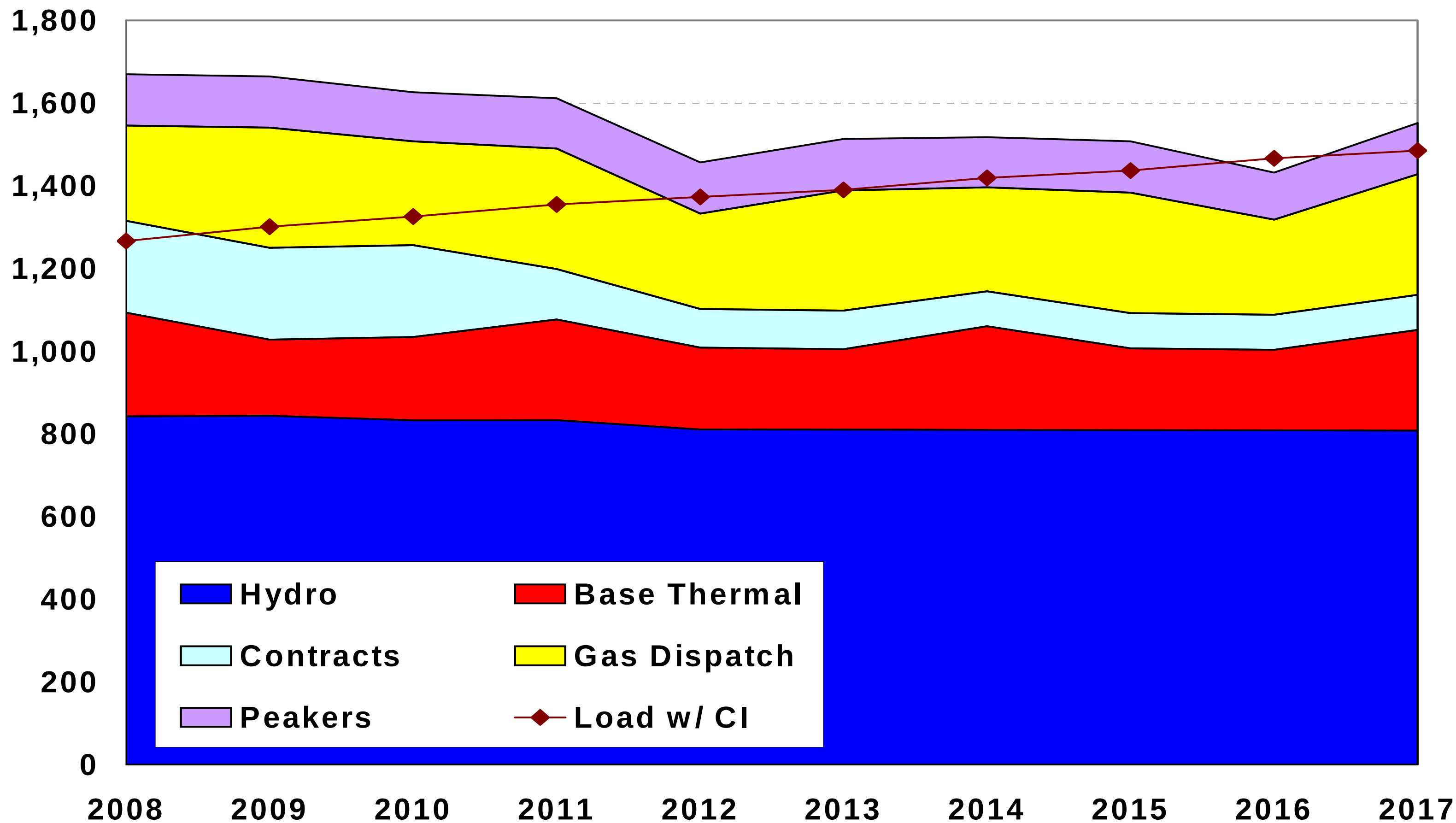
AVISTA

Energy L&R – First Quarter Resource Capability



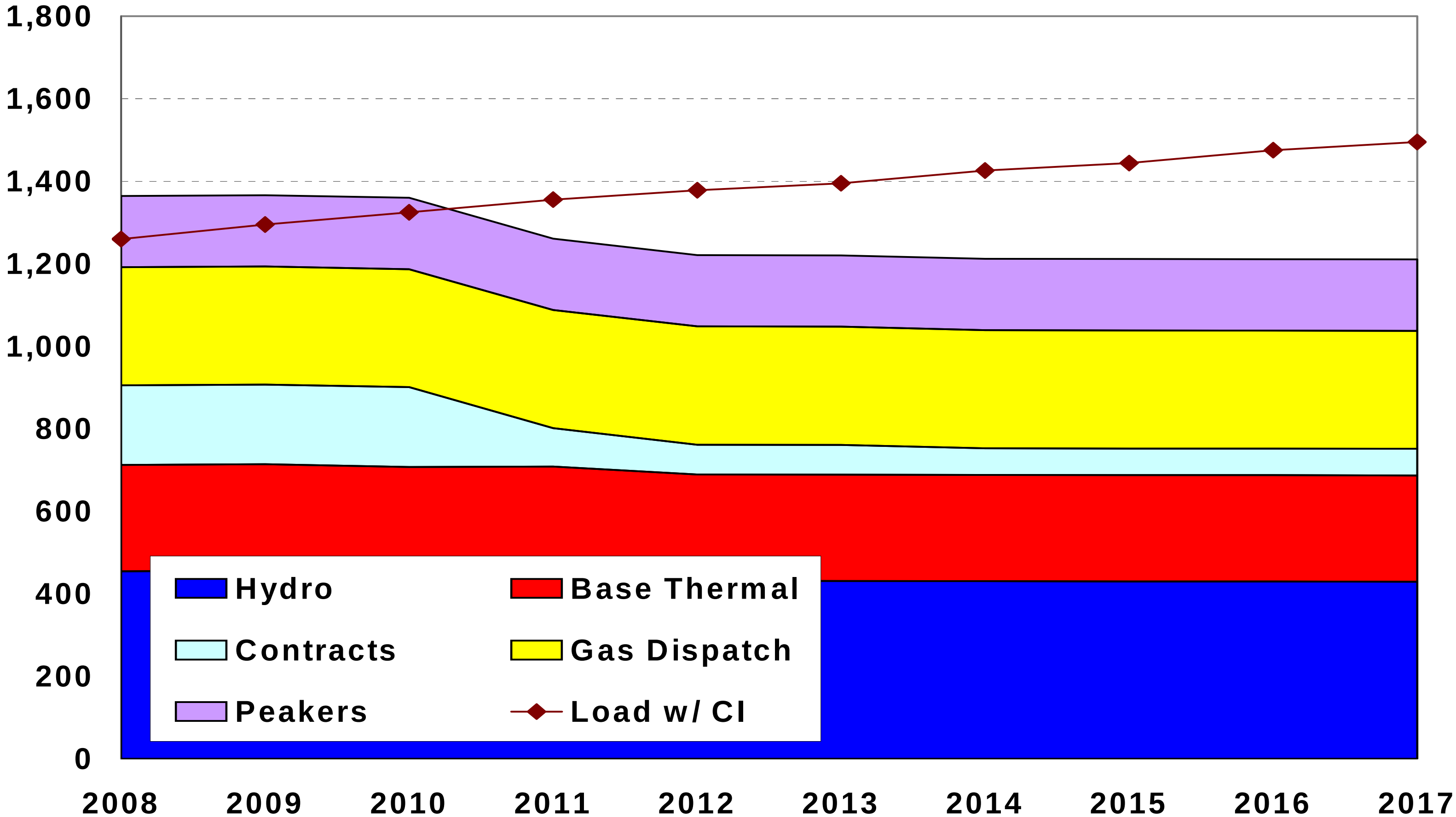
We answer to you.

Energy L&R – Second Quarter Resource Capability



We answer to you. AVISTA

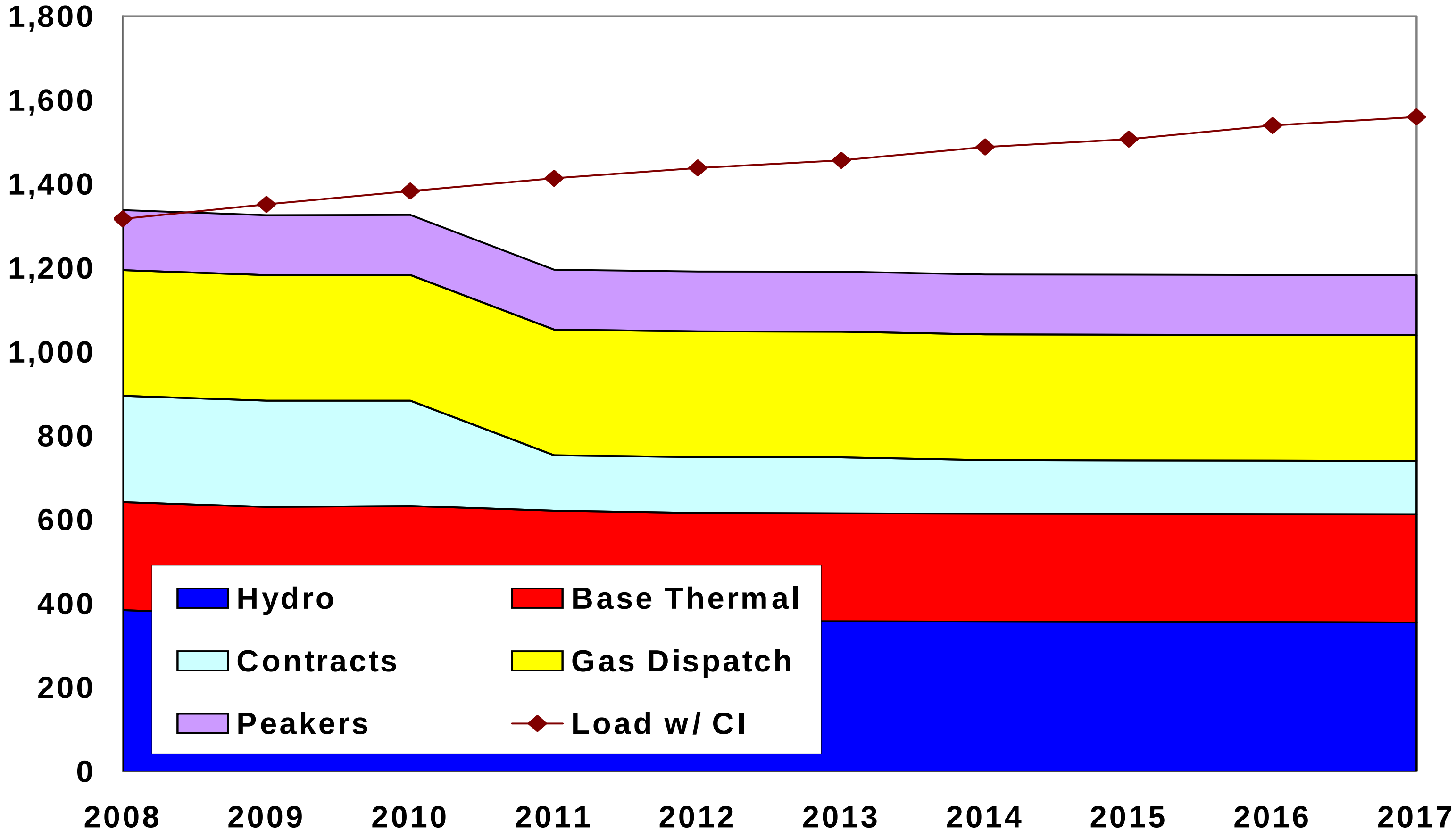
Energy L&R – Third Quarter Resource Capability



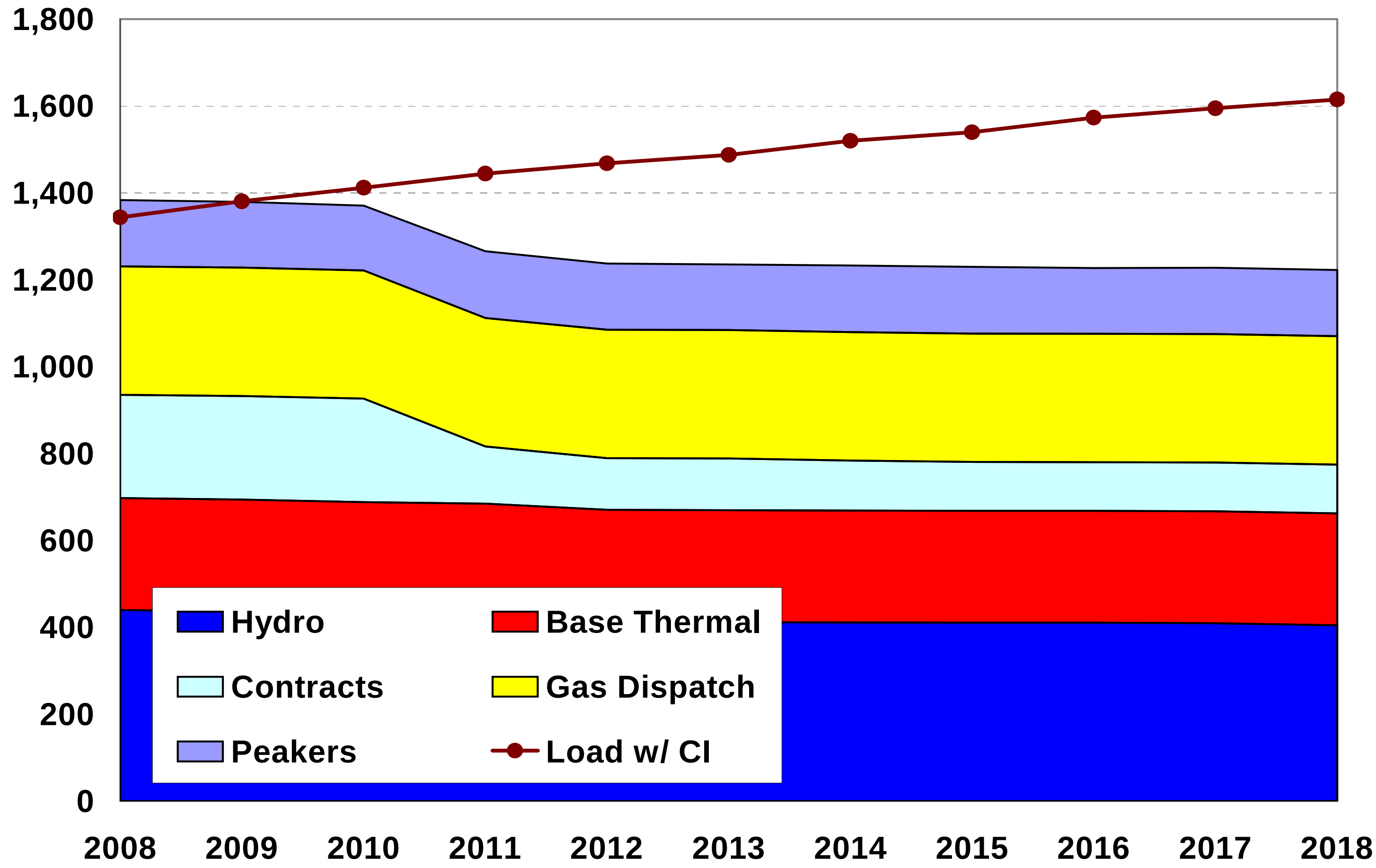
We answer to you.

AVISTA

Energy L&R – Fourth Quarter Resource Capability



Energy L&R – Annual Capability Without Q2



We answer to you.

AVISTA

Energy L&R – Annual Capability Without Q2

	2008	2009	2010	2011	2012	2017	2022	2027
Load w/ CI	1,343	1,381	1,412	1,444	1,468	1,595	1,679	1,812
Contracts	238	238	238	132	119	112	113	113
Hydro	440	437	431	427	413	410	393	393
Base Thermal	258	258	258	258	258	258	258	258
Gas Dispatch	296	296	295	296	296	296	296	296
Peakers	153	152	149	153	153	153	153	153
Total Resources	1,383	1,380	1,370	1,265	1,237	1,227	1,211	1,211
Load/Resources Balance	40	-1	-41	-179	-231	-367	-468	-600

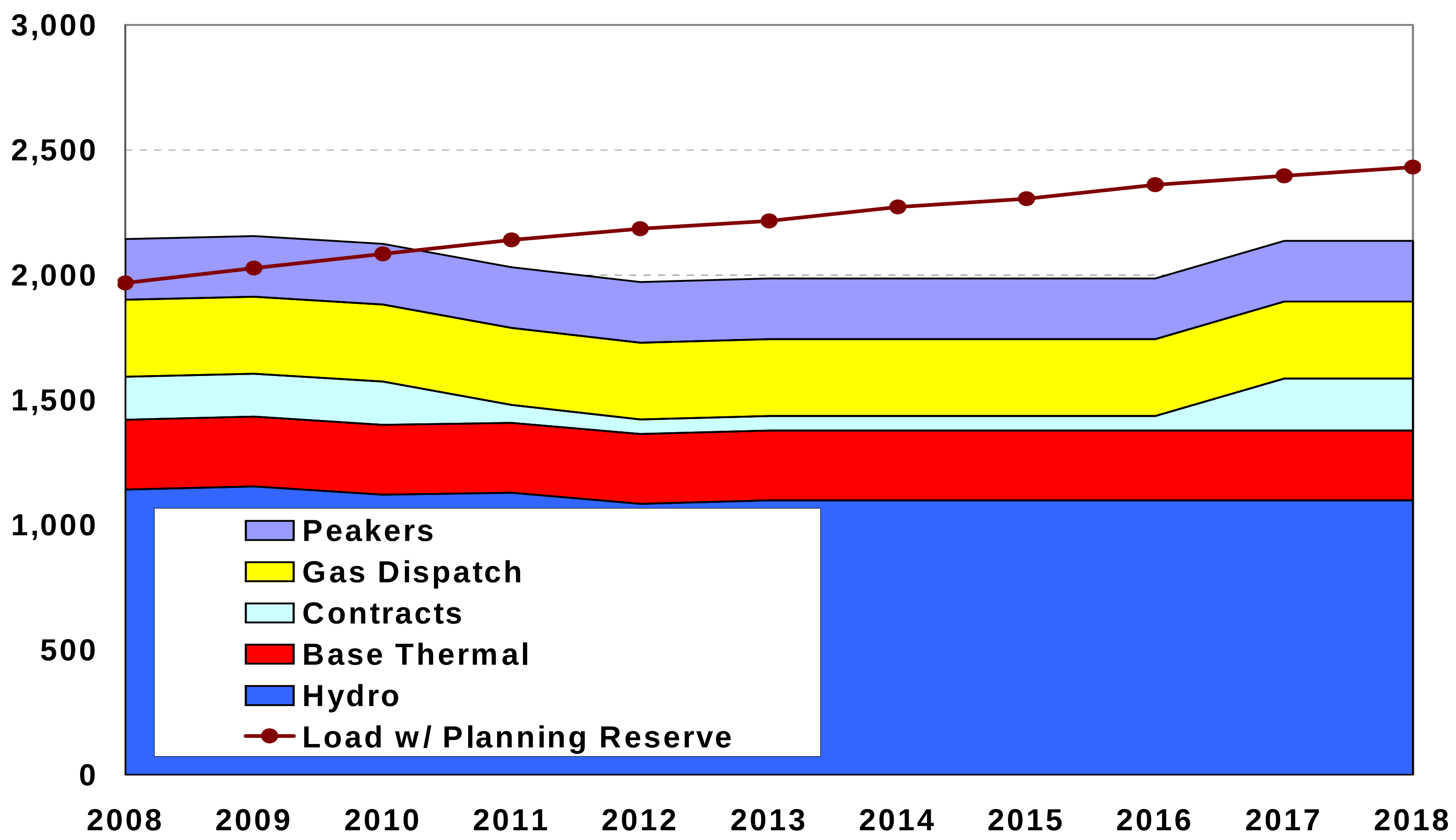
We answer to you.

Capacity Loads and Resources

	Last Updated August 14, 2006	Notes	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	PEAK LOAD AND RESOURCE PLANNING											
	REQUIREMENTS											
1	Native Load	1	(1,707)	(1,761)	(1,812)	(1,864)	(1,904)	(1,933)	(1,983)	(2,013)	(2,064)	(2,097)
2	Contracts Obligations	2	(169)	(169)	(168)	(168)	(166)	(165)	(165)	(165)	(165)	(15)
3	Total Requirements		(1,876)	(1,930)	(1,980)	(2,031)	(2,070)	(2,098)	(2,148)	(2,178)	(2,229)	(2,112)
	RESOURCES											
4	Contracts Rights	3	341	341	340	240	223	223	223	223	223	223
5	Hydro Resources	4	1,142	1,154	1,121	1,128	1,084	1,098	1,098	1,098	1,098	1,098
6	Base Load Thermals	5	280	280	280	280	280	280	280	280	280	280
7	Gas Dispatch Units	6	308	308	308	308	308	308	308	308	308	308
8	Peaking Units	7	243	243	243	243	243	243	243	243	243	243
9	Total Resources		2,312	2,324	2,292	2,199	2,137	2,151	2,151	2,151	2,151	2,151
10	**PEAK POSITION**		**436**	**395**	**312**	**167**	**67**	**53**	**3**	**(27)**	**(78)**	**39**
	RESERVE PLANNING											
11	Planning Reserve Margin	8	(261)	(266)	(271)	(276)	(280)	(283)	(288)	(291)	(296)	(300)
12	**RESERVE PEAK POSITION**		**176**	**129**	**40**	**(109)**	**(213)**	**(230)**	**(285)**	**(318)**	**(375)**	**(260)**

We answer to you.

Capacity L&R – Annual Resource Capability



We answer to you. AVISTA

Capacity L&R – Annual Resource Capability

	2008	2009	2010	2011	2012	2017	2022	2027
Load w/ Planning Reserve	1,968	2,027	2,084	2,140	2,185	2,361	2,600	2,822
Contracts	172	172	173	73	58	58	128	128
Hydro	1,142	1,154	1,121	1,128	1,084	1,098	1,056	1,070
Base Thermal	280	280	280	280	280	280	280	280
Gas Dispatch	308	308	308	308	308	308	308	308
Peakers	243	243	243	243	243	243	243	243
Total Resources	2,144	2,156	2,124	2,031	1,972	1,986	2,014	2,028
Loads/Resources Balance	176	129	40	-109	-213	-375	-586	-794

We answer to you.

Adjustments

- L&R adjustments from 2005 IRP:
  - Load forecast – updated in July
  - Confidence interval updated
  - Hydro upgrades
  - Updated contracts (small power, wind, Upriver)
  - Added Thompson River Co-Gen project
  - Hydro forecast changed, going from a 60-year historical model to a 70-year historical model

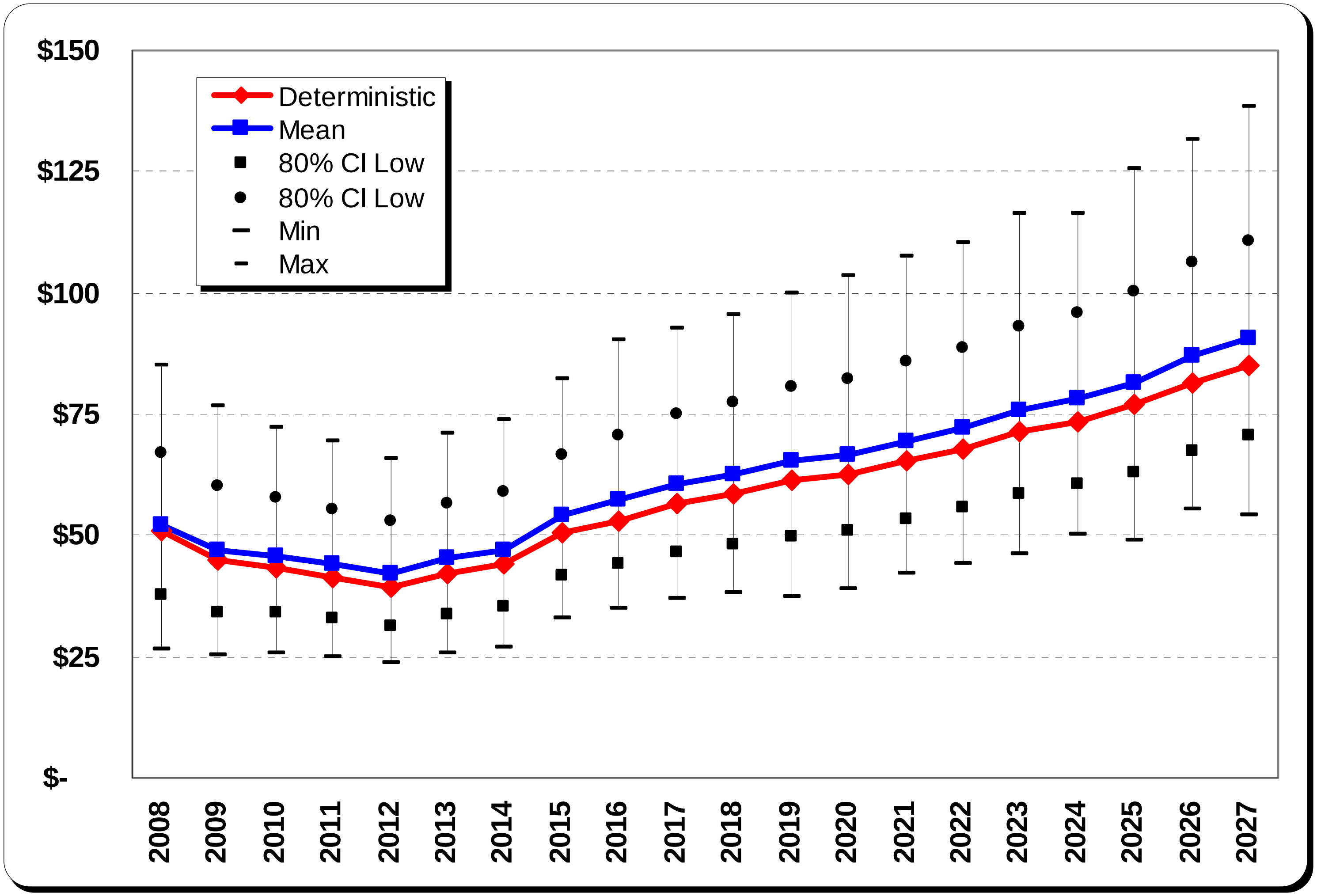
We answer to you.

Fundamental Modeling
Futures and Scenarios

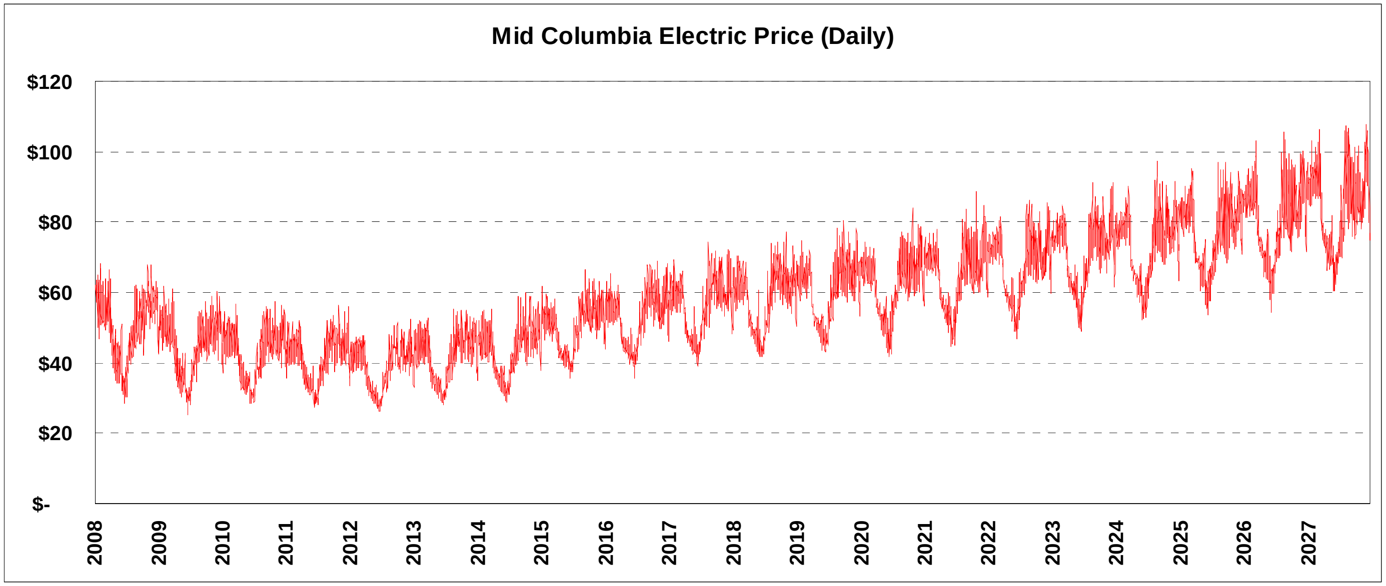
2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

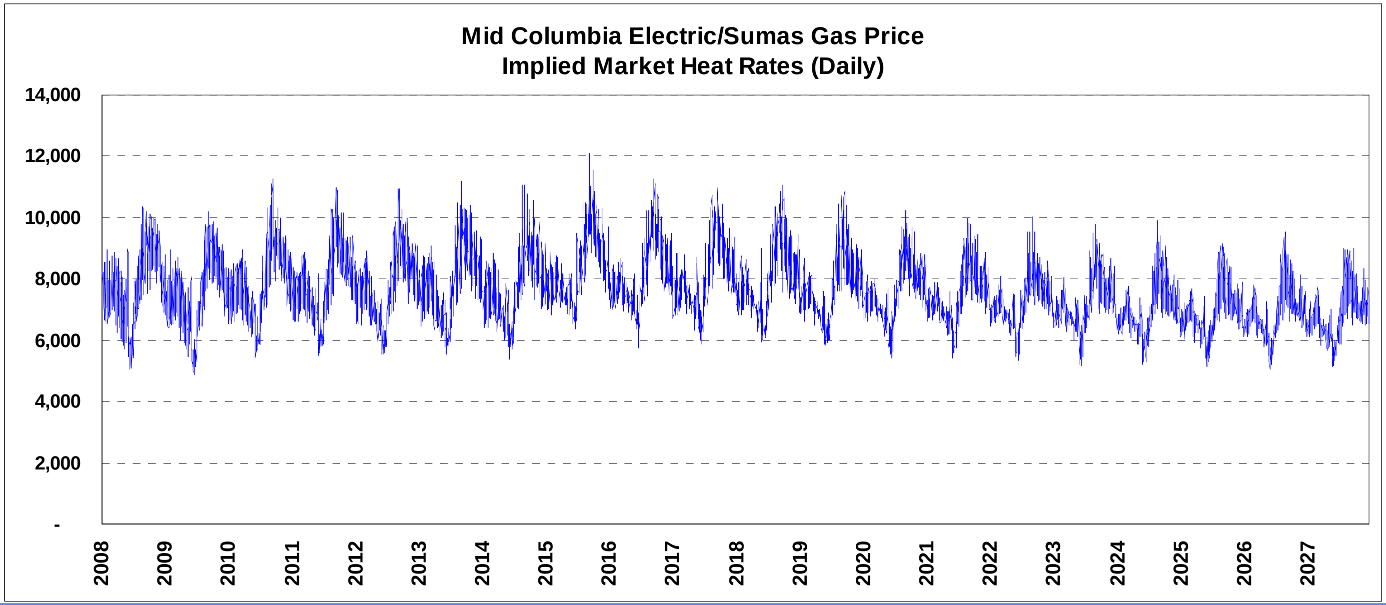
James Gall

Base Case: Mid-C Annual Average Prices



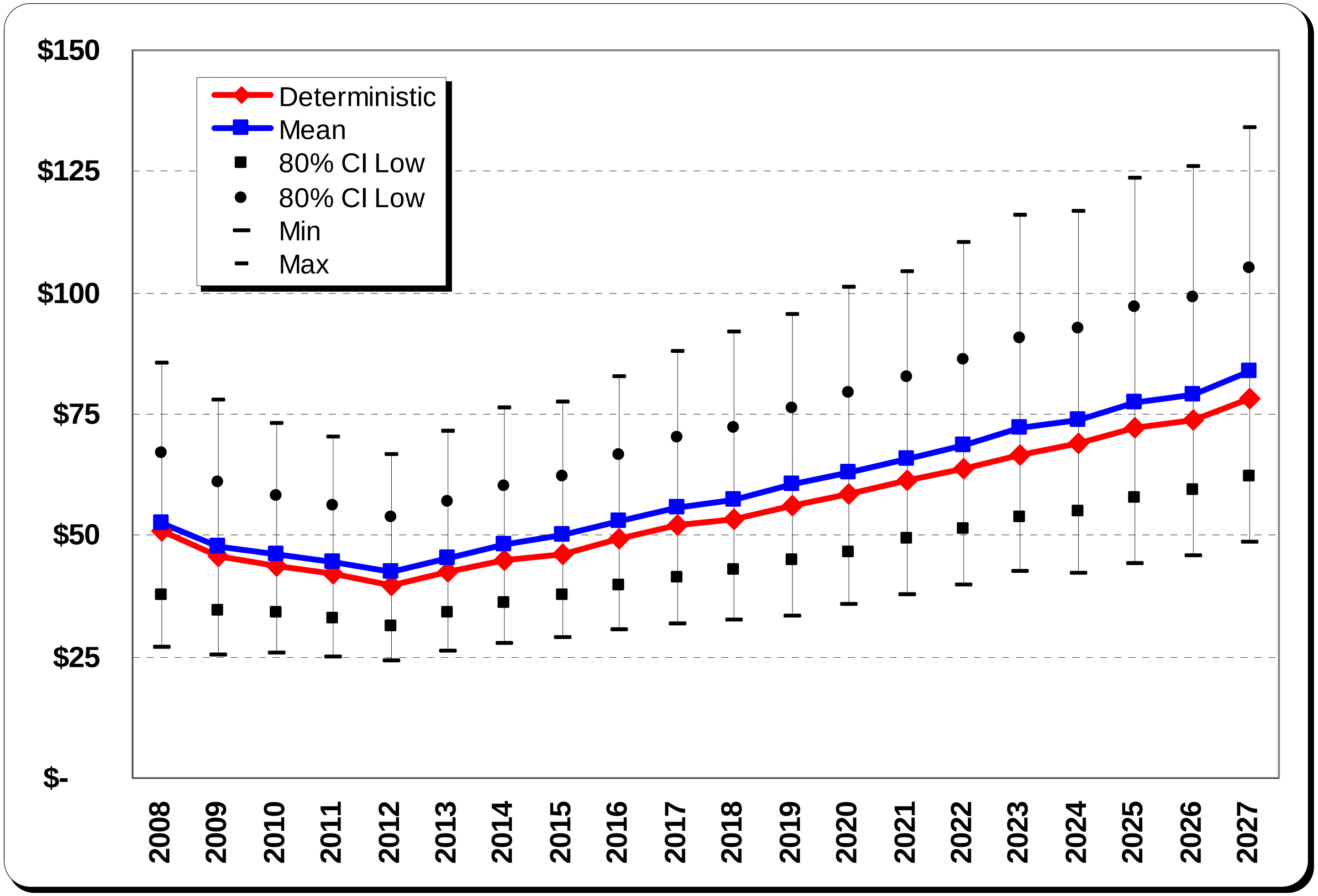
We answer to you.





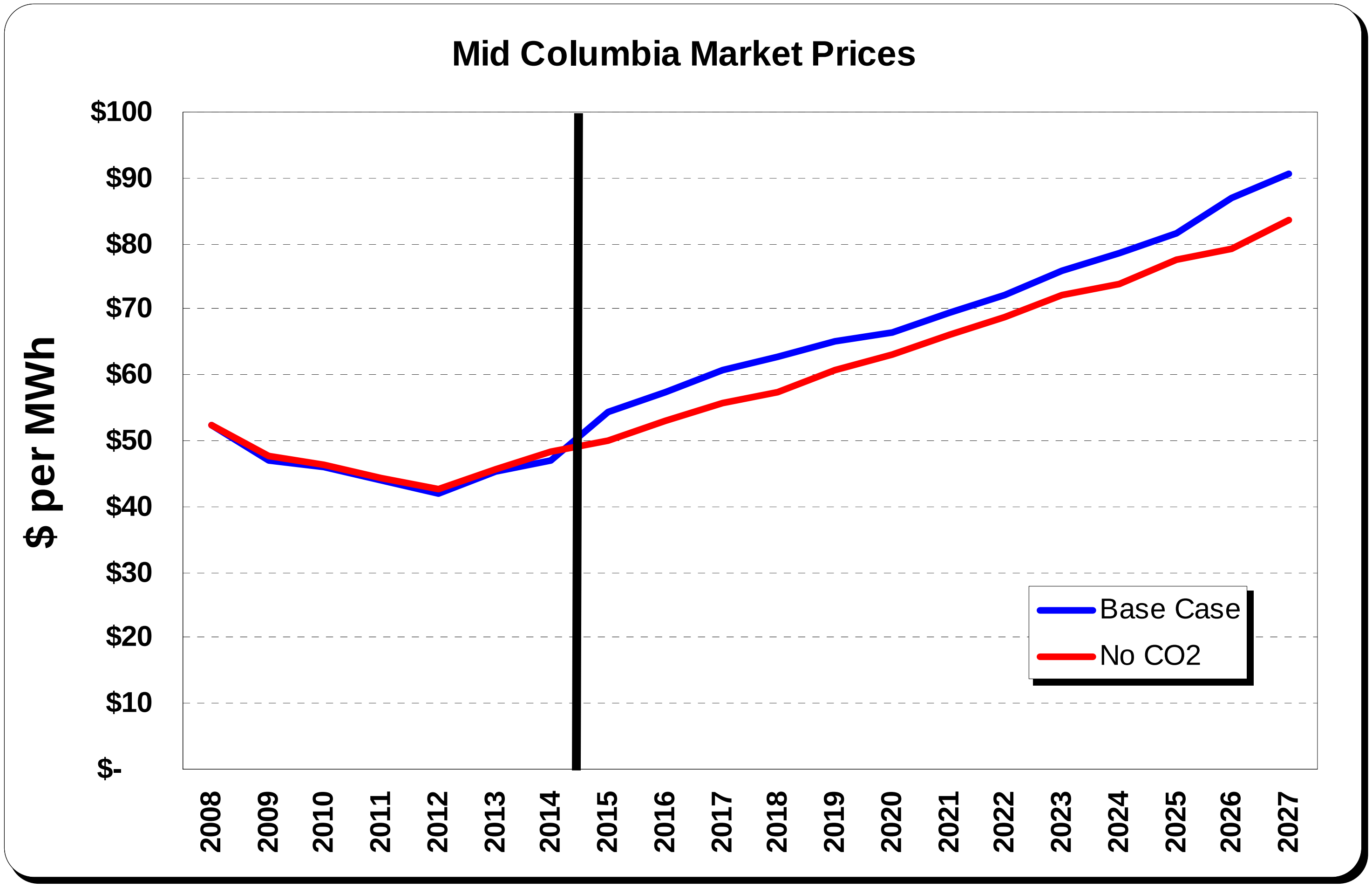
We answer to you.

No CO_2 Tax Future: Mid-C Annual Average Prices



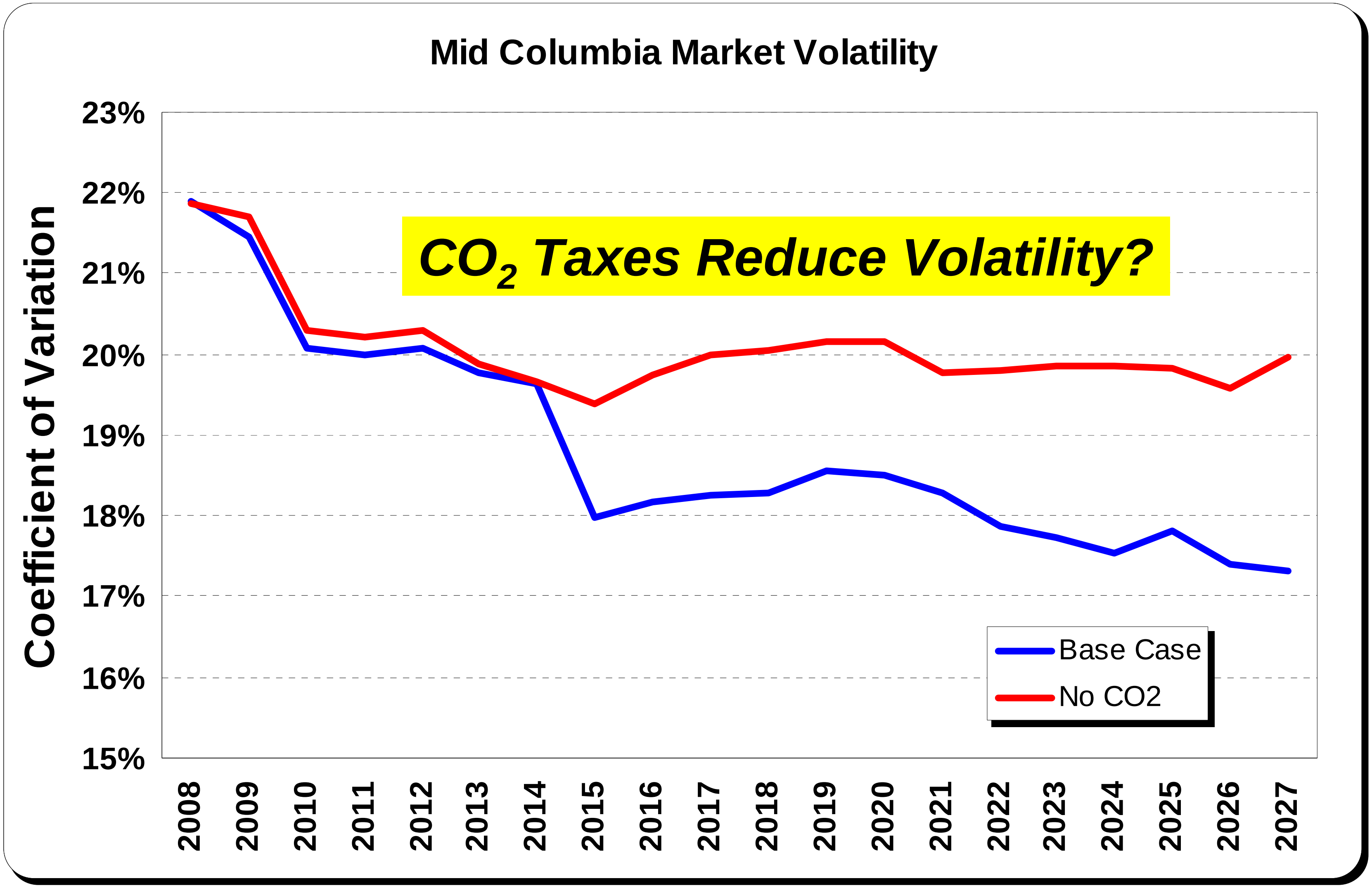
We answer to you. AVISTA

Cost of CO_2 Taxation to Market (~$4.50)



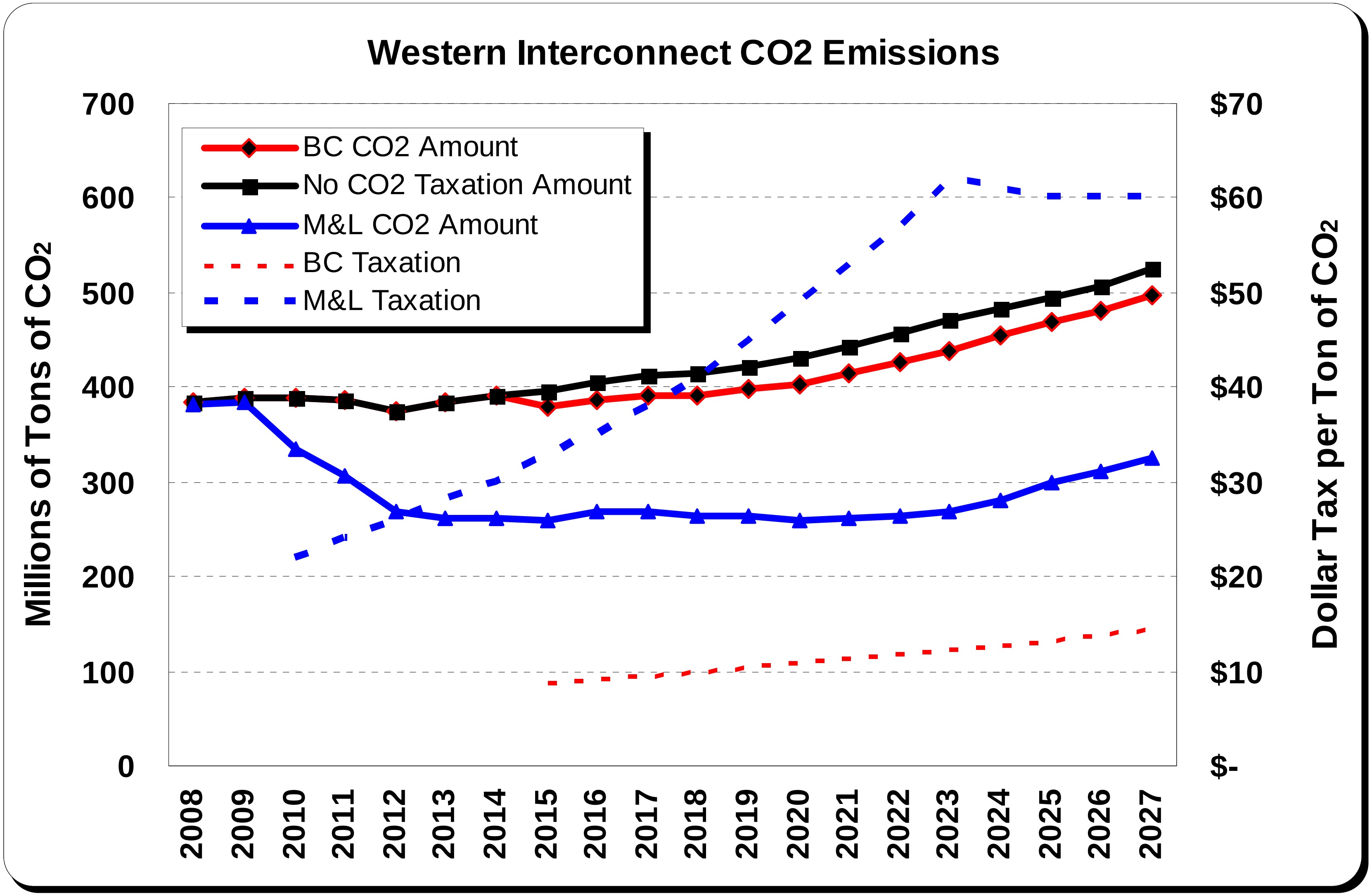
We answer to you.

AVISTA



We answer to you.

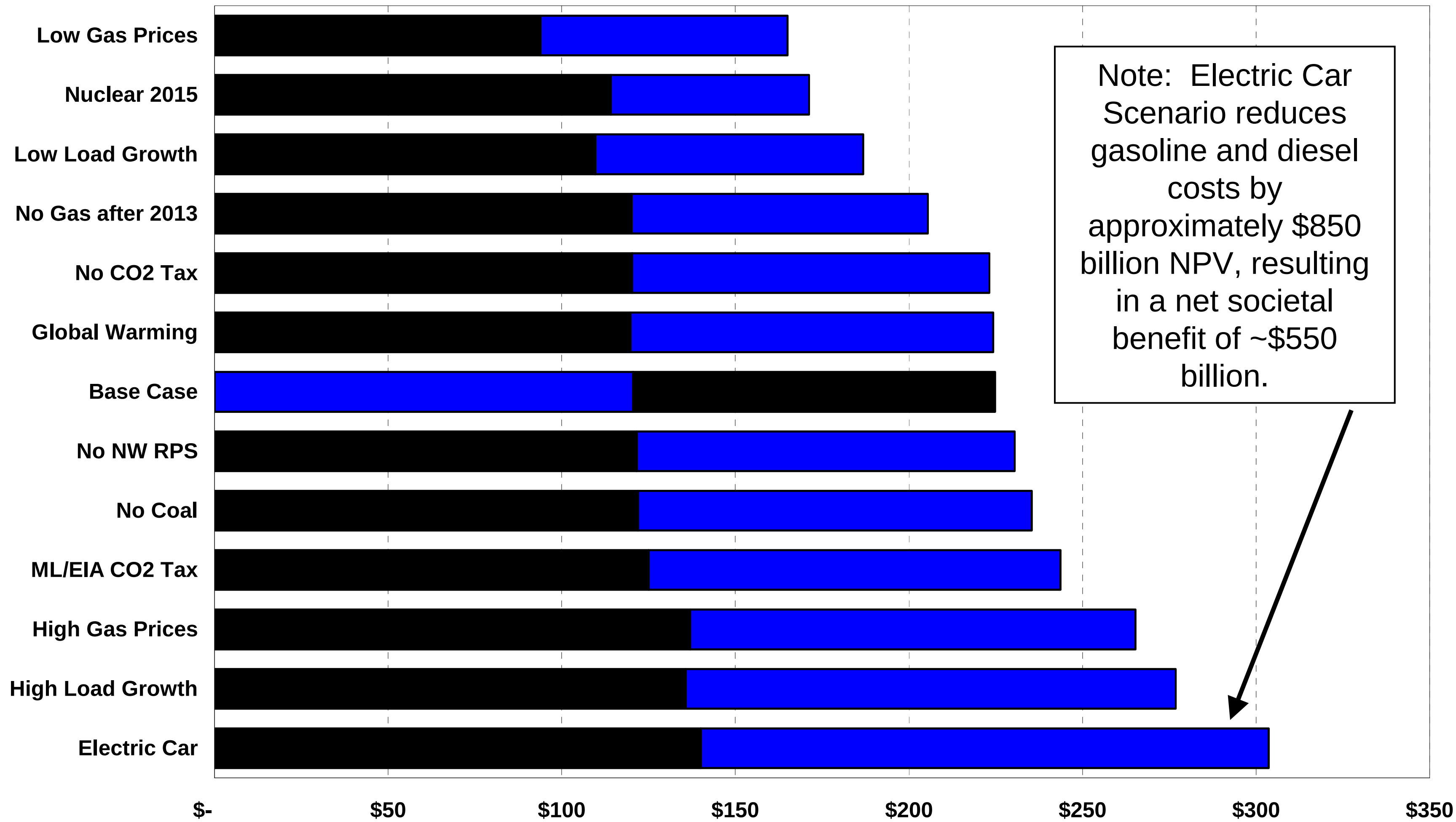
AVISTA



We answer to you.

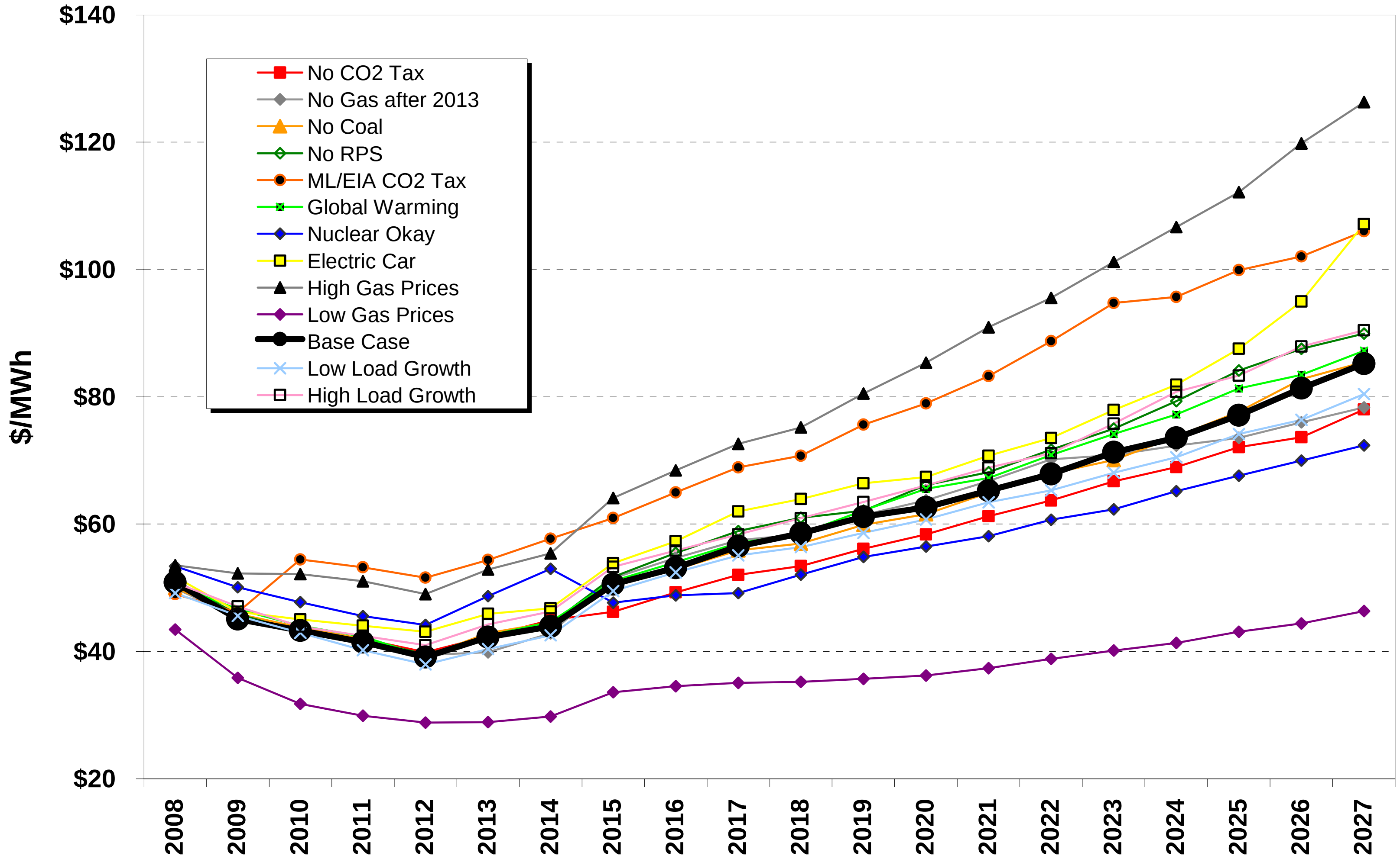
Western Interconnect Total Fuel Cost in Billions

(Does Not Include Emission Taxes)



We answer to you.

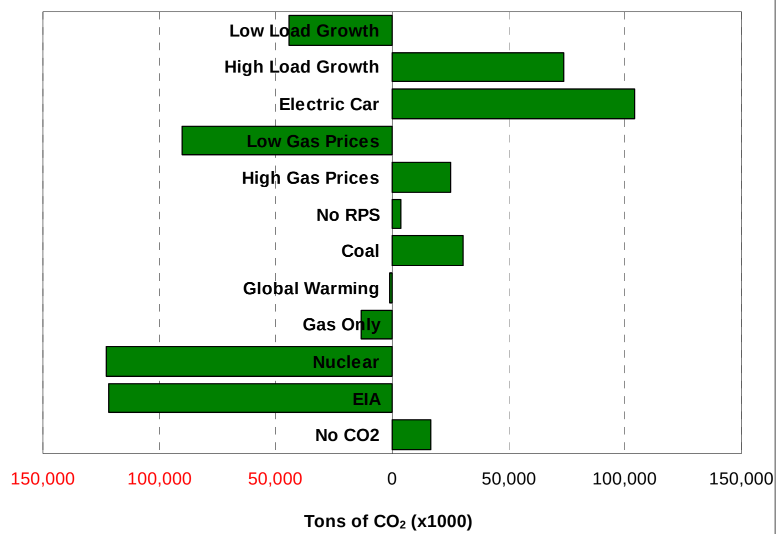
Mid C Electric Prices For All Studies



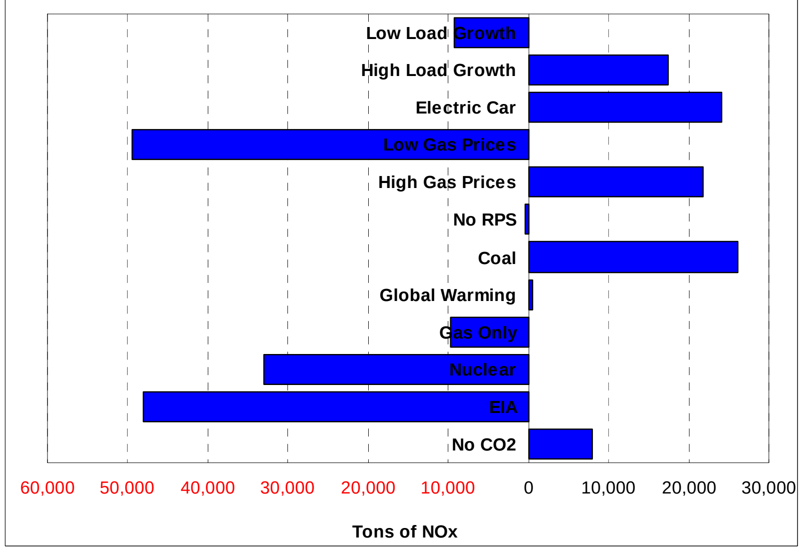
We answer to you.

Electric Car Scenario does not include offsets from reduced gasoline/diesel consumption

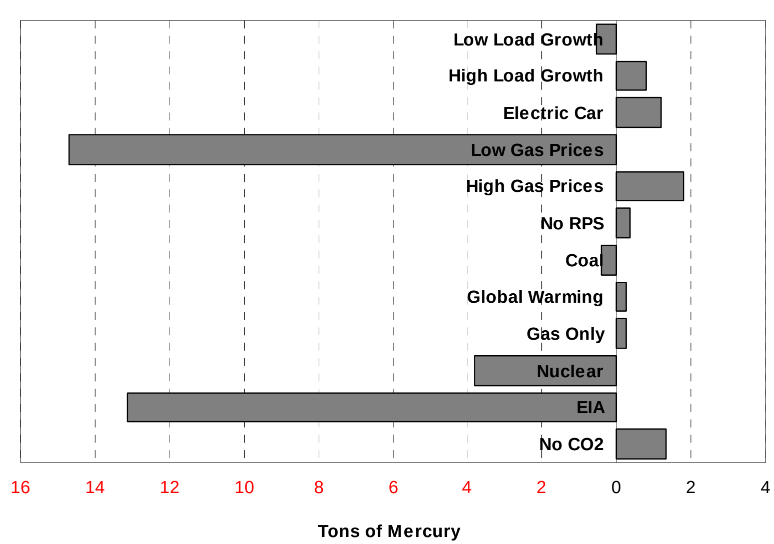
Change in CO_2 Emissions from Base Case (Avg Annual)



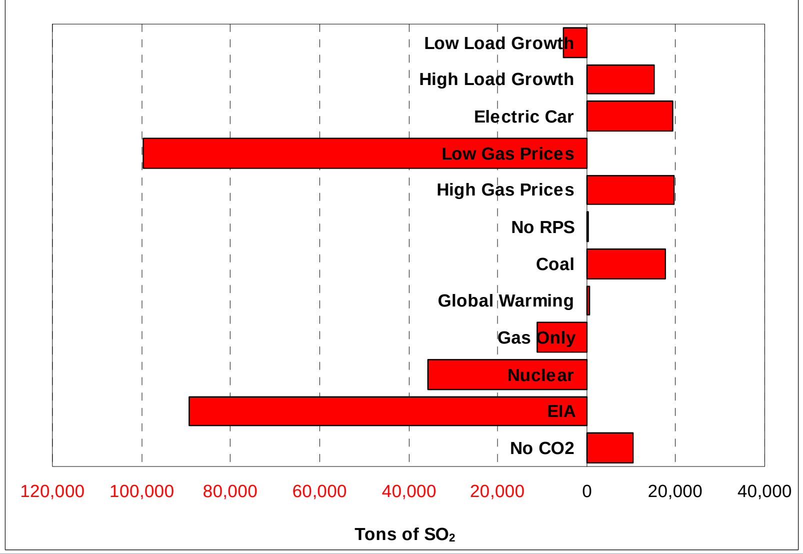
Change in NOx Emissions from Base Case (Avg Annual)



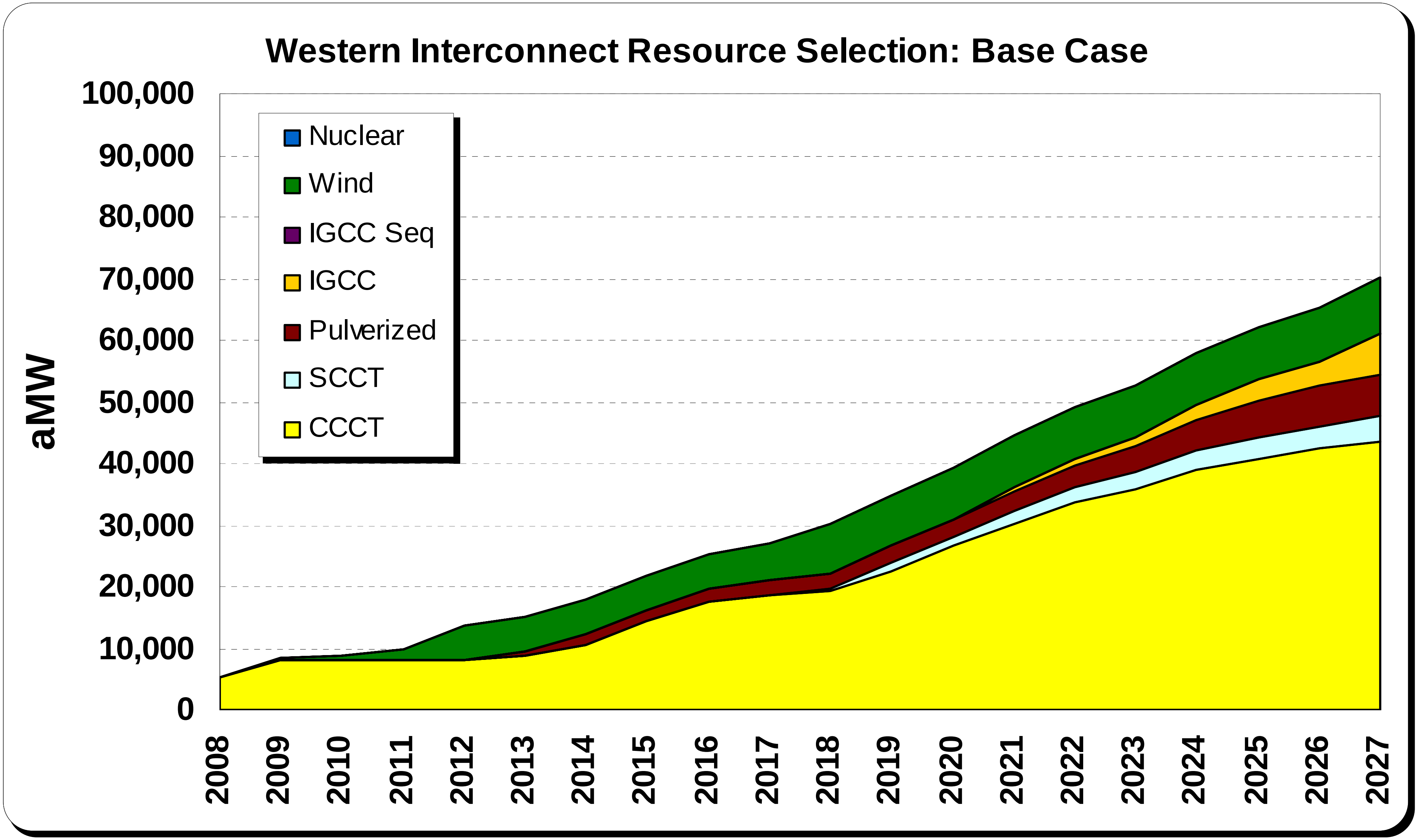
Change in Hg Emissions from Base Case (Avg Annual)

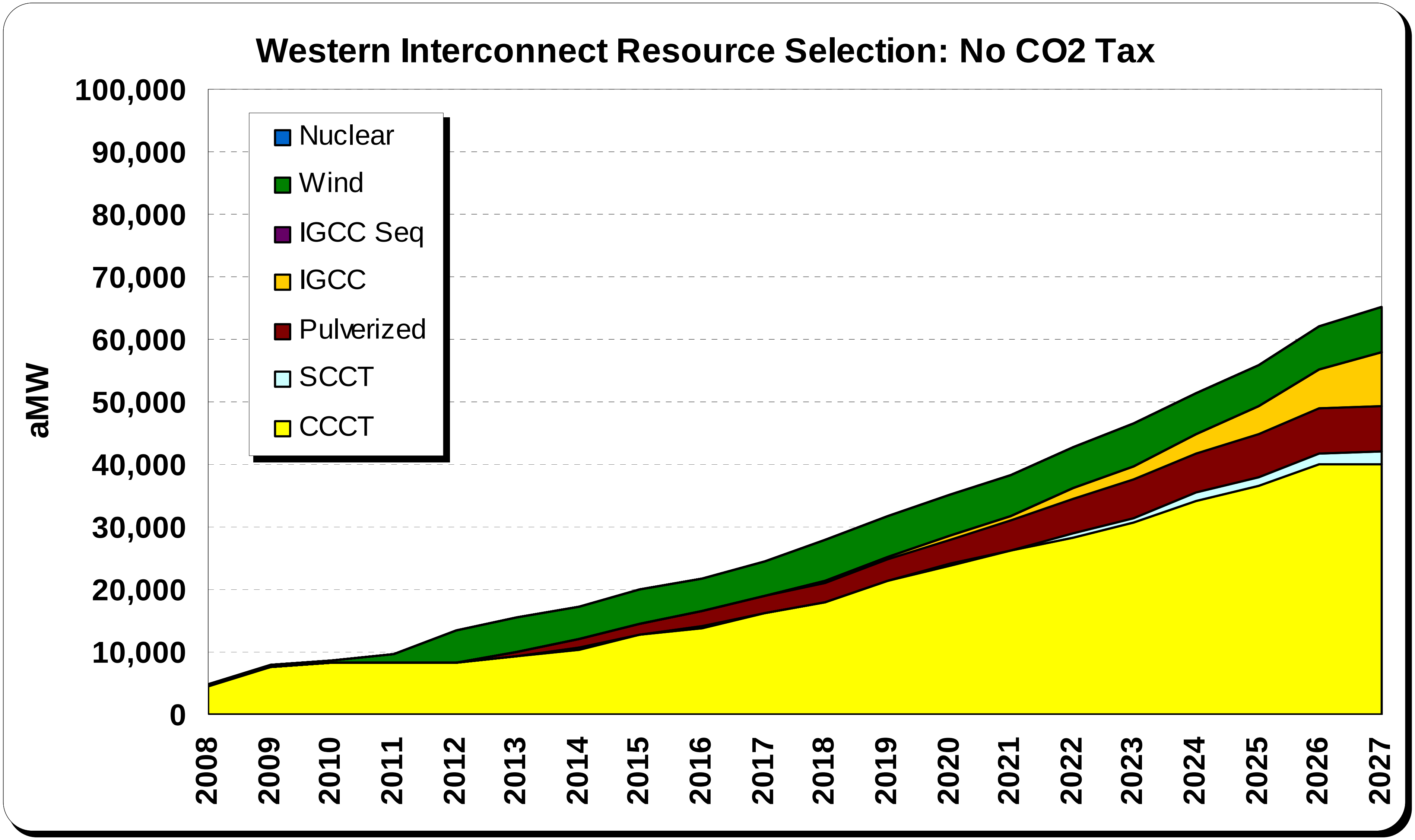


Change in SO_2 Emissions from Base Case (Avg Annual)

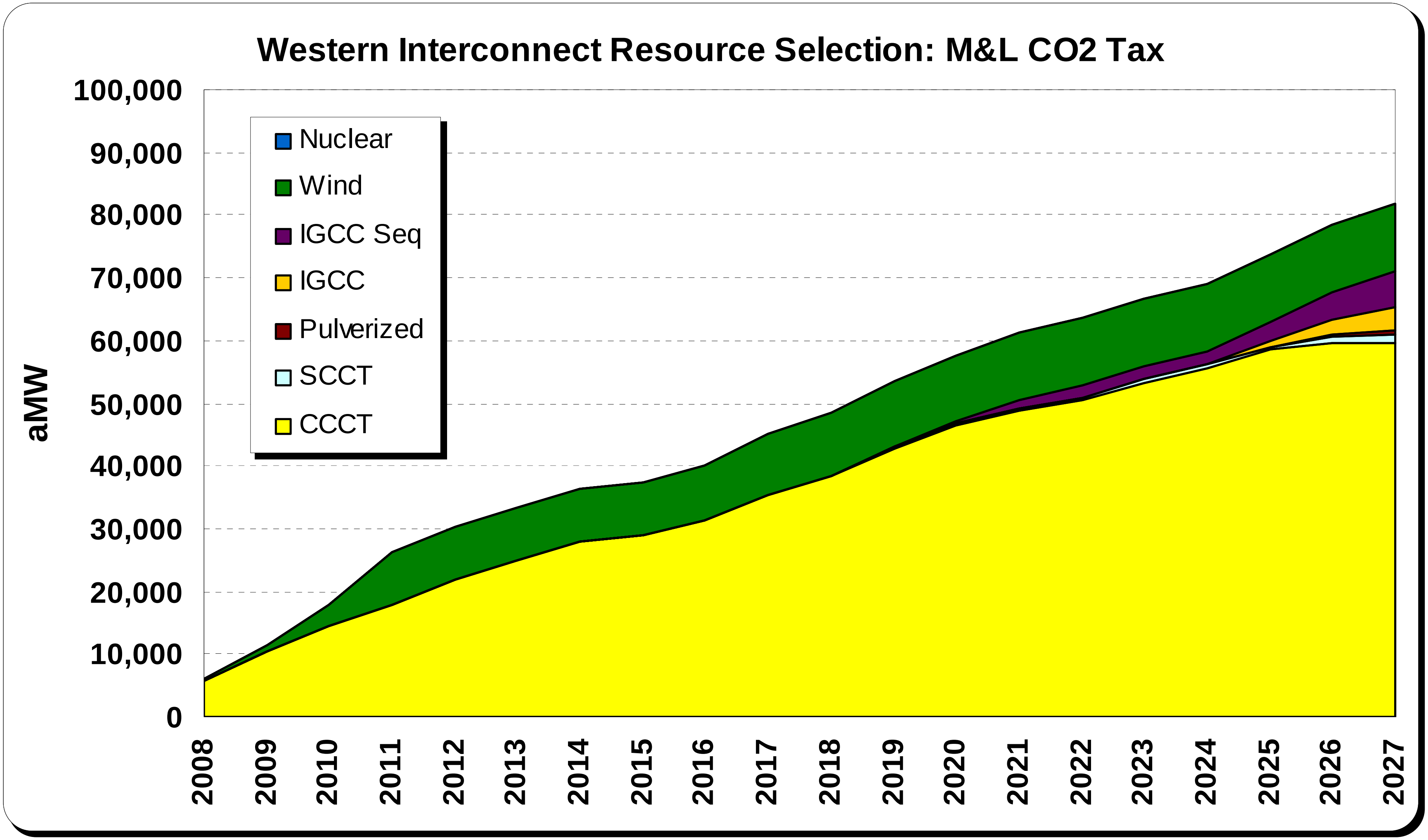


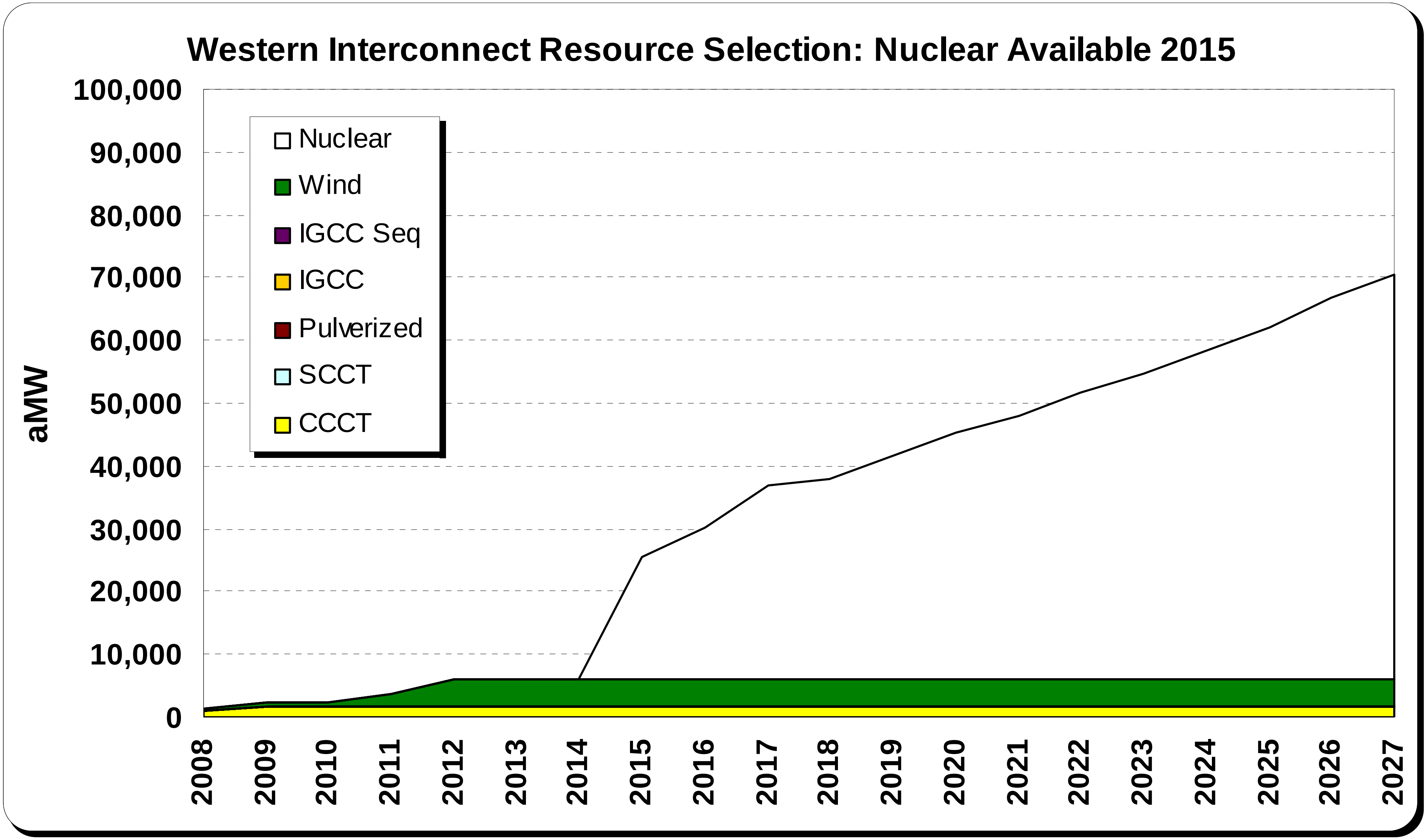
We answer to you.




Western Interconnect Resource Selection: No CO2 Tax
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
aMW
Nuclear
Wind
IGCC Seq
IGCC
Pulverized
SCCT
CCCT
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027

We answer to you.

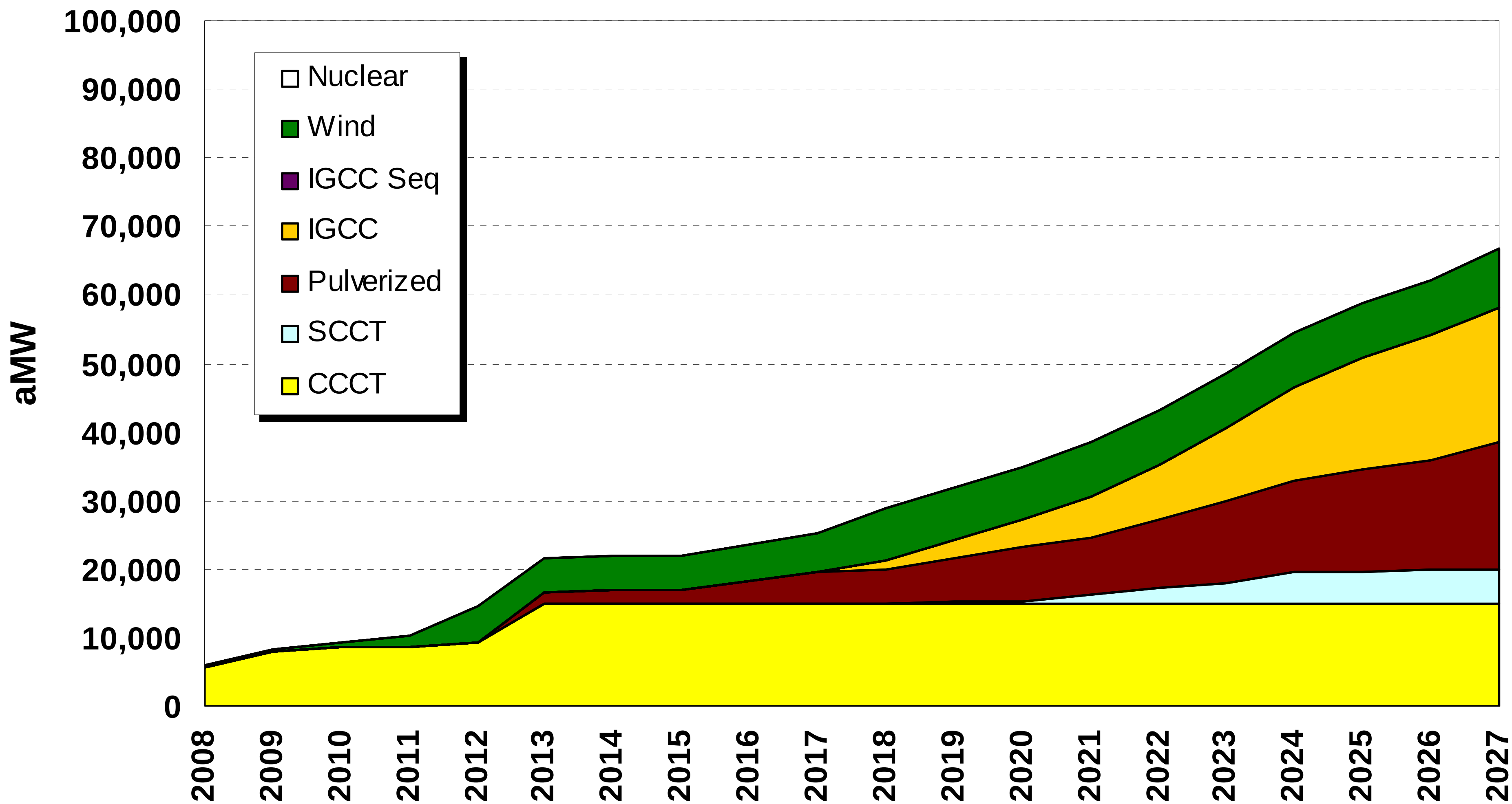



Western Interconnect Resource Selection: Nuclear Available 2015
aMW
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Nuclear
Wind
IGCC Seq
IGCC
Pulverized
SCCT
CCCT
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027

We answer to you.

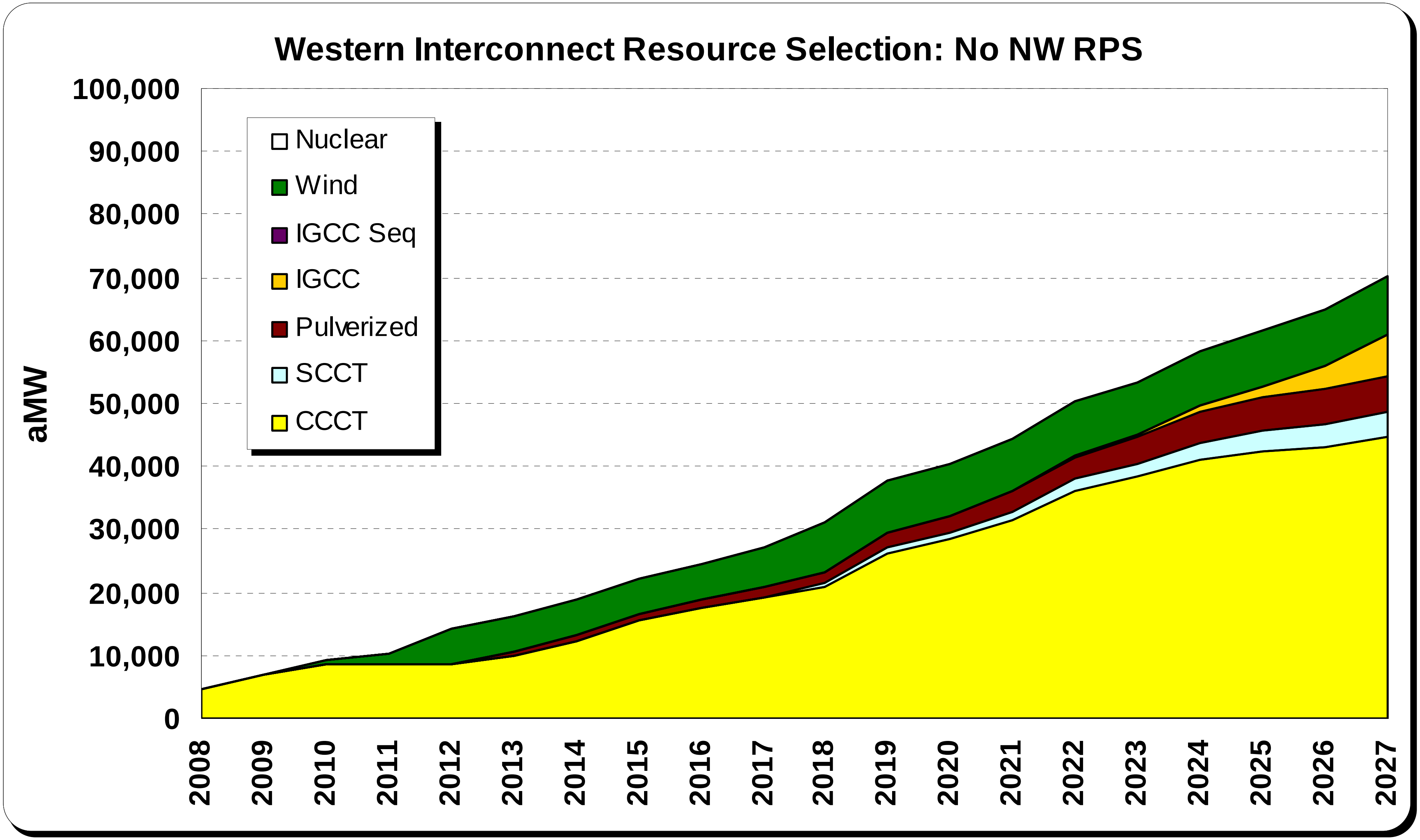
AVISTA

Western Interconnect Resource Selection: No Gas Build after 2013



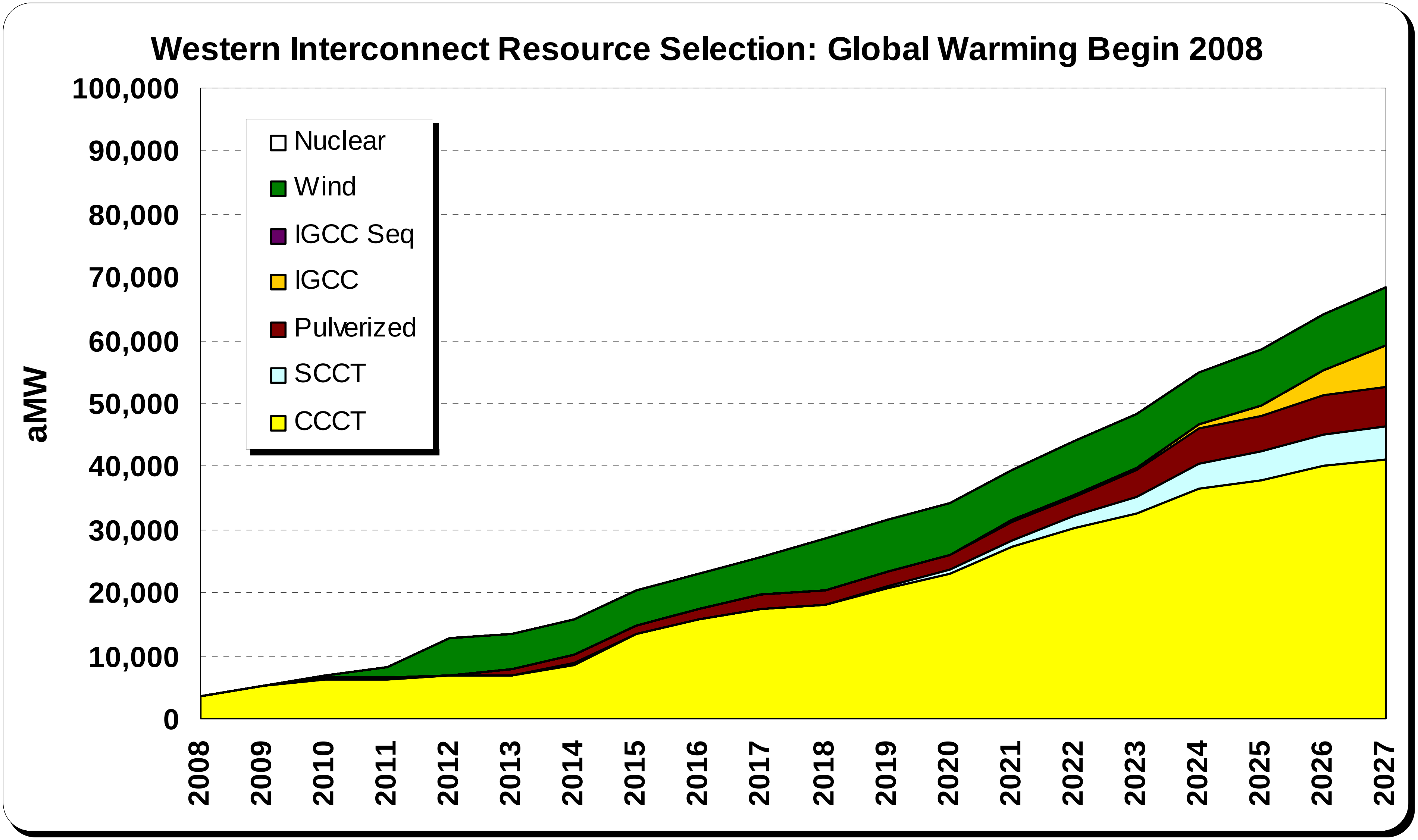
We answer to you.

AVISTA



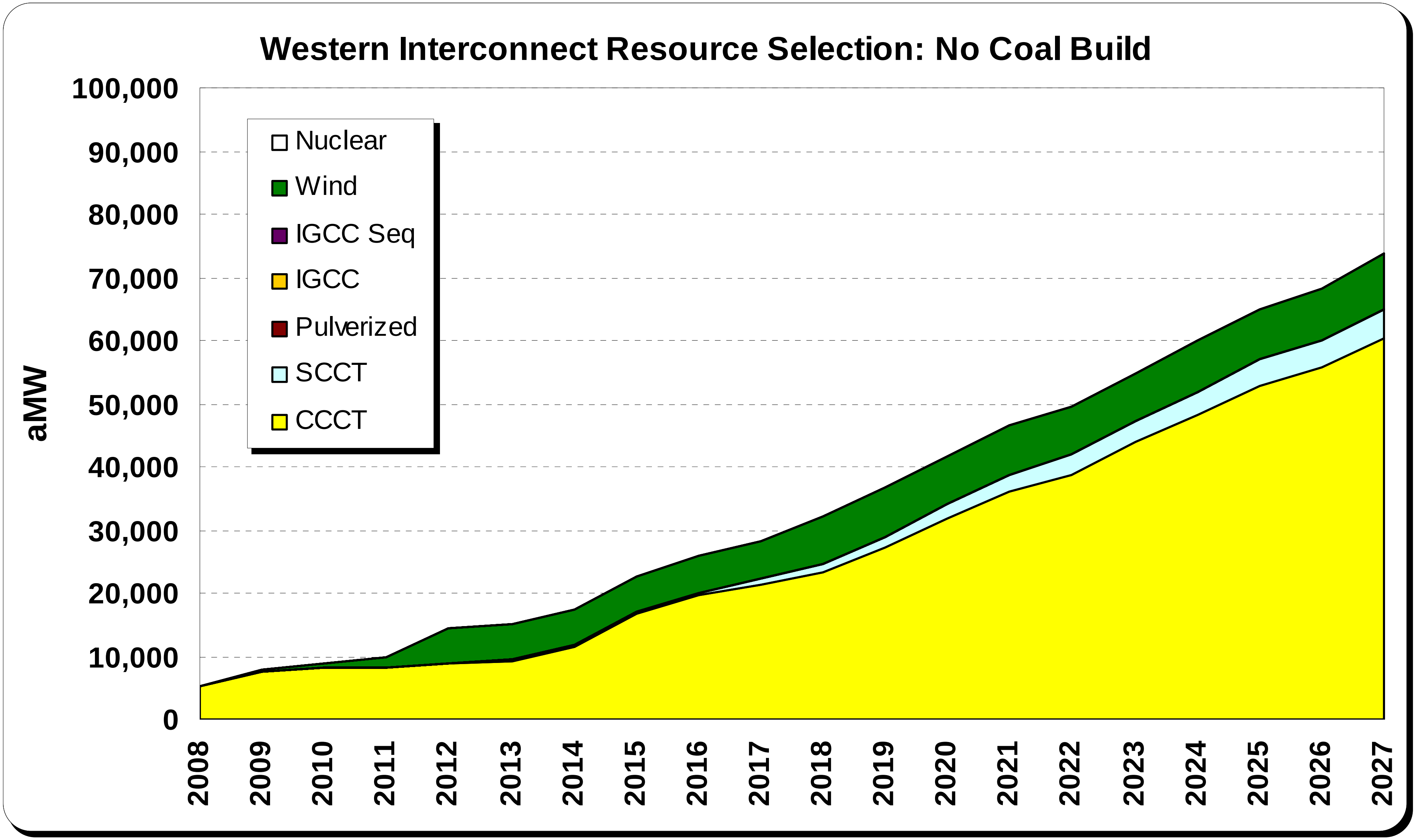
We answer to you.

AVISTA



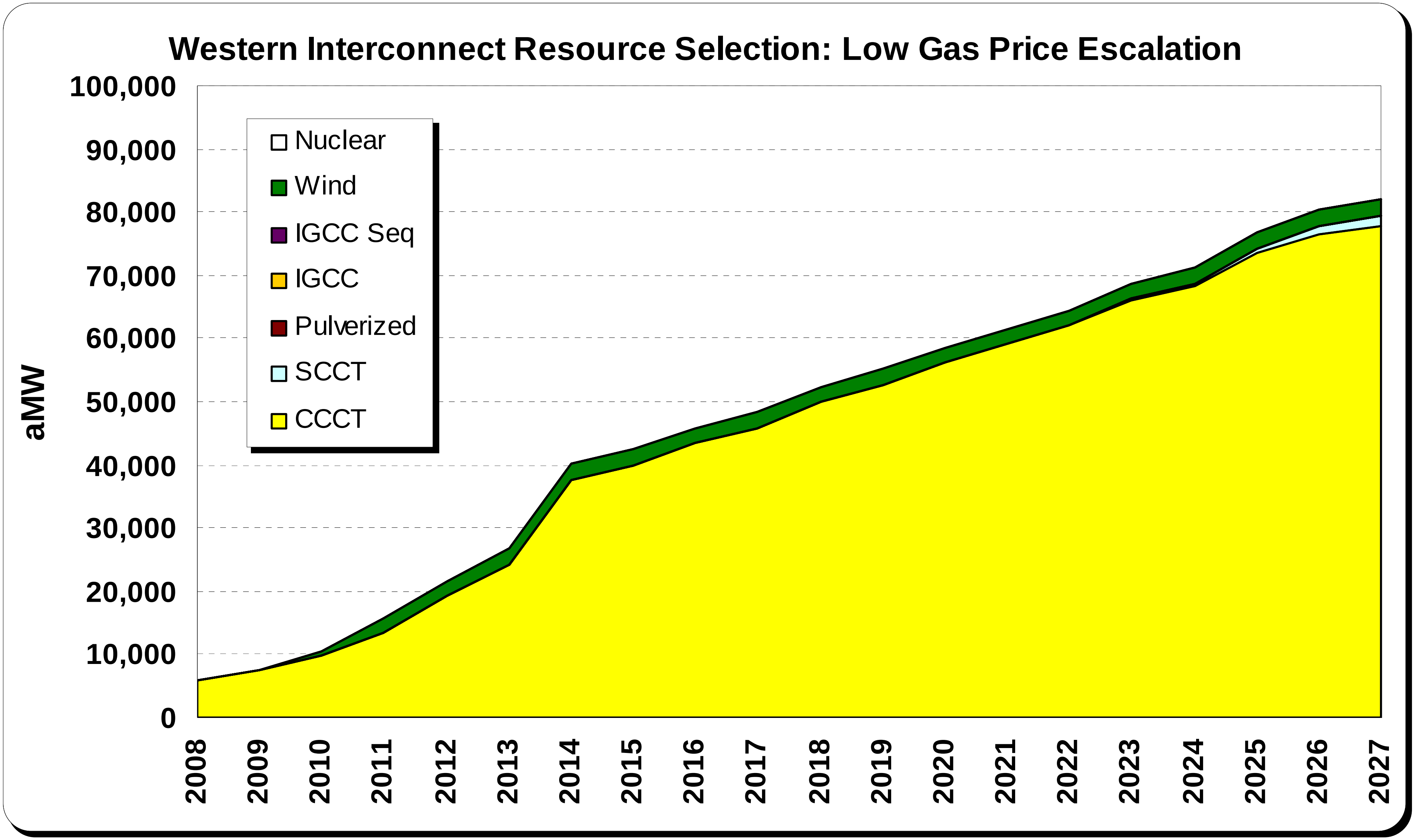
We answer to you.

AVISTA



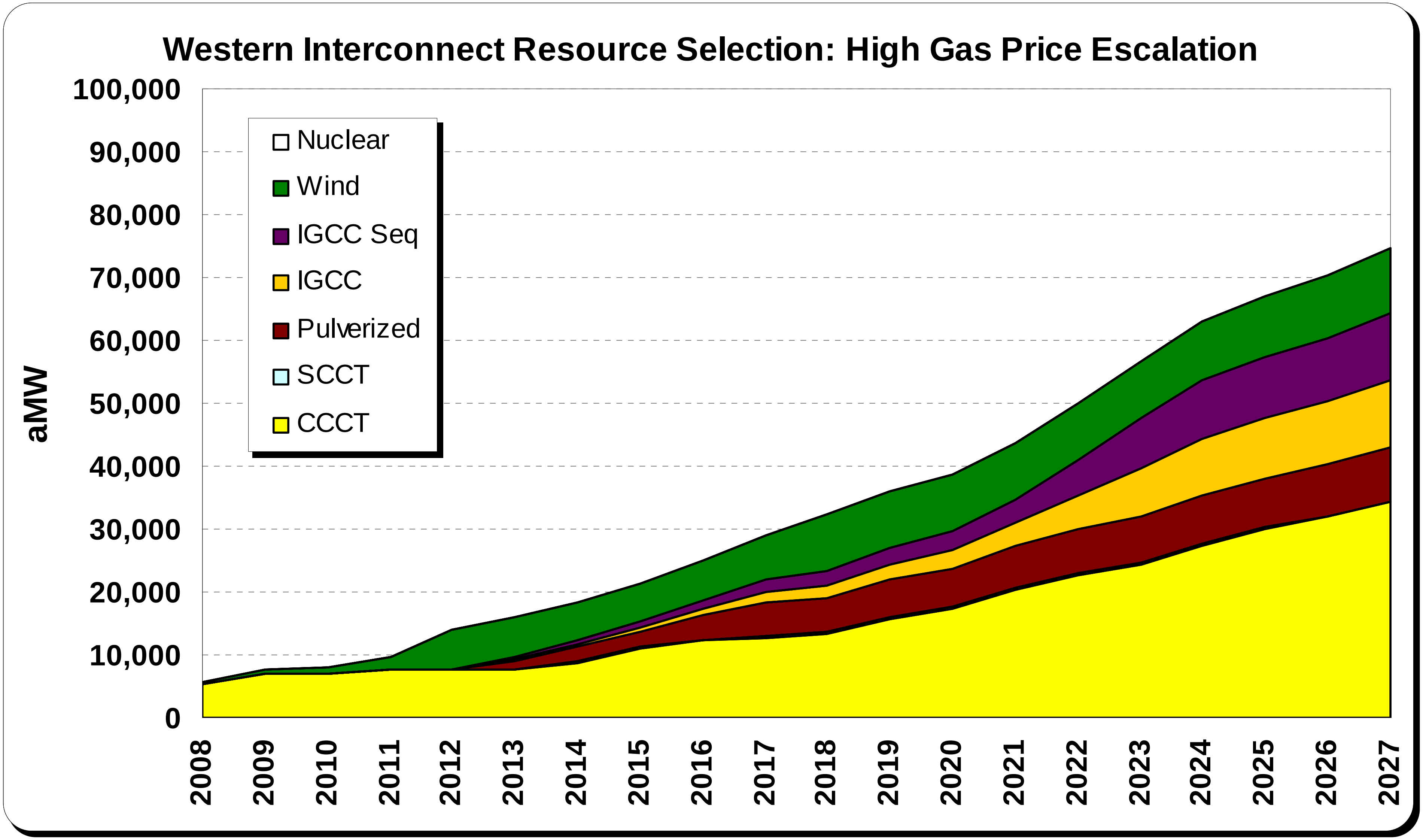
We answer to you.

AVISTA

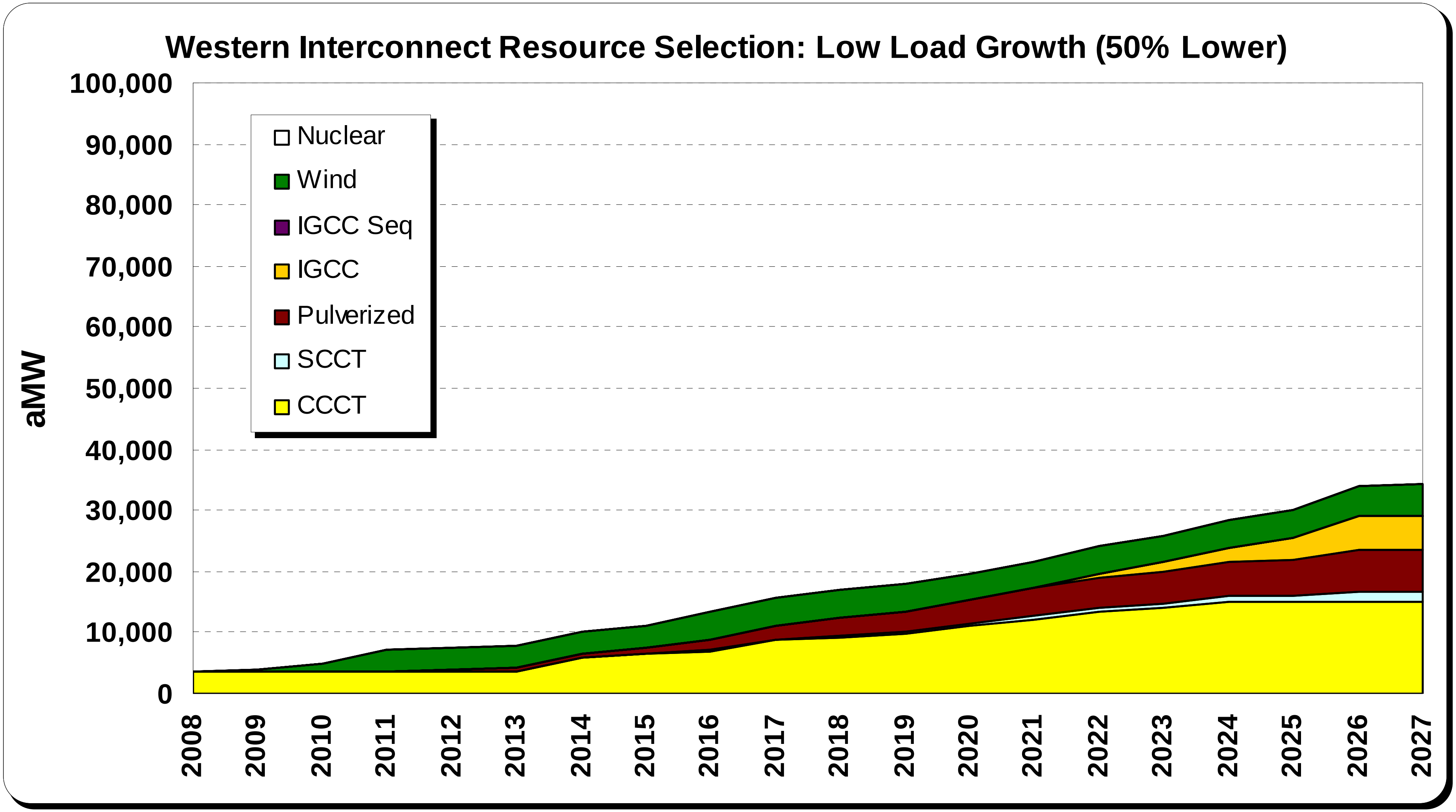


We answer to you.

AVISTA

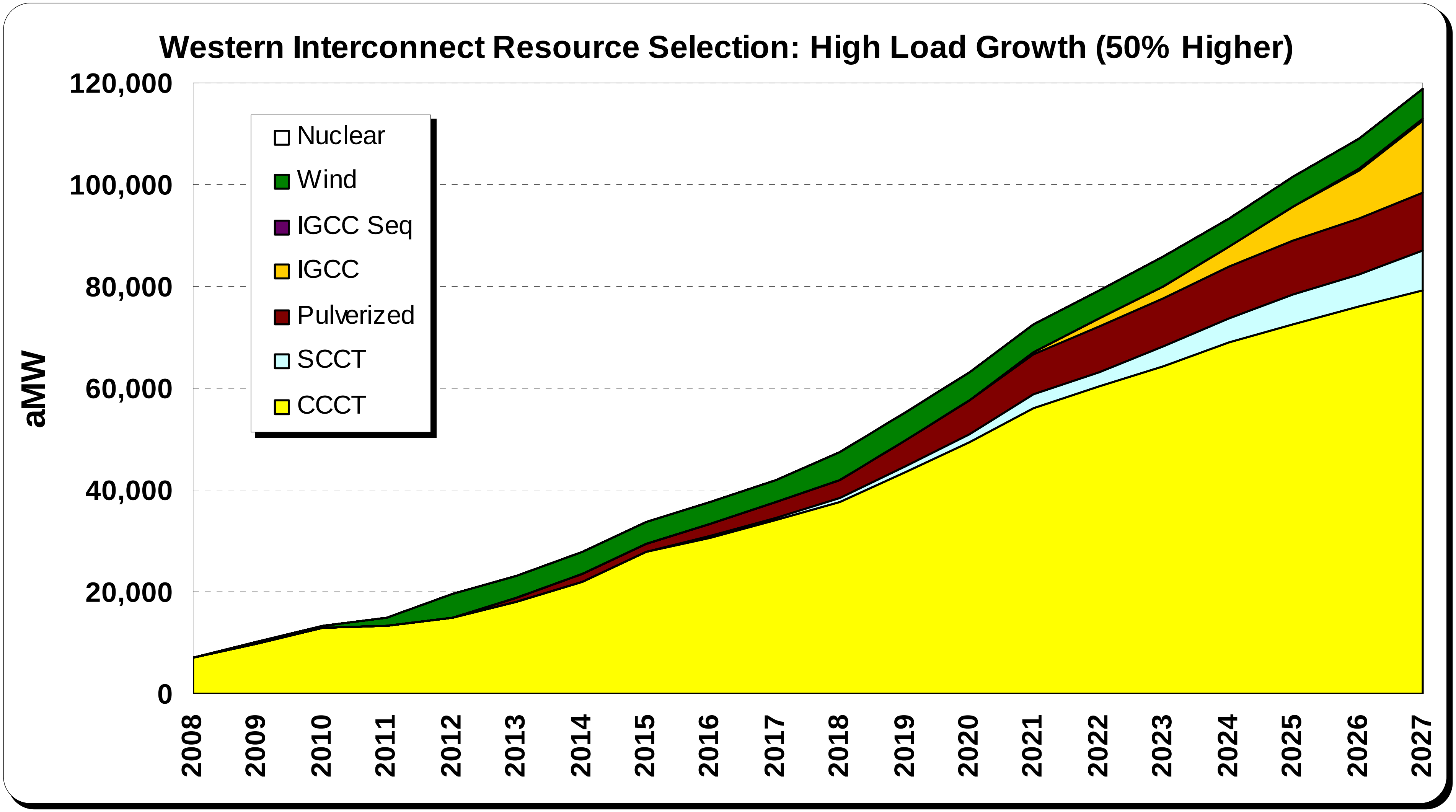


We answer to you.

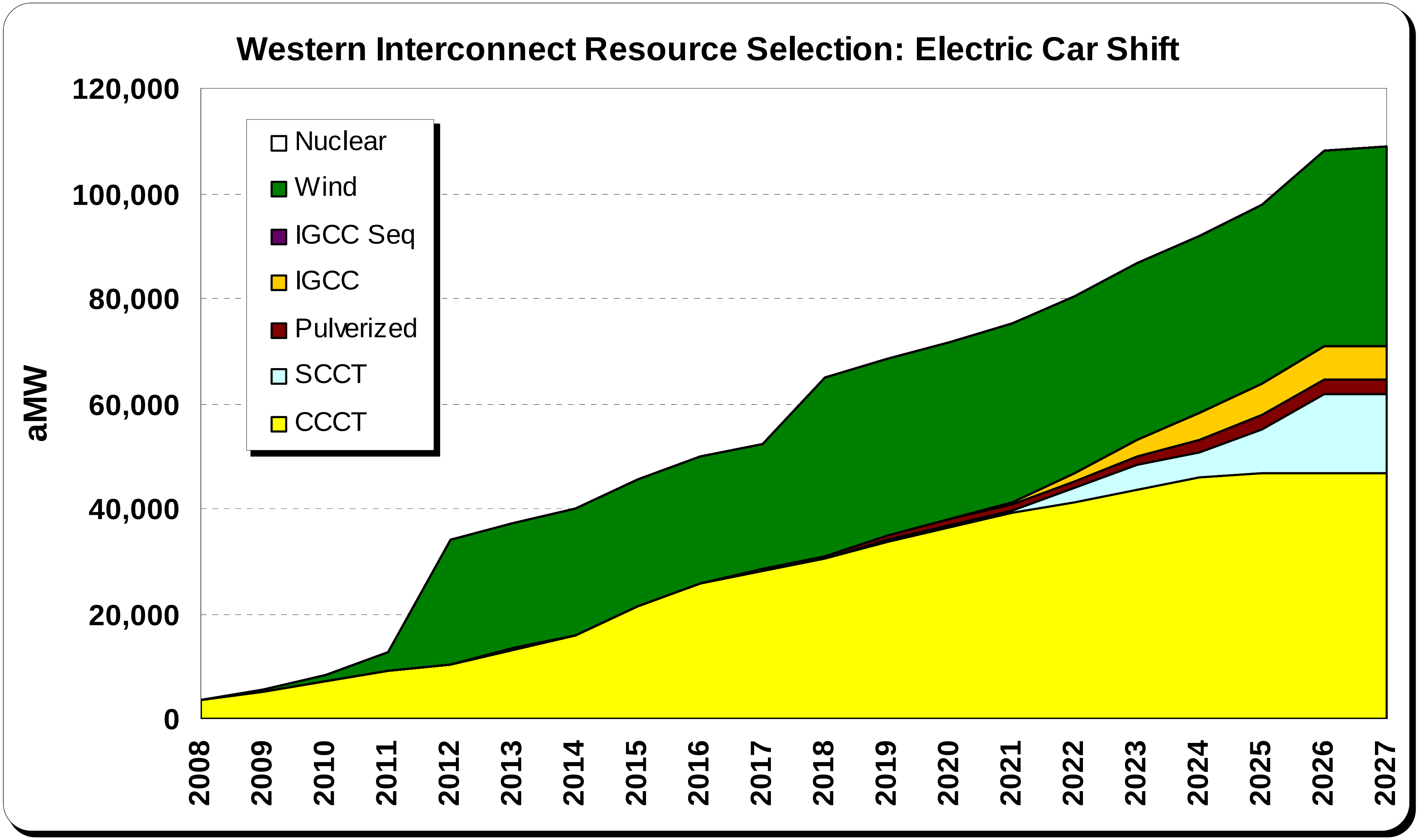


We answer to you.

AVISTA



We answer to you.



We answer to you.

Preliminary PRS Discussion

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
September 1, 2006

James Gall & Clint Kalich

We answer to you.

Prior Preferred Resource Strategies

Time Period	Resource Type	2005 IRP	2003 IRP
2007-2016	Coal	215	325
	Wind	122	30
	Gas	0	200
	Other Renewables	57	0
	Conservation and Plant Upgrades	69	46
2007-2026	Coal	474	775
	Wind	188	30
	Gas	0	200
	Other Renewables	137	0
	Conservation and Plant Upgrades	138	92

We answer to you.

Preferred Resource Strategy (PRS) Model

- Linear program that optimizes cost and risk of Avista's current electric portfolio of resources with potential resources to meet the Company's expected load growth
- Developed internally by Avista using MS Excel and an Add-in What's Best® to perform the solving function
- Mark to market resource values from AURORA are uploaded into the model for each potential resource and for all 300 iterations
- The model's objective function is to optimize net position deficits given resource constraints such as availability, time to construct, G & T capital costs, fixed and variable O&M, emissions, renewable certificates, tax credits, other transmission costs, market value and fuel costs

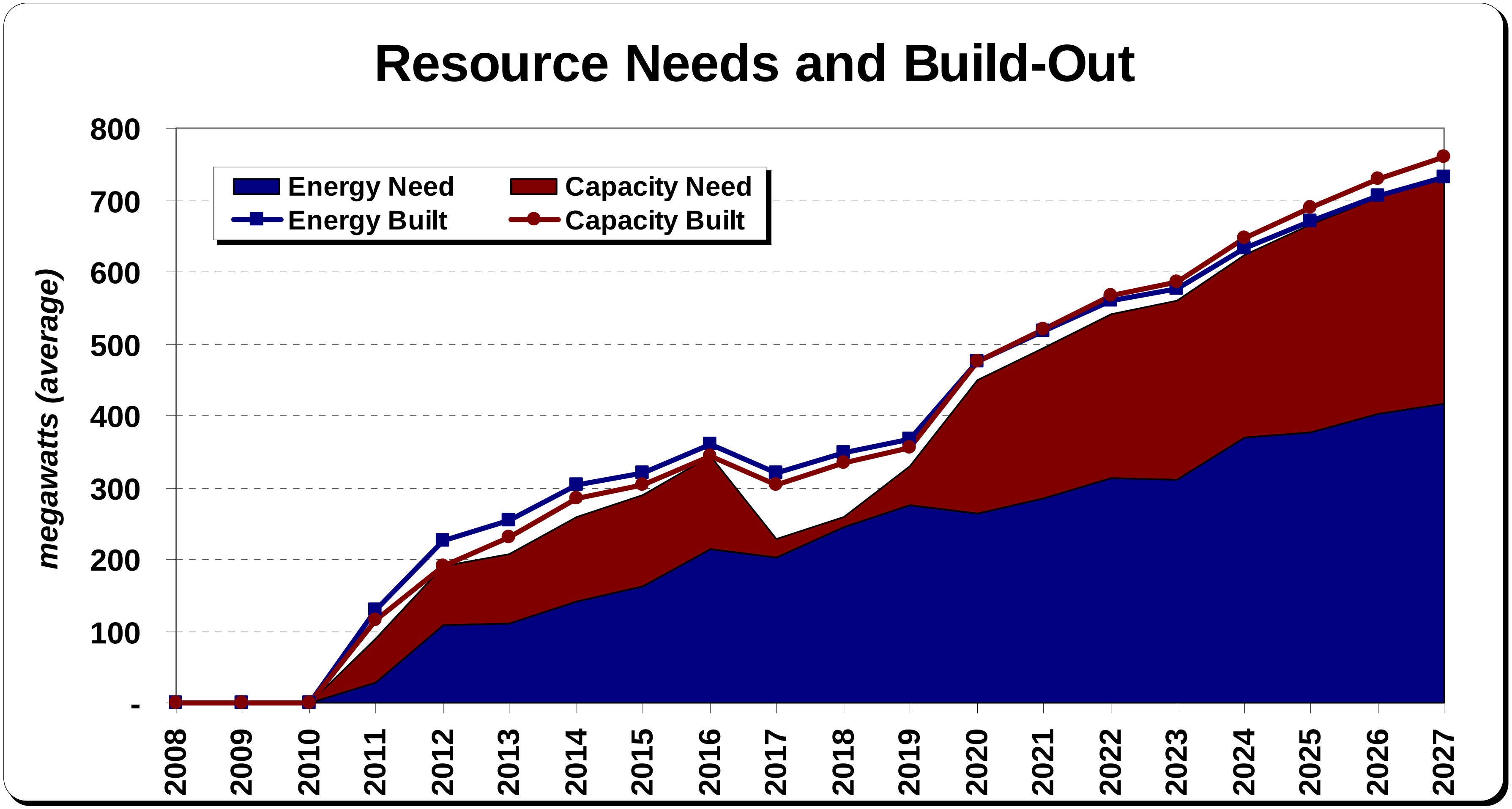
We answer to you.

Constraints

Resource
- Coal
  - Available after 2013
  - no NW pulverized
- Alberta Oil Sands
  - Available after 2013-no minimum constraint
- Wind
  - Columbia Basin: 200MW Tier 1, 100 MW Tier 2
  - Montana: No Constraints
  - Avista Service Territory Area: 200MW Tier 1, 200 MW Tier 2
  - 100MW limitation per year, 650 MW Total (including 100 MW RFP)
  - Capacity Contribution is 10%
- Other Renewables
  - Limited to 80MW first 10 Years and 160MW over 20-year horizon
- Nuclear available after 2025

Other Constraints
- Model builds to no more than 25 MW over capacity need
- Energy constraint is a minimum, therefore Avista will be energy long
- DSM will be updated for final study, uses 2005 IRP assumptions

We answer to you.



We answer to you.

DRAFT Resource Selection

- Avista is seeking guidance on the development of a 2007 Integrated Resource Plan (IRP) to forecast resource needs for the next twenty years.
- Resources shown on the following slides are a "DRAFT" set of resources that were found economic in the preliminary studies of the IRP to meet future load deficits, the final resource selection for the 2007 IRP will be available the summer of 2007.
- Avista is NOT actively pursuing any of the resources at this time, with exception of 100MW of wind identified in the 2005 IRP
- The final Preferred Resource Strategy may or may not include the resource on the following pages

Prior Preferred Resource Strategies (Energy)

Time Period	Resource Type	2007 "Draft" IRP	2005 IRP	2003 IRP
2007-2017	Coal	55	215	325
	Wind (nameplate)	300*	400	75
	Gas	110	0	200
	Other Renewables	73	57	0
	Conservation and Plant Upgrades	69	69	46
	Nuclear & Alberta Oil Sands	16	0	0
2007-2027	Coal	55	474	775
	Wind (nameplate)	300*	650	75
	Gas	110	0	200
	Other Renewables	145	137	0
	Conservation and Plant Upgrades	138	138	92
	Nuclear & Alberta Oil Sands	356	0	0

* Includes 100MW of RFP Wind

We answer to you.

Preliminary Avista Resource Selection (Nameplate MW)

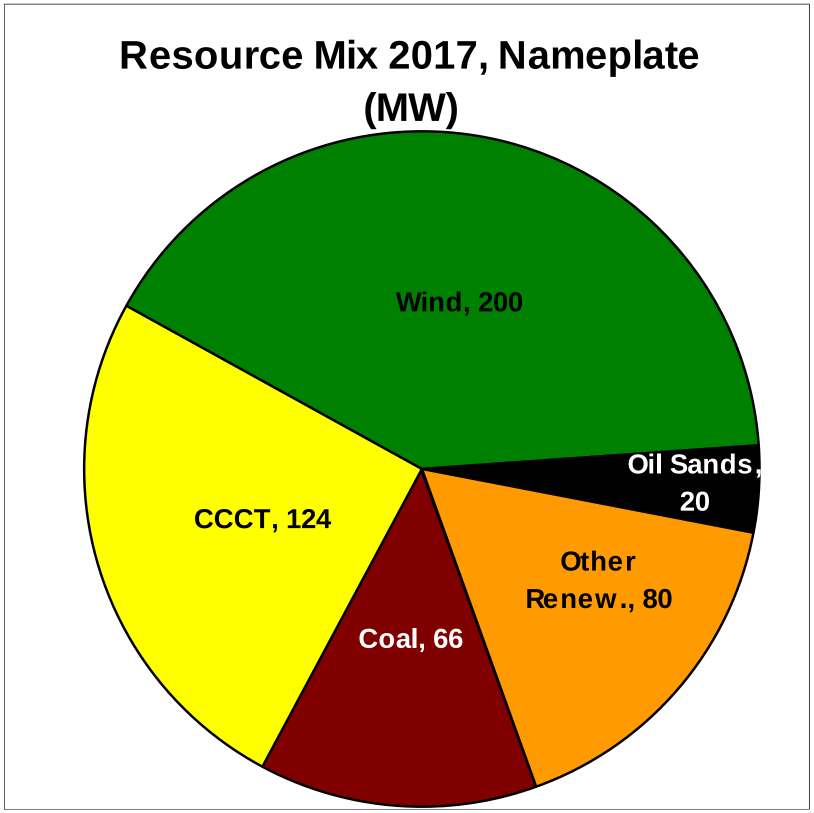
Year	Coal	CCCT	Wind	Oil Sands	Other Renewables	Nuclear
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0
2010	0	0	0	0	0	0
2011	0	57	100	0	50	0
2012	0	7	100	0	10	0
2013	66	16	0	0	10	0
2014	0	44	0	0	10	0
2015	0	0	0	20	0	0
2016	0	0	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	25	10	0
2019	0	0	0	13	10	0
2020	0	0	0	124	10	0
2021	0	0	0	40	10	0
2022	0	0	0	42	10	0
2023	0	0	0	10	10	0
2024	0	0	0	48	20	0
2025	0	0	0	0	0	43
2026	0	0	0	0	0	40
2027	0	0	0	0	0	31

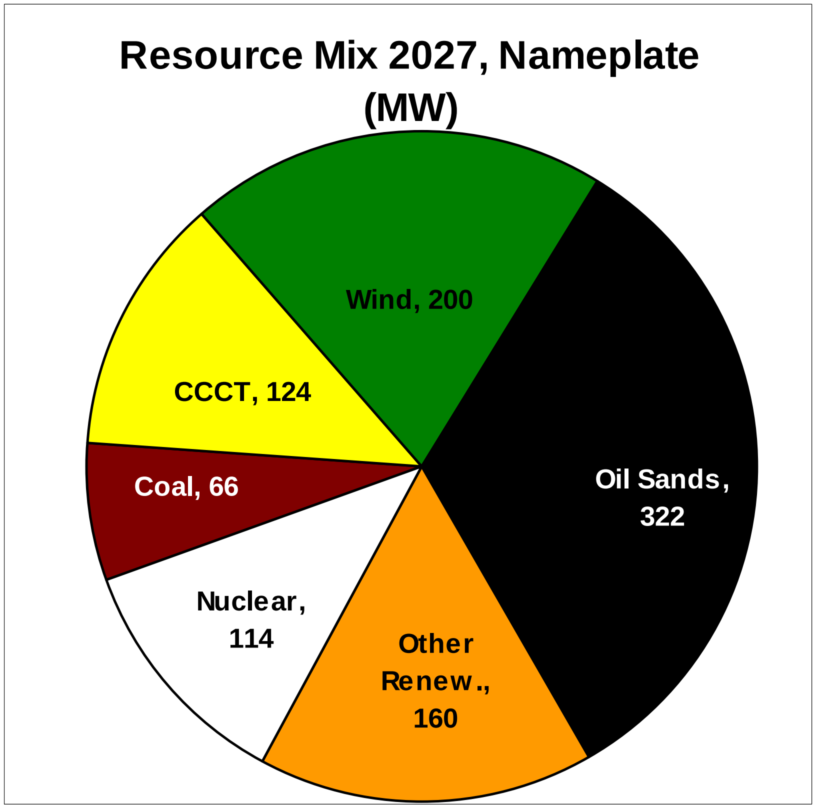
Base Case: PRS Model Details

Summary Stats for Scenario

Line	Values	100/0	90/10	75/25	50/50	25/75	10/90	0/100
1	NPV 17	1,563.8	1,576.2	1,576.7	1,765.7	1,920.7	1,920.7	2,015.9
2	NPV 27	3,509.4	3,552.8	3,639.1	3,844.5	4,246.2	4,246.2	4,463.6
3	Cost 2017	383.3	385.7	385.8	408.9	447.6	447.6	482.8
4	Cost 2027	803.5	810.1	820.0	771.4	800.9	800.9	831.1
5	St. Deviation 2017	72.1	62.9	62.9	53.1	47.6	47.6	47.2
6	St. Deviation 2027	151.7	126.7	92.3	78.2	62.9	62.9	62.7
7	Capital Cost 2017	311.8	388.6	388.6	1,091.2	1,587.4	1,587.4	1,838.4
8	Capital Cost 2027	284.8	842.2	1,869.4	1,821.4	2,451.0	2,451.0	2,461.5
9	Rate AARG 2017	5.0%	5.1%	5.1%	5.5%	6.2%	6.2%	6.7%
10	Rate AARG 2027	4.5%	4.5%	4.6%	4.3%	4.5%	4.5%	4.6%
11	Rate Max Year	9.9%	10.9%	9.7%	15.8%	18.0%	18.0%	18.0%
12	2017 95th% Diff	130.2	114.6	114.6	95.8	90.1	90.1	89.0
13	Coal Cap 17	0.0	0.0	0.0	64.5	133.3	133.3	133.3
14	CCCT Cap 17	0.0	254.7	254.7	121.7	43.8	43.8	43.8
15	CT Cap 17	254.7	0.0	0.0	0.0	0.0	0.0	0.0
16	Wind Cap 17	0.0	0.0	0.0	19.6	28.8	28.8	28.8
17	OtherRenew Cap 17	39.2	39.2	39.2	78.4	78.5	78.5	78.5
18	Other Cap 17	0.0	0.0	0.0	18.1	18.1	18.1	18.1
19	Coal Cap 27	0.0	0.0	0.0	64.5	133.3	133.3	133.3
20	CCCT Cap 27	0.0	254.7	254.7	121.7	43.8	43.8	43.8
21	CT Cap 27	695.5	290.0	0.0	0.0	0.0	0.0	0.0
22	Wind Cap 27	0.0	0.0	0.0	19.6	52.8	52.8	52.8
23	OtherRenew Cap 27	39.2	78.5	117.7	156.9	157.0	157.0	157.0
24	Other Cap 27	0.0	111.6	387.3	396.9	372.9	372.9	372.9

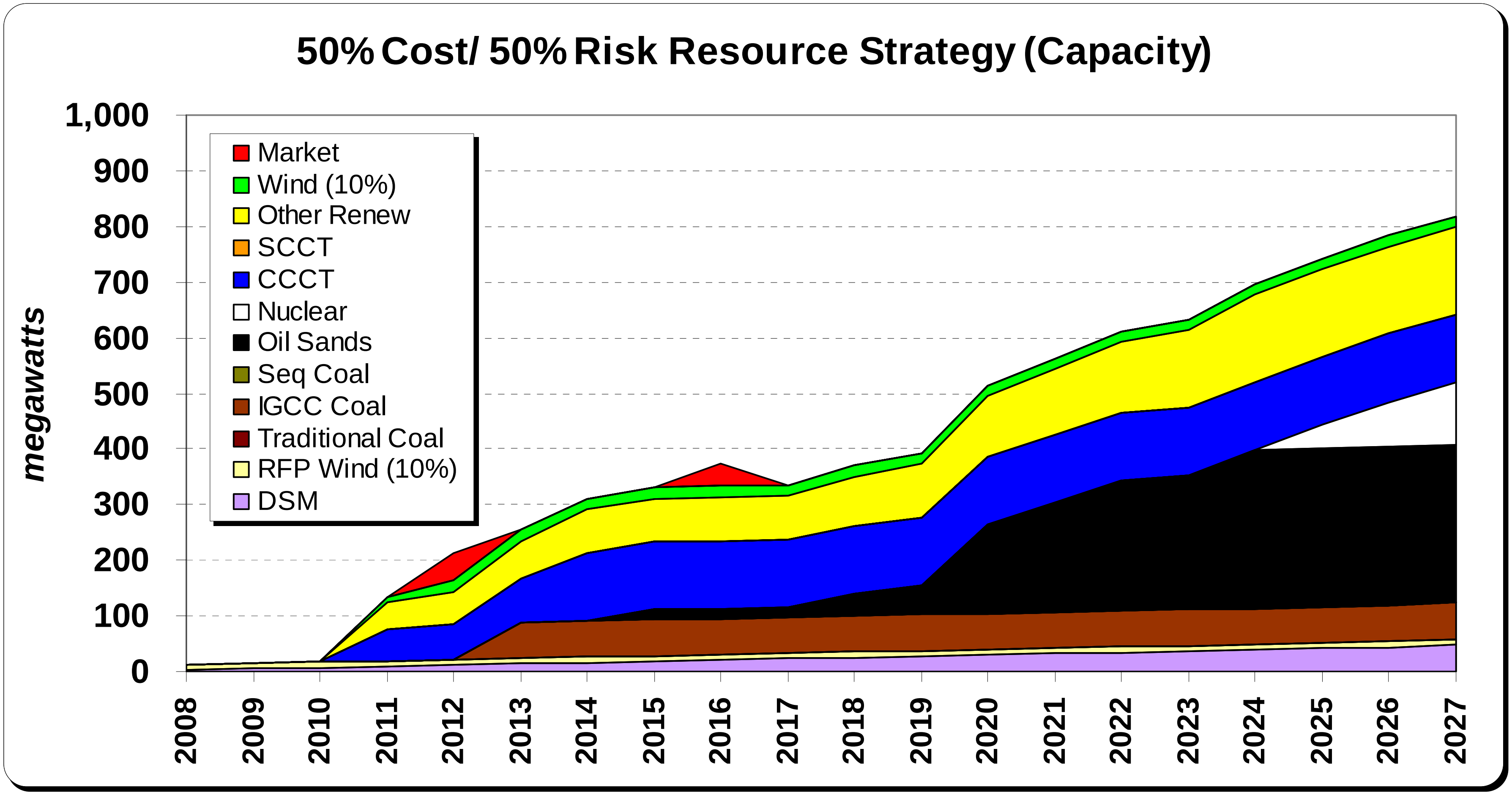
New Resource Mix (2017 & 2027)





We answer to you.

AVISTA



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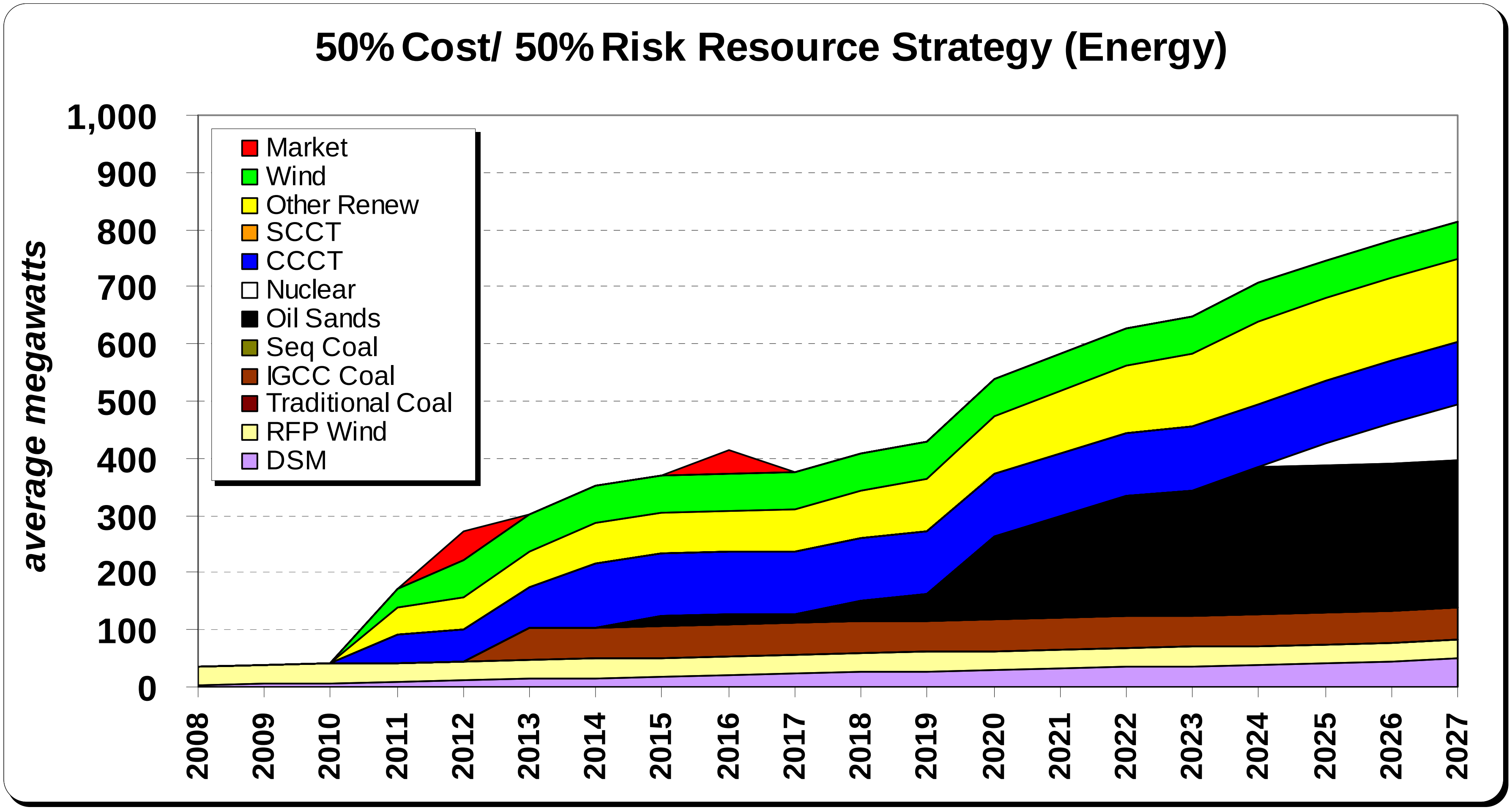
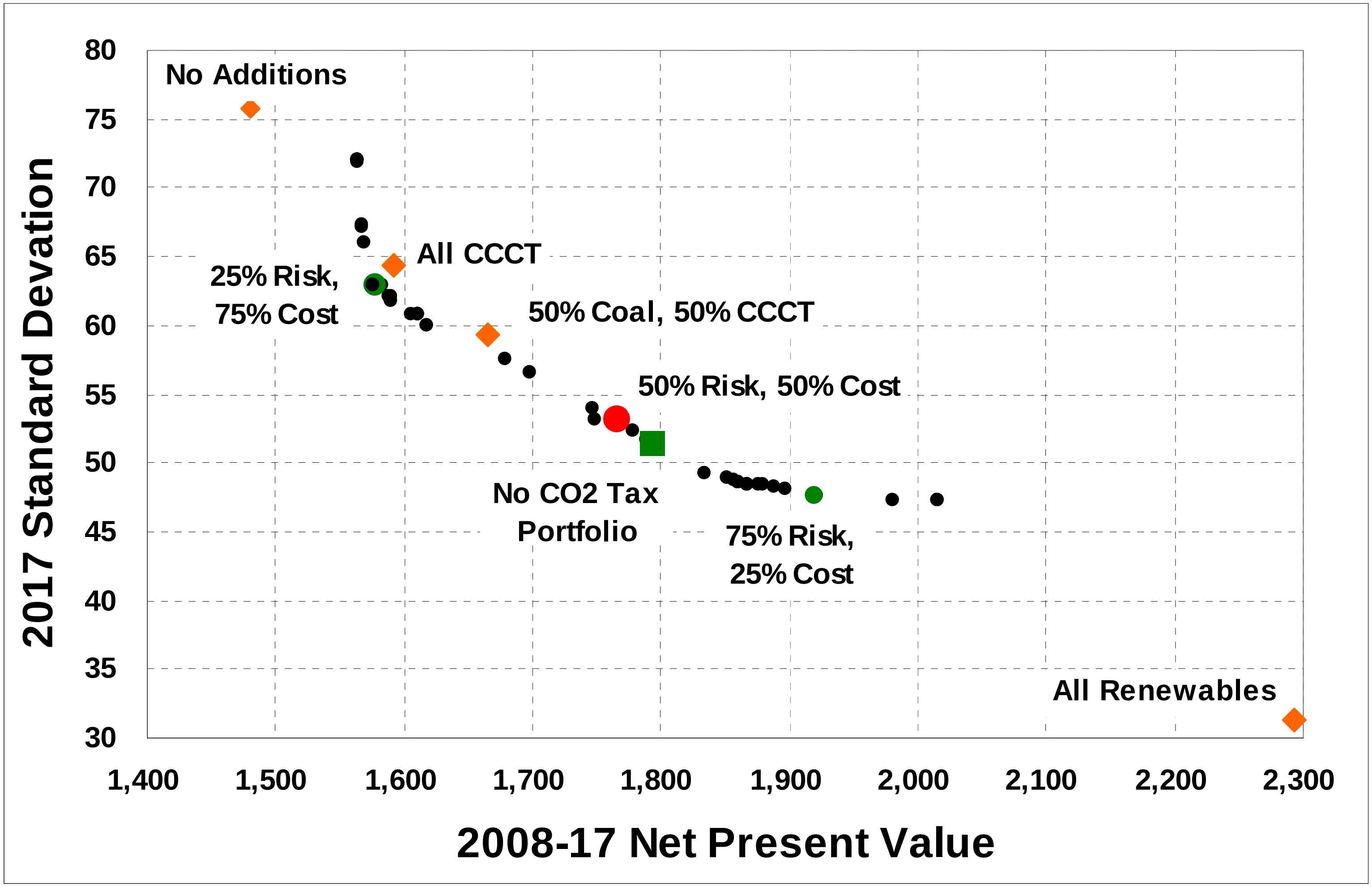
AVISTA



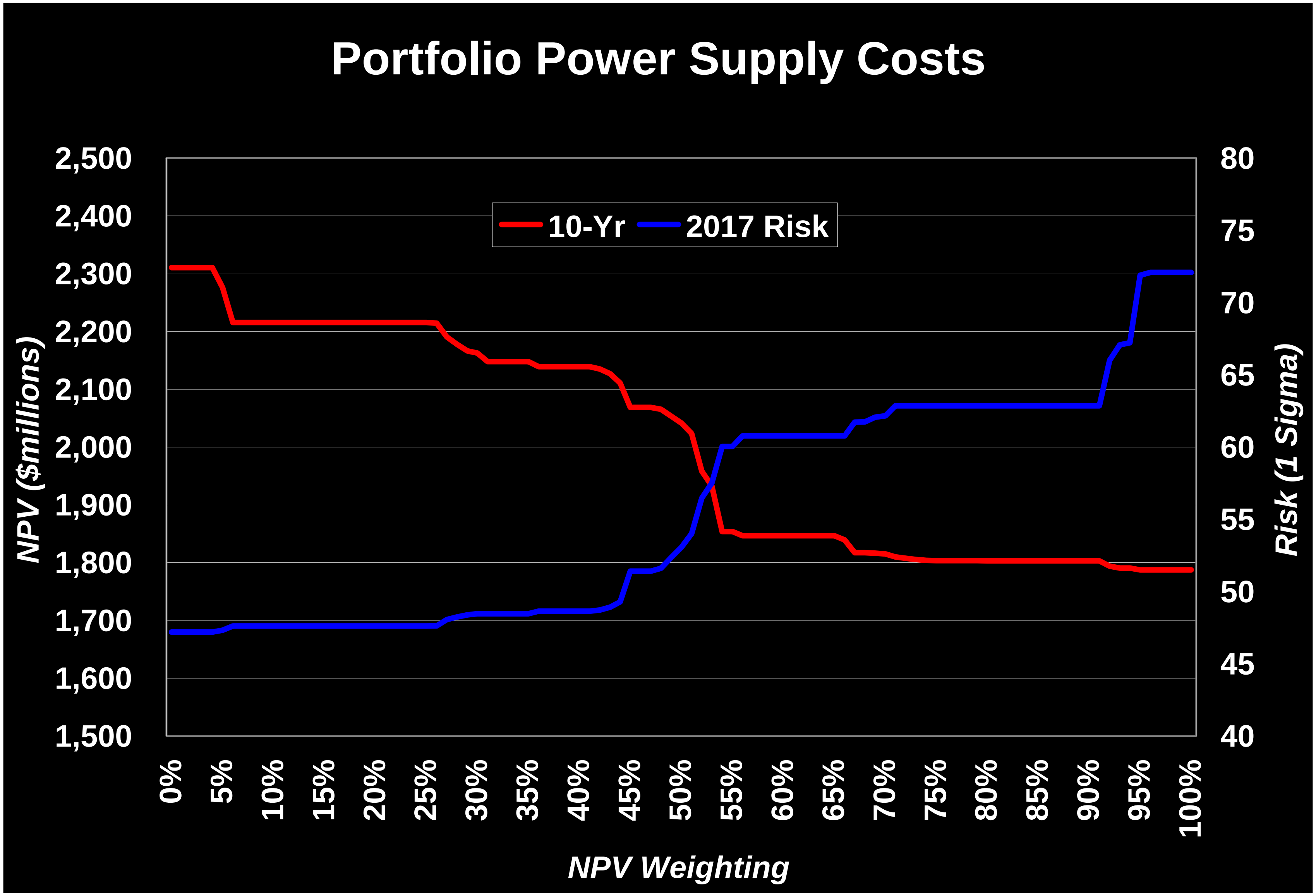
We answer to you.

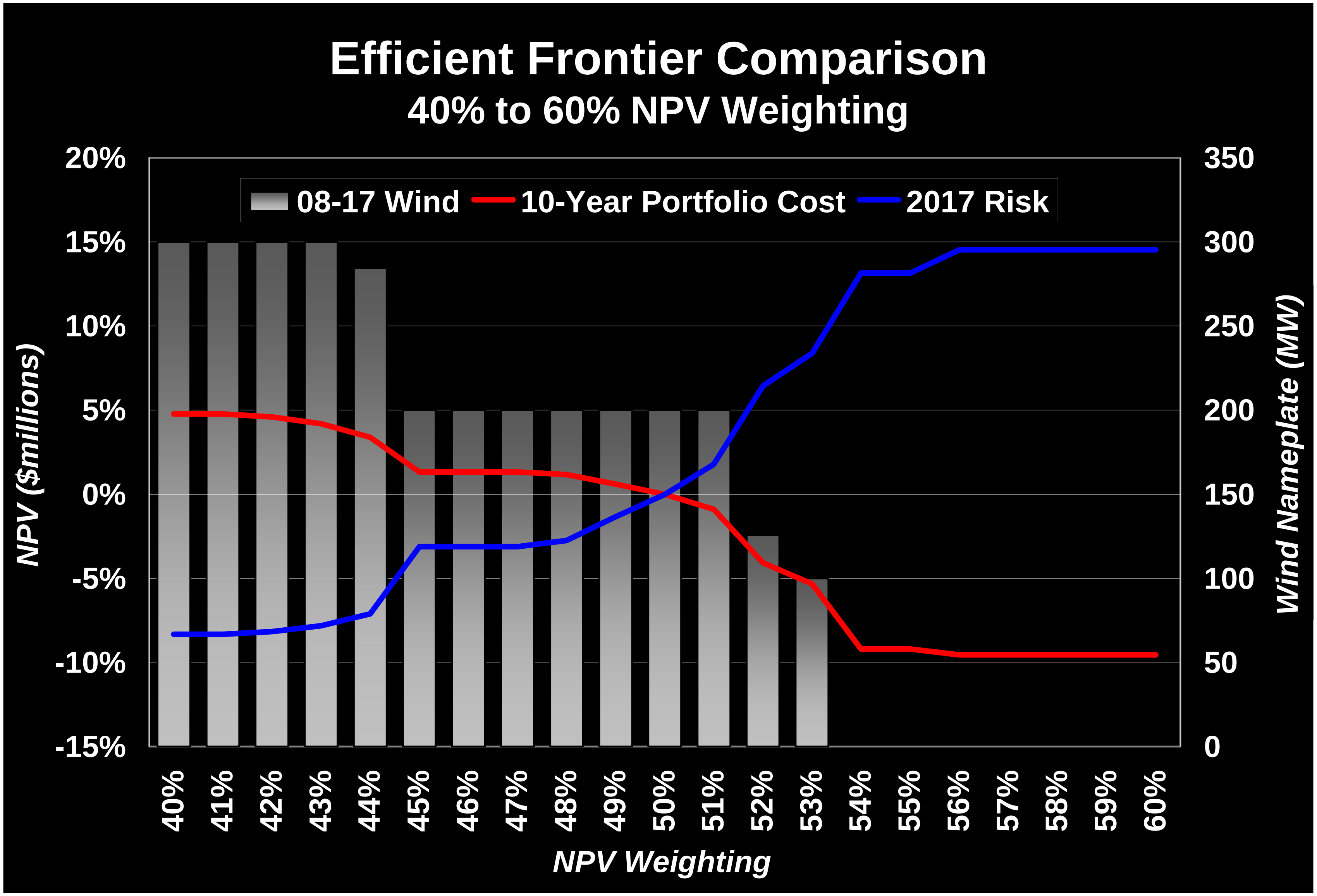
Efficient Frontier



We answer to you.

AVISTA




Efficient Frontier Comparison
40% to 60% NPV Weighting
08-17 Wind
10-Year Portfolio Cost
2017 Risk
NPV ($millions)
20%
15%
10%
5%
0%
-5%
-10%
-15%
Wind Nameplate (MW)
350
300
250
200
150
100
50
0
40%
41%
42%
43%
44%
45%
46%
47%
48%
49%
50%
51%
52%
53%
54%
55%
56%
57%
58%
59%
60%
NPV Weighting

We answer to you.

No CO2 Taxation: PRS Model Details

Summary Stats for Scenario

Line	Values	100/0	90/10	75/25	50/50	25/75	10/90	0/100
1	NPV 17	1,507.3	1,523.1	1,528.6	1,736.8	1,868.6	1,868.6	1,961.1
2	NPV 27	3,305.1	3,335.9	3,413.2	3,665.7	4,054.7	4,054.7	4,239.8
3	Cost 2017	348.0	350.1	349.6	382.1	414.0	414.0	447.5
4	Cost 2027	738.4	746.0	749.9	713.8	757.6	757.6	778.0
5	St. Deviation 2017	70.3	58.9	58.9	46.9	42.9	42.9	42.3
6	St. Deviation 2027	155.6	136.9	94.3	70.2	56.6	56.6	56.2
7	Capital Cost 2017	208.0	388.6	387.2	1,208.7	1,587.4	1,587.4	1,838.4
8	Capital Cost 2027	284.8	355.0	1,583.8	1,773.8	2,423.8	2,423.8	2,423.8
9	Rate AARG 2017	4.4%	4.4%	4.4%	5.0%	5.6%	5.6%	6.2%
10	Rate AARG 2027	4.1%	4.2%	4.2%	4.0%	4.2%	4.2%	4.4%
11	Rate Max Year	6.5%	6.6%	8.8%	15.8%	18.0%	18.0%	18.0%
12	2017 95th% Diff	115.7	100.0	100.0	81.3	73.6	73.6	72.8
13	Coal Cap 17	0.0	0.0	0.0	141.3	133.3	133.3	133.3
14	CCCT Cap 17	0.0	254.7	254.7	63.0	43.8	43.8	43.8
15	CT Cap 17	284.1	0.0	0.0	0.0	0.0	0.0	0.0
16	Wind Cap 17	0.0	0.0	0.0	19.6	28.8	28.8	28.8
17	OtherRenew Cap 17	9.8	39.2	39.2	78.4	78.5	78.5	78.5
18	Other Cap 17	0.0	0.0	0.0	0.0	18.1	18.1	18.1
19	Coal Cap 27	0.0	0.0	406.9	184.0	133.3	133.3	133.3
20	CCCT Cap 27	0.0	455.8	254.7	63.0	43.8	43.8	43.8
21	CT Cap 27	724.9	239.7	0.0	0.0	0.0	0.0	0.0
22	Wind Cap 27	0.0	0.0	0.0	19.6	52.8	52.8	52.8
23	OtherRenew Cap 27	9.8	39.2	98.1	156.9	157.0	157.0	157.0
24	Other Cap 27	0.0	0.0	0.0	336.1	372.9	372.9	372.9

We answer to you.

AVISTA

Wind Capital Cost Sensitivities

Wind Capital Costs ($ per KW)	**Nameplate: 2008-17** (limit 200MW & PTC)	**Nameplate: 2018-27** (limit 250MW & No PTC)
$2,000	0	0
$1,800	0	0
$1,700	100 MW	0
$1,600	200 MW	0
$1,500	200 MW	100 MW
$1,200	200 MW	250 MW

Avista Utilities 2007 Integrated Resource Plan

Technical Advisory Committee Meeting No. 3 Agenda

Wednesday January 10, 2007

	Topic	Time	Staff
1.	Introductions	9:00	Barcus
2.	Review & Feedback of 2nd TAC	9:15	Lyons
3.	Draft PRS Review	9:30	Gall/Lyons
4.	Fuel Price Forecast	11:30	Christie/Gall
5.	Lunch – Clean Coal Presentation	12:00	Lafferty
6.	Emissions Update	12:45	Lyons
7.	Load Forecast	1:30	Barcus
8.	Conservation	2:30	Folsom & Powell
9.	Adjourn	4:30	

We answer to you.

AVISTA

2007 Electric Integrated Resource Plan Third Technical Advisory Committee Meeting

January 10, 2007

Topic	Presenter
Review & Feedback of 2nd TAC	Lyons
Draft PRS Review	Gall/Lyons
Fuel Price Forecast	Christie/Gall
Clean Coal Technologies	Lyons
Emissions Update	Lyons
Load Forecast	Barcus
Conservation	Folsom & Powell

We answer to you.

Review & Feedback: Second TAC Meeting

2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 10, 2007

John Lyons

We answer to you.

TAC Meeting #2 – August 31, 2006 & September 1, 2006

- All of the past TAC meeting notes are available on the Avista web site
- Reviewed 2005 Action Plan
- IRP Modeling Overview
- Lunch presentations on the 2006 Renewables RFP and Alternative Energy Future
- Future resource requirements
- Review of preliminary futures and scenarios market results
- Review of the preliminary Preferred Resource Strategy

We answer to you.

Questions from TAC Meeting #2

- Editorial updates to several slides for clarification – done on web site
- Gas basin differentials – covered in the Fuel Price Forecast later today
- Continue to work on increasing attendance – additional phone calls and emails

The following will be included in the final 2007 IRP:

- Highlight the efficient frontier model in the 2007 IRP
- Determine the amount of conservation needed to defer new coal or a CT
- Verify that Northwest utilities are not going after the same wind supply curve
- Determine how much of a resource cushion is needed or is acceptable
- Regional wind resource adequacy
- Address the free rider problem associated with not adding resources
- Include a thorough discussion of our definition of risk
- Utilizing a probability distribution for CO_2 in the Base Case

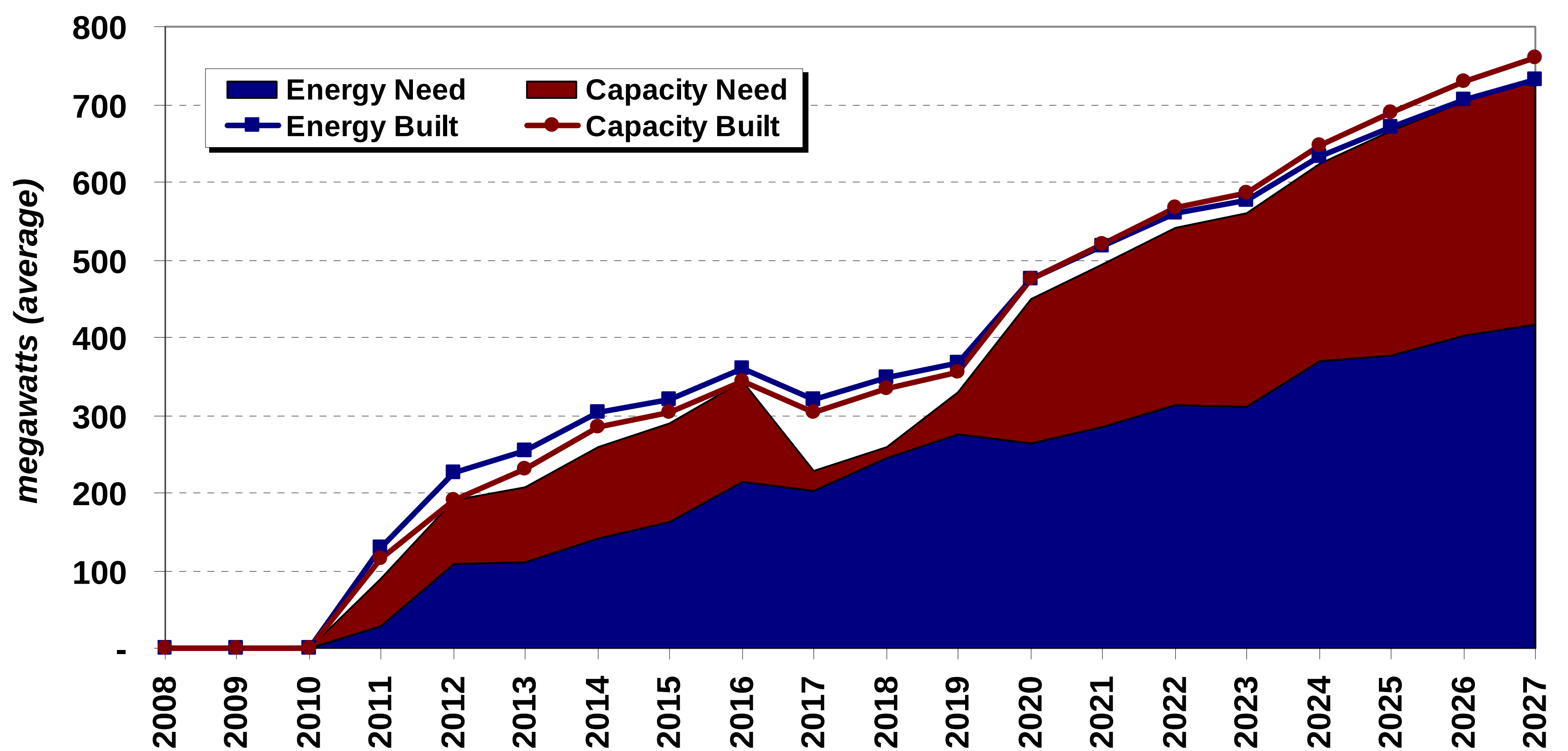
Draft Preferred Resource Strategy Review

2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 10, 2007

James Gall & John Lyons

We answer to you.

Resource Needs and Build-Out



We answer to you.

AVISTA

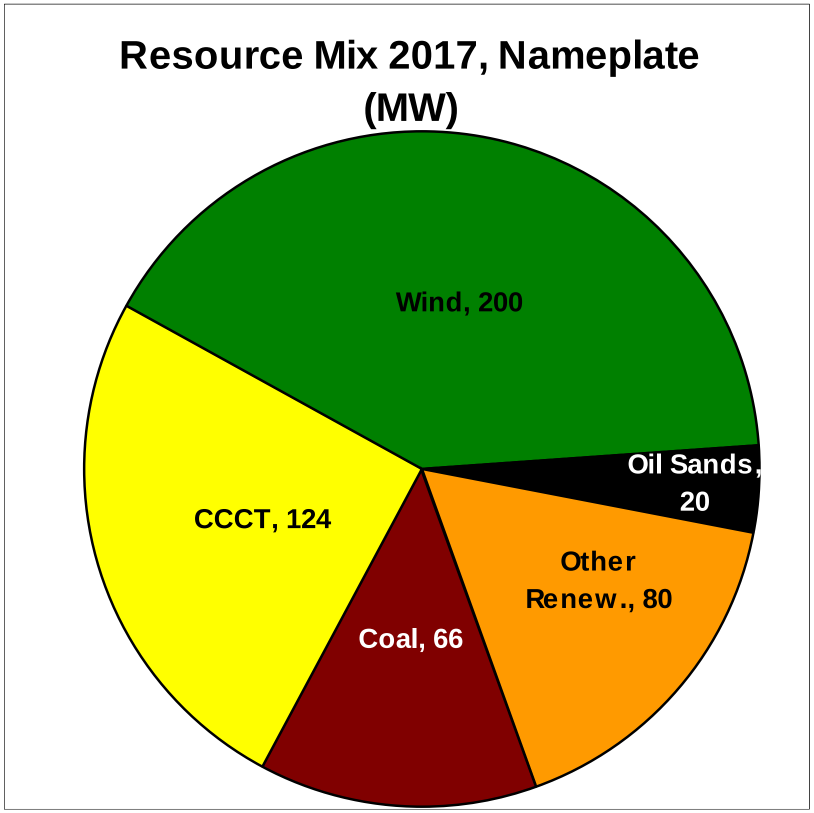
DRAFT Preferred Resource Strategies (Energy)

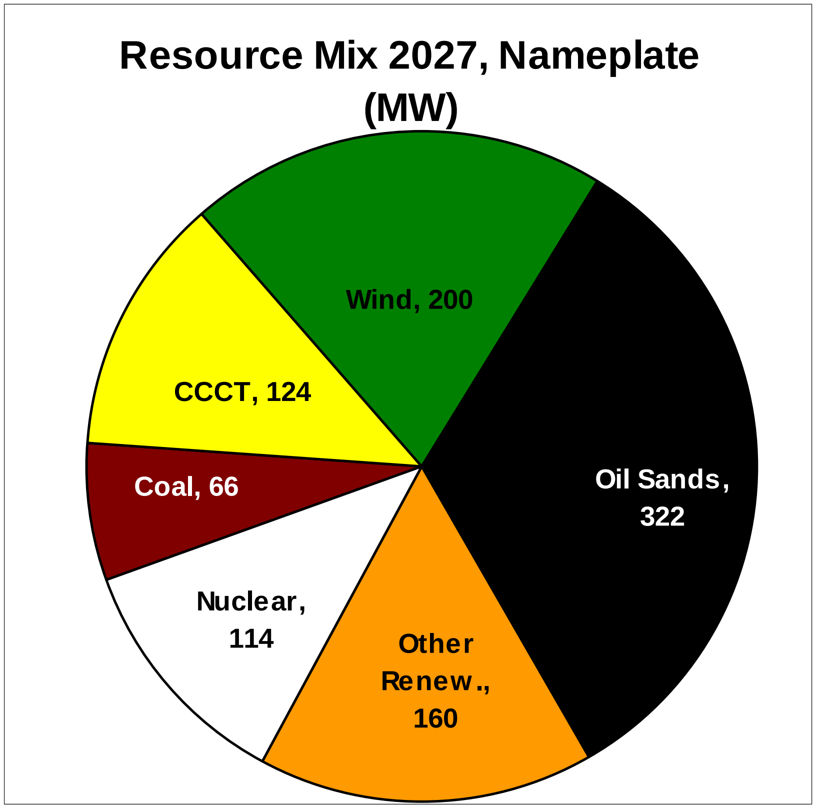
Time Period	Resource Type	2007 "Draft" IRP	2005 IRP	2003 IRP
2007-2017	Coal	55	215	325
	Wind (nameplate)	300*	400	75
	Gas	110	0	200
	Other Renewables	73	57	0
	Conservation and Plant Upgrades	69	69	46
	Nuclear & Alberta Oil Sands	16	0	0
2007-2027	Coal	55	474	775
	Wind (nameplate)	300*	650	75
	Gas	110	0	200
	Other Renewables	145	137	0
	Conservation and Plant Upgrades	138	138	92
	Nuclear & Alberta Oil Sands	356	0	0

* Includes 100 MW of RFP Wind

We answer to you.

DRAFT New Resource Mix (2017 & 2027)

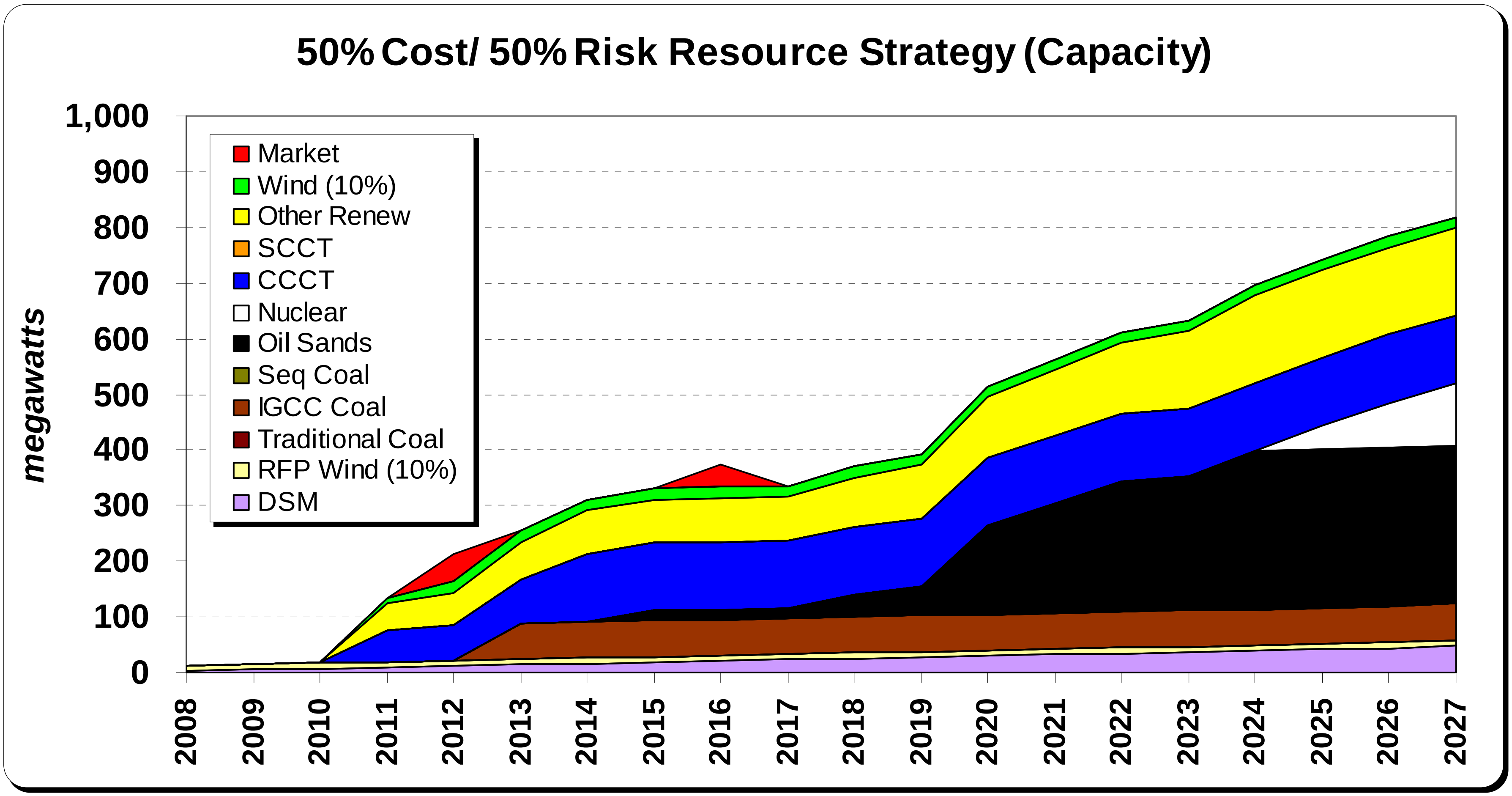




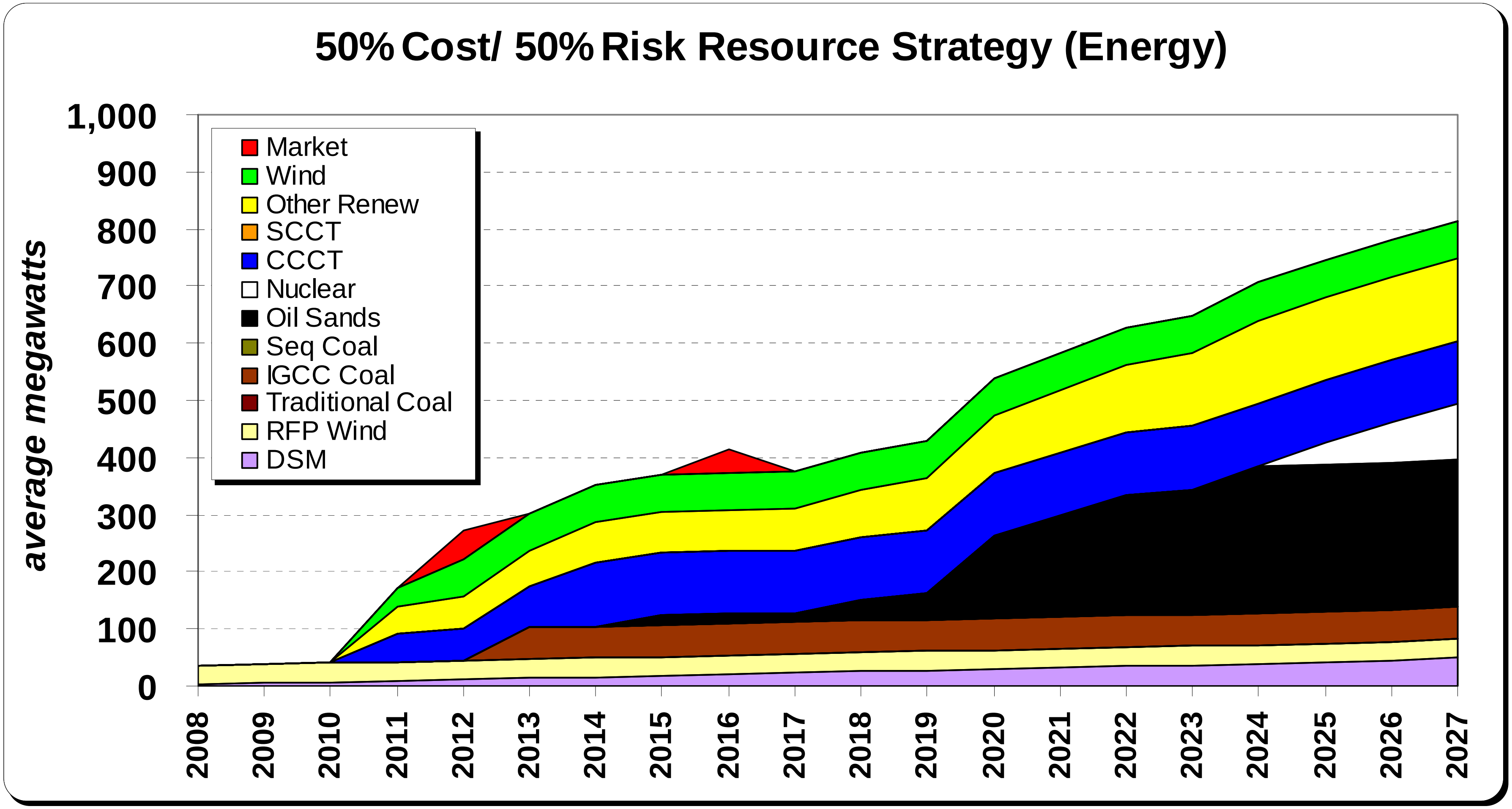
* Does not include the 100 MW of RFP wind

We answer to you.

AVISTA



We answer to you.



We answer to you.

Base Case: DRAFT PRS Model Details

Summary Stats for Scenario

Line	Values	100/0	90/10	75/25	50/50	25/75	10/90	0/100
1	NPV 17	1,563.8	1,576.2	1,576.7	1,765.7	1,920.7	1,920.7	2,015.9
2	NPV 27	3,509.4	3,552.8	3,639.1	3,844.5	4,246.2	4,246.2	4,463.6
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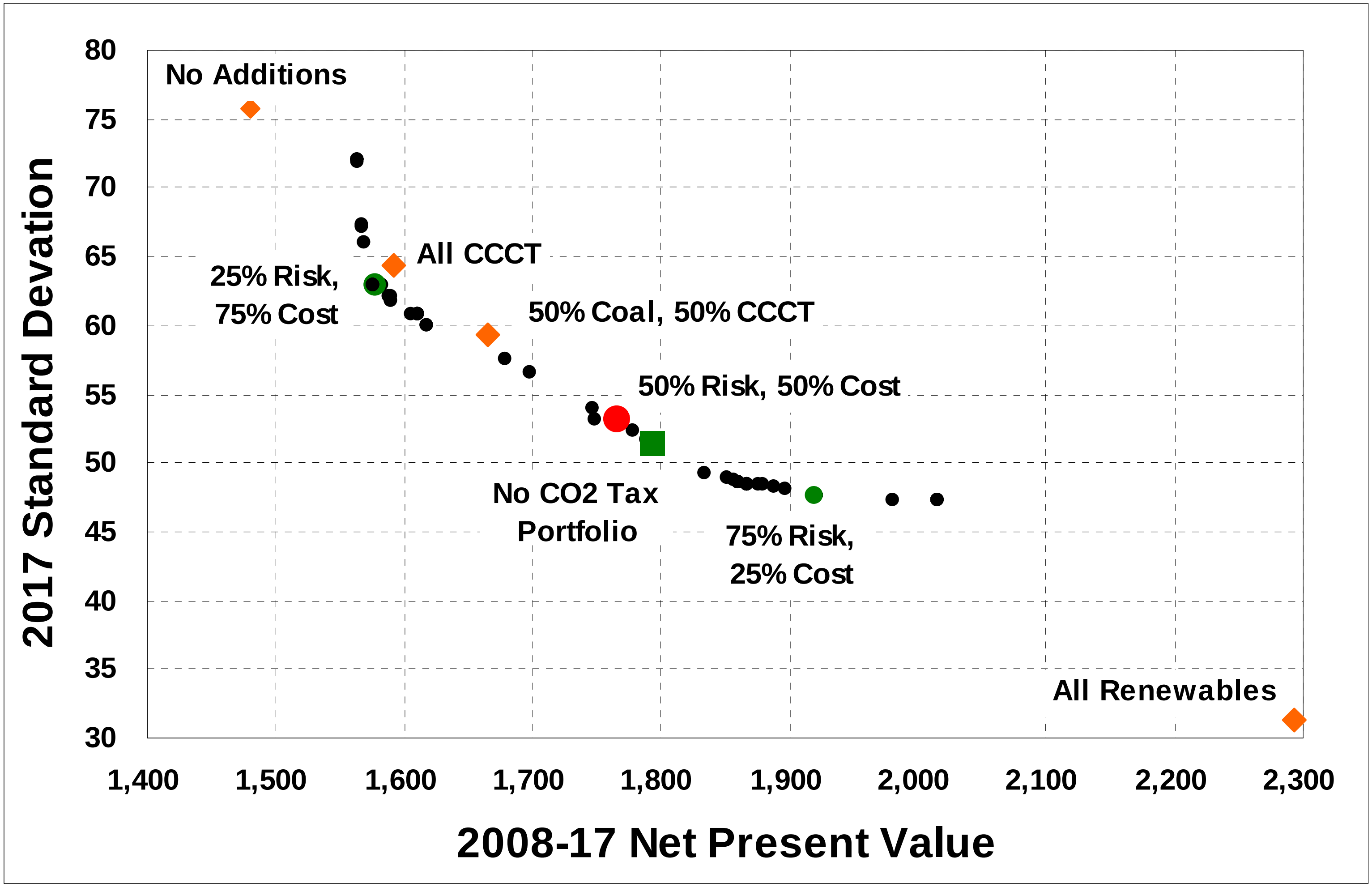
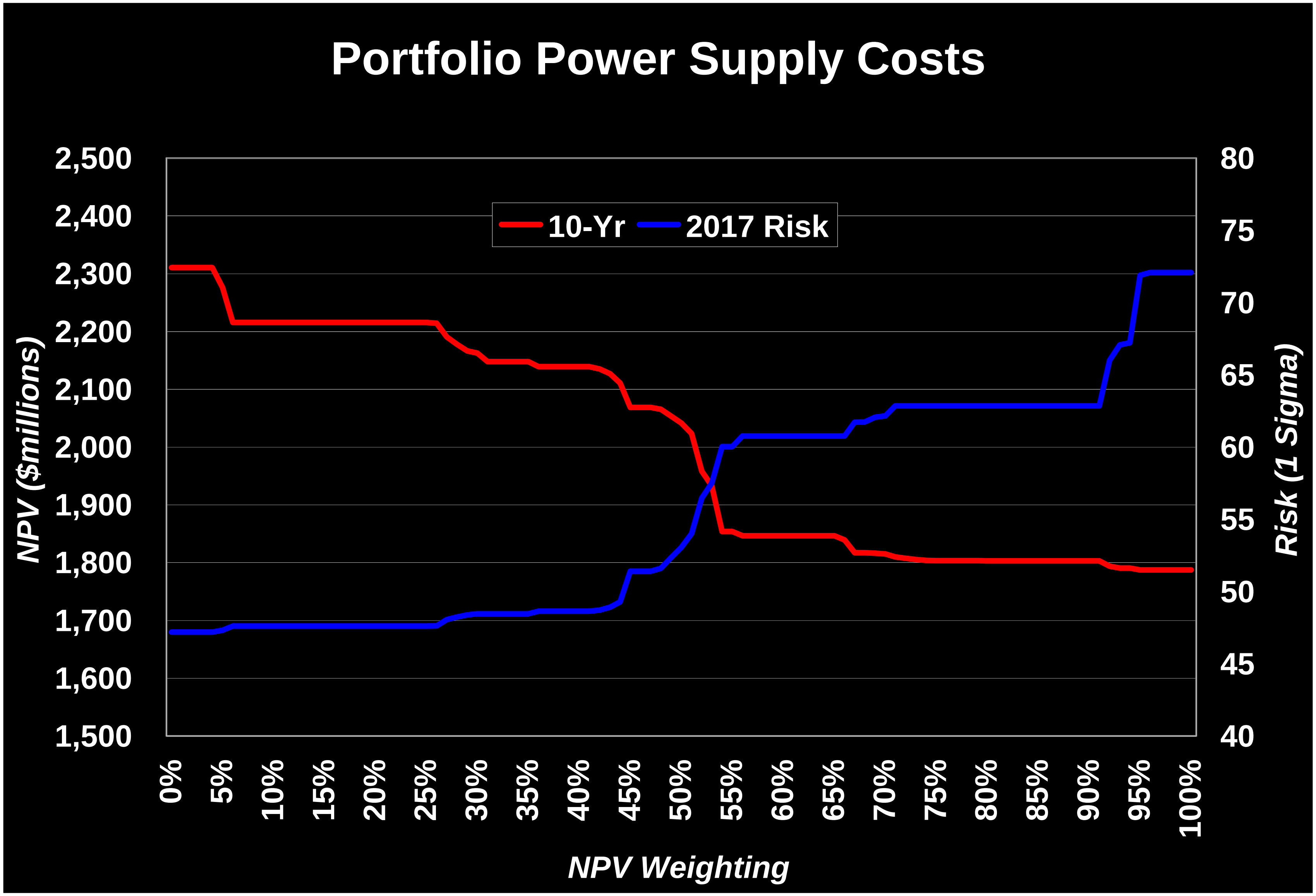
8	Capital Cost 2027	284.8	842.2	1,869.4	1,821.4	2,451.0	2,451.0	2,461.5
9	Rate AARG 2017	5.0%	5.1%	5.1%	5.5%	6.2%	6.2%	6.7%
10	Rate AARG 2027	4.5%	4.5%	4.6%	4.3%	4.5%	4.5%	4.6%
11	Rate Max Year	9.9%	10.9%	9.7%	15.8%	18.0%	18.0%	18.0%
12	2017 95th% Diff	130.2	114.6	114.6	95.8	90.1	90.1	89.0
13	Coal Cap 17	0.0	0.0	0.0	64.5	133.3	133.3	133.3
14	CCCT Cap 17	0.0	254.7	254.7	121.7	43.8	43.8	43.8
15	CT Cap 17	254.7	0.0	0.0	0.0	0.0	0.0	0.0
16	Wind Cap 17	0.0	0.0	0.0	19.6	28.8	28.8	28.8
17	OtherRenew Cap 17	39.2	39.2	39.2	78.4	78.5	78.5	78.5
18	Other Cap 17	0.0	0.0	0.0	18.1	18.1	18.1	18.1
19	Coal Cap 27	0.0	0.0	0.0	64.5	133.3	133.3	133.3
20	CCCT Cap 27	0.0	254.7	254.7	121.7	43.8	43.8	43.8
21	CT Cap 27	695.5	290.0	0.0	0.0	0.0	0.0	0.0
22	Wind Cap 27	0.0	0.0	0.0	19.6	52.8	52.8	52.8
23	OtherRenew Cap 27	39.2	78.5	117.7	156.9	157.0	157.0	157.0
24	Other Cap 27	0.0	111.6	387.3	396.9	372.9	372.9	372.9

We answer to you.

Efficient Frontier



We answer to you.



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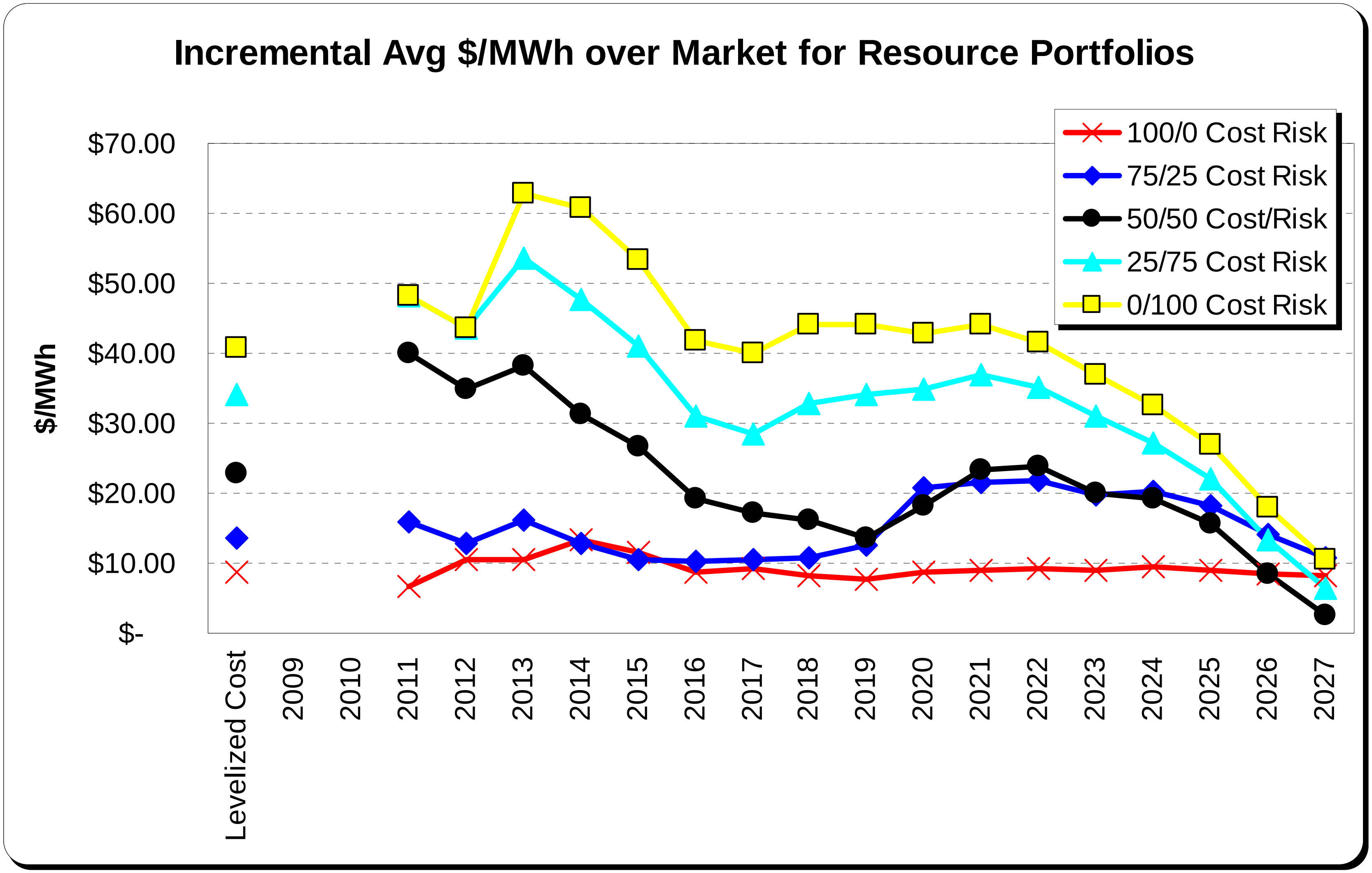


We answer to you.

Fuel Price Forecast

2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 10, 2007

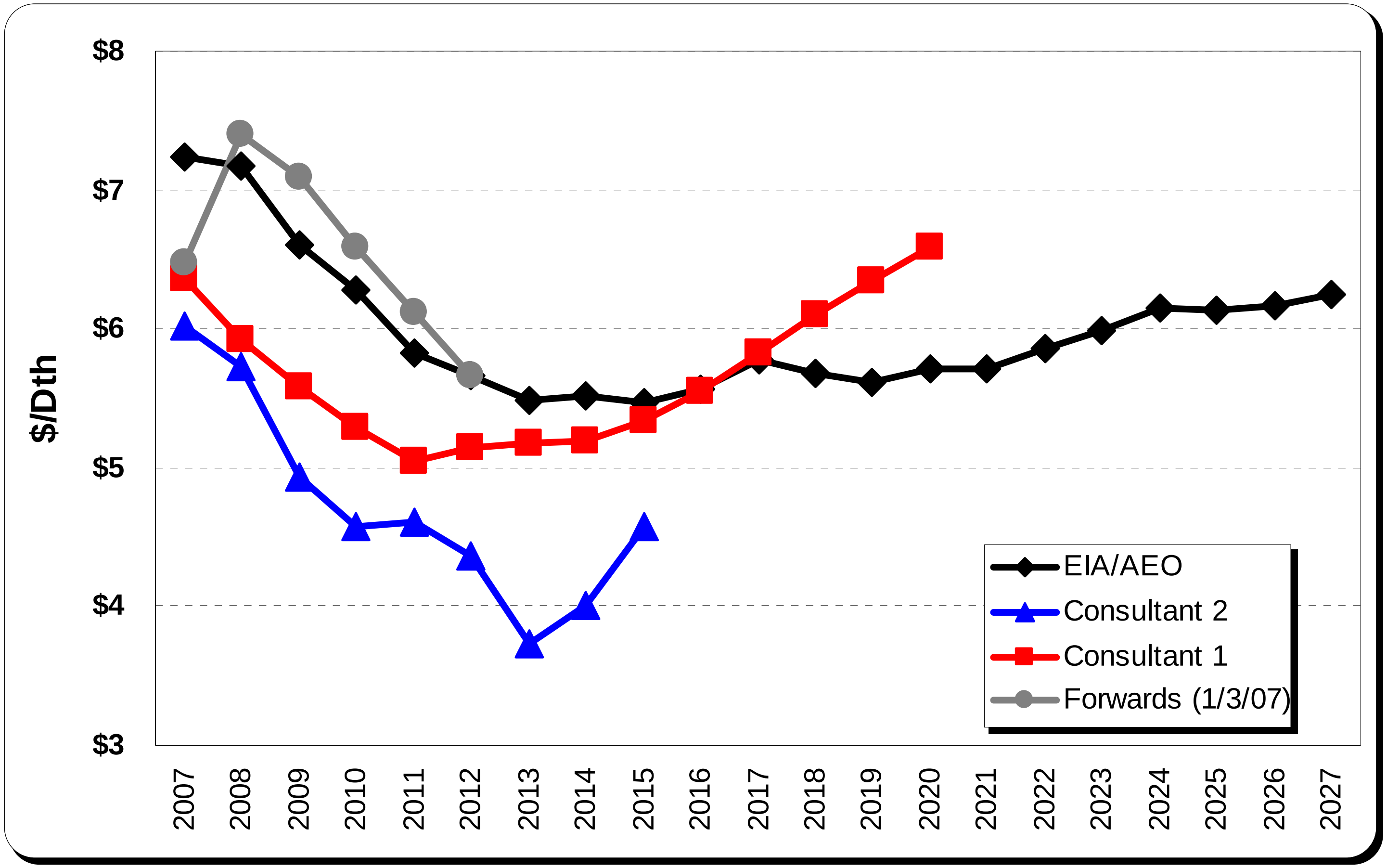
Kevin Christie & James Gall

Levelized Natural Gas and Coal Costs

20-Year Levelized (2008 to 2027) shown in 2007 dollars	Nominal Price per Dth	Real Price per Dth
Henry Hub NG	$7.83	$6.59
AECO NG	$6.67	$5.61
Sumas NG	$6.74	$5.67
Mine Mouth PRB Coal	$0.61	$0.52
Short Haul PRB Coal	$1.19	$1.00
Long Haul PRB Coal	$2.90	$2.44

We answer to you.

Henry Hub Price Forecasts (2005$)



We answer to you.

Forecast Assumptions

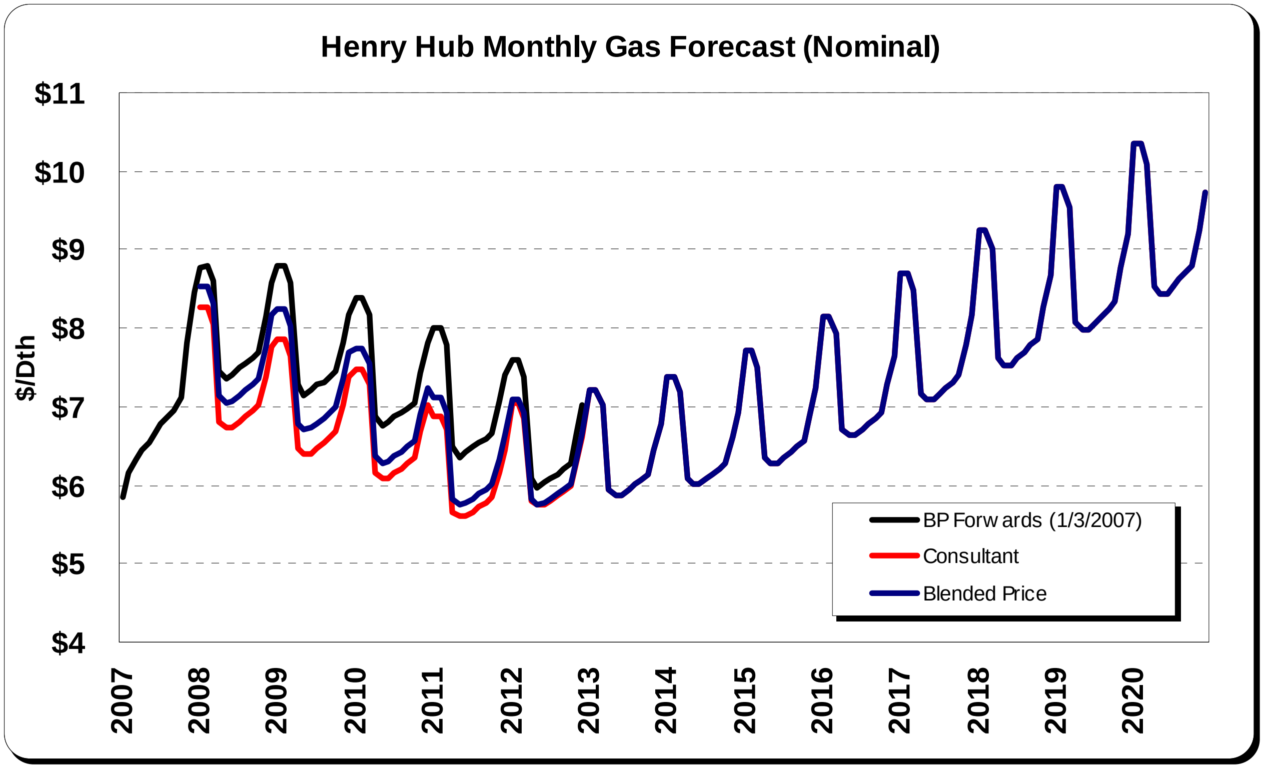
	Consultant 1			Consultant 2			AEO 2007		
	2006	2010	2015	2006	2010	2015	2006	2010	2015
Forecasted HH Price (2005$)	$ 6.39	$ 5.29	$ 5.33	$ 6.46	$ 4.57	$ 4.57	$ 7.07	$ 6.28	$ 5.46
US Economic Growth (% GDP)	3.50%	3.20%	3.20%	3.00%	3.00%	3.00%	2.90%	2.90%	2.90%
US Gas Demand (bcf/d)	60.52	65.86	68.27	58.40	64.40	67.80	59.50	65.80	69.38
EG Demand (bcf\d)	17.89	19.81	21.54	16.60	22.10	25.40	16.11	17.48	19.48
WTI Oil Price (2005$)	$ 65.00	$ 53.54	$ 50.52	$ 55.15	$ 49.90	$ 44.45	$ 61.75	$ 57.47	$ 49.87
US Gas Prod. (bcf\d)	51.53	52.45	49.77	49.40	48.00	46.50	51.07	53.21	53.89
LNG Imports (bcf\d)	1.61	5.82	10.28	1.60	8.10	11.80	1.51	4.96	8.19
Net Imports (bcf\d)	8.25	7.60	8.22	8.30	8.30	9.00	7.50	7.50	7.20
Mackenzie Delta Pipeline		In service 2014			In service 2012				
Alaska Pipeline			In service 2020			In service 2017			In service 2018

We answer to you.

AVISTA

Methodology

- NYMEX forwards (1/03/2007)
- Long-term fundamentals based forecast (consultant)
- Prices after 2020 grow at the last 5 years average growth rate

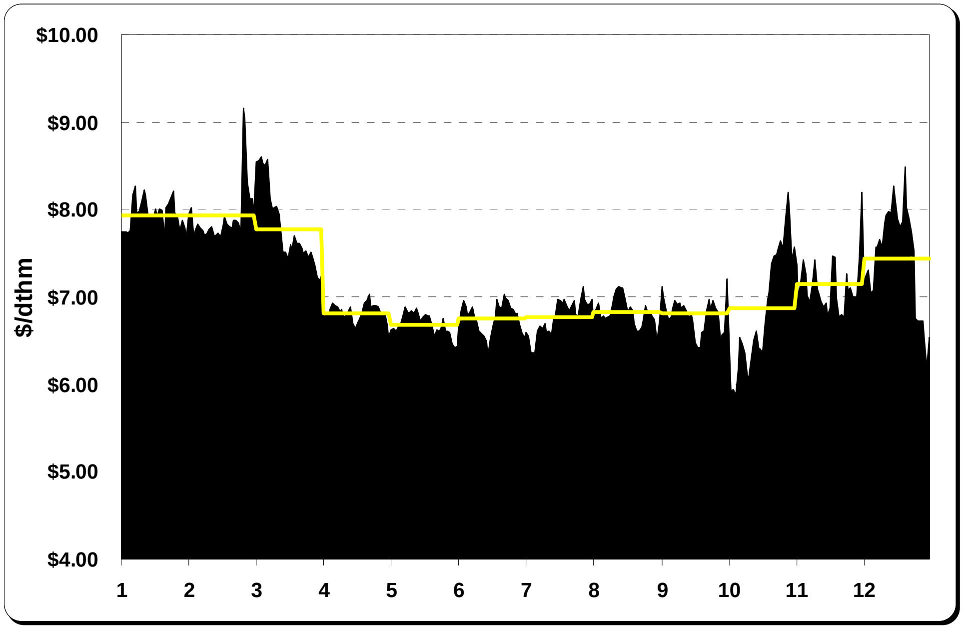


Intra Year Gas Prices

Month	Percent of Annual	Month	Percent of Annual
Jan	113%	Jul	93%
Feb	113%	Aug	94%
Mar	110%	Sep	95%
Apr	93%	Oct	96%
May	92%	Nov	101%
Jun	92%	Dec	106%

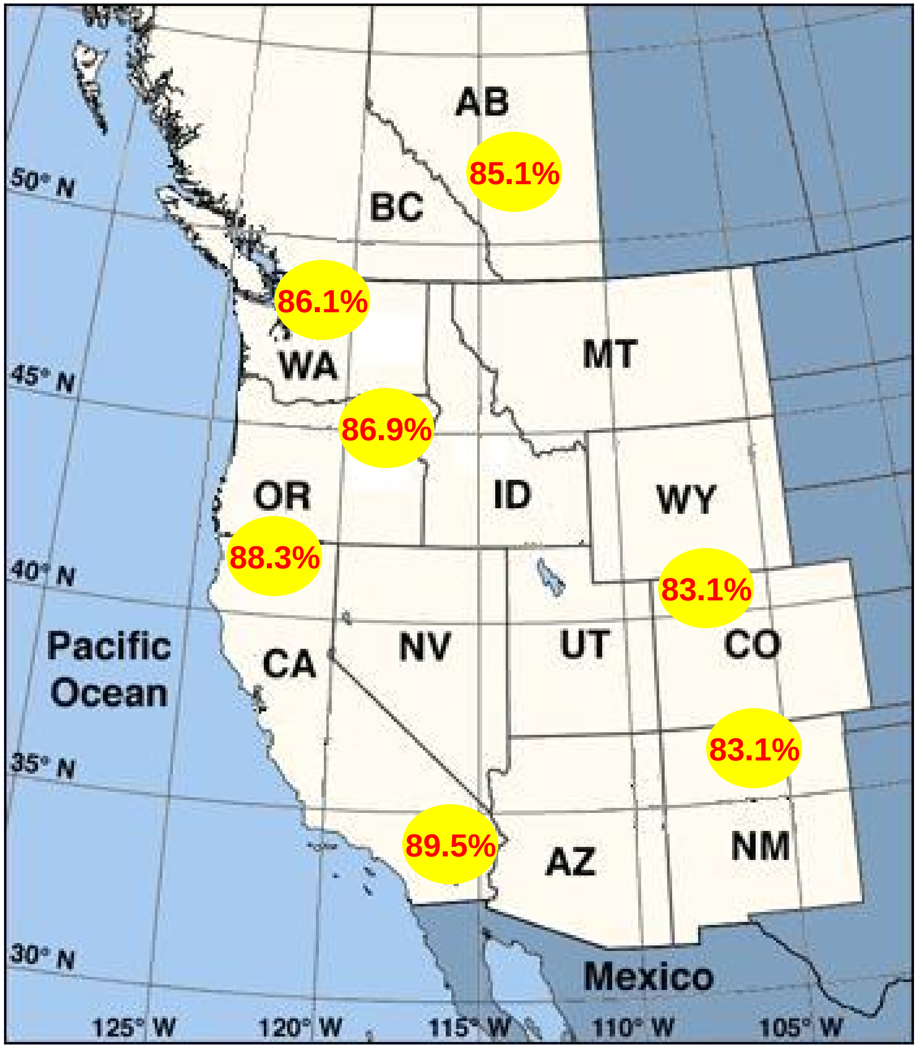
Monthly Gas Shape: Consistent with 2006 Gas IRP methodology where the monthly shape is calculated by the average of monthly forward prices available on January 3, 2007. All gas prices use this monthly shape.

Daily Gas Shape: Average daily percent change from the monthly average price from 2003 to 2006 at AECO



We answer to you.

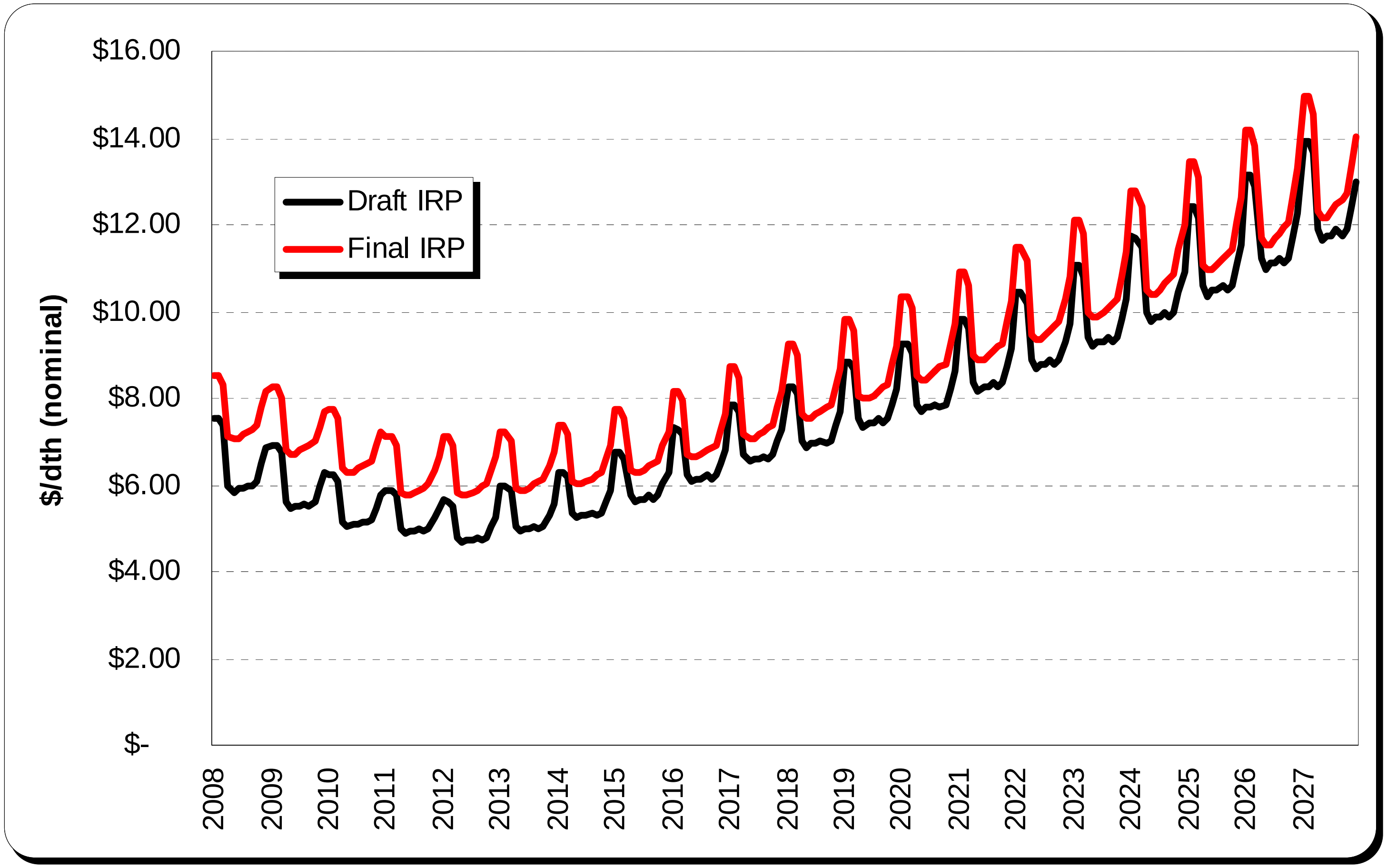
Basin Differentials/Gas Transportation



- Differentials are percent of Henry Hub, based on the average basin differential from a historical perspective
- Post-Kern River Pipeline Expansion - November 2003 to November 2006 period

We answer to you.

Draft IRP Gas Price Forecast vs Final Gas Price Forecast (levelized price increased from $7.47 to $7.83)



We answer to you.

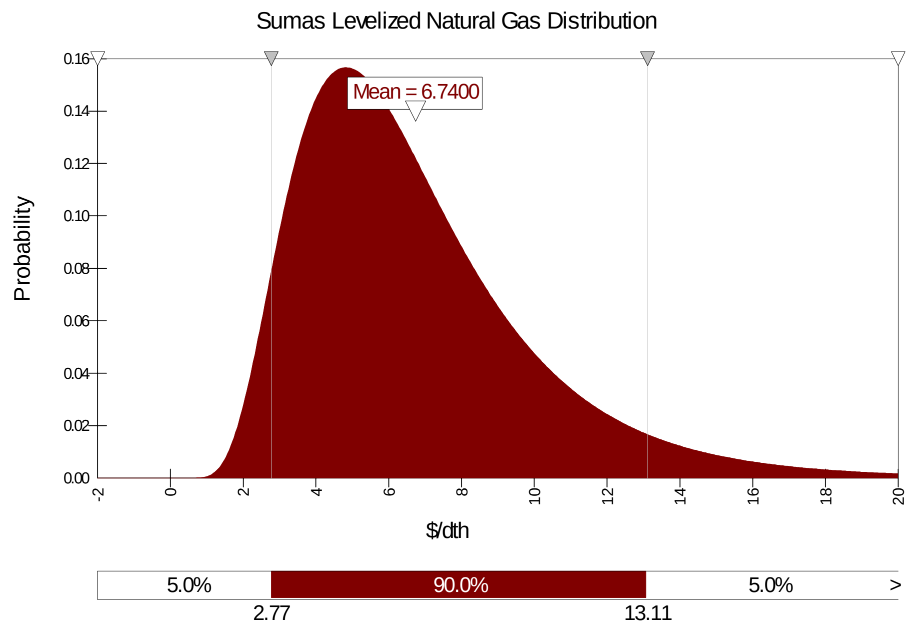
Other NW Utilities IRP Gas Price Methodology

- **Avista (2005):** Blend of Forward Prices and Global Insights
- **Avista Natural Gas (2006)**: Multiple scenarios utilizing forward prices and various consultants
- **Avista (2007):** Blend of Forward Prices and Consultant Forecast
- **Puget Sound Energy (2007):** Forward Prices and Global Insights
- **PacifiCorp (2006/07):** Forward Prices and PIRA
- **Idaho Power (2006):** weighted average of NYMEX, PIRA, EIA, NWPCC, and US Power Outlook
- **Portland General Electric (2006/07):** Forward Prices and PIRA

We answer to you.

Stochastic Natural Gas- Modeling Uncertainty

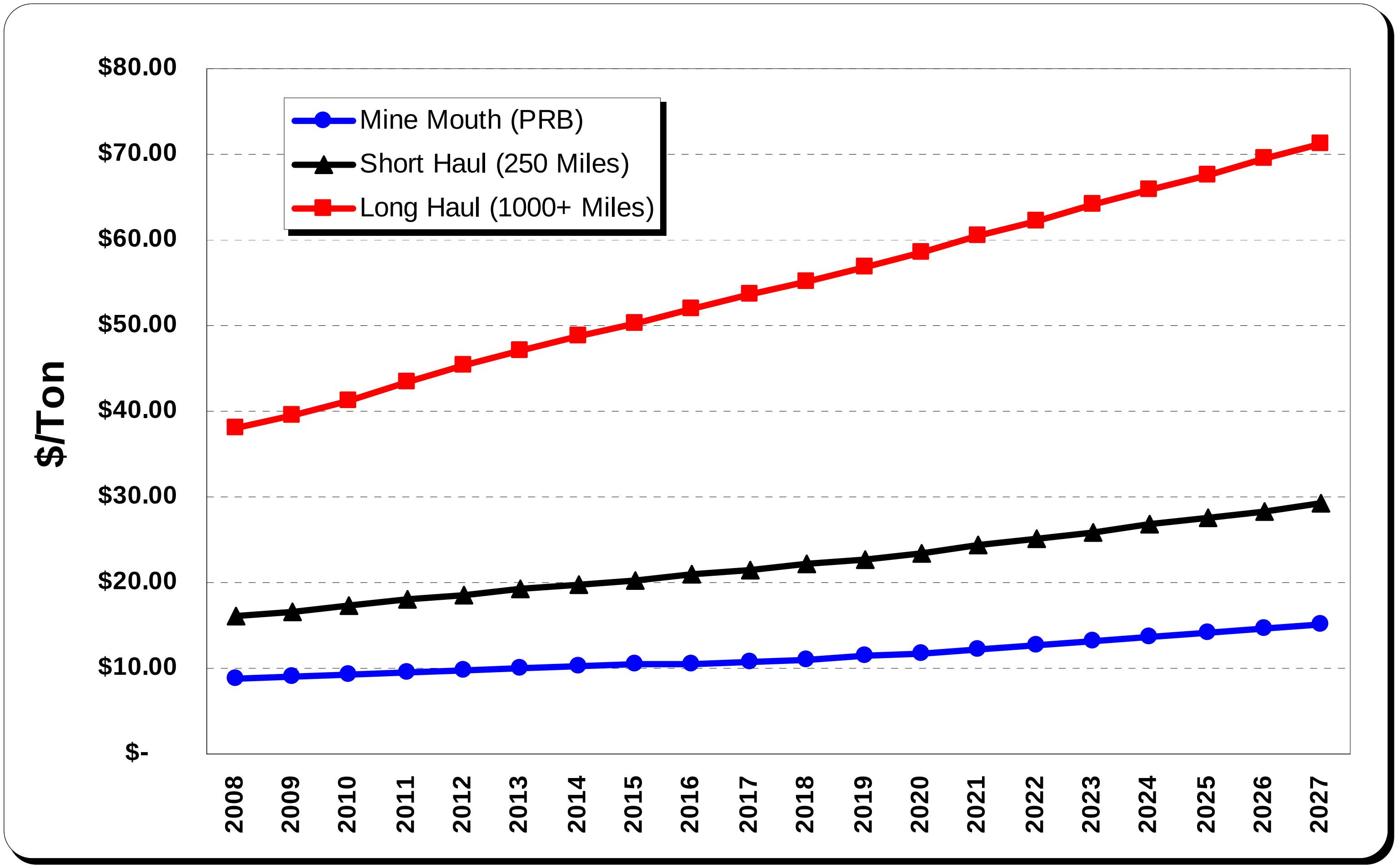
- 300 iterations, lognormal distribution drawn monthly with serial correlation (78%). The mean is the gas price forecast and the standard deviation is 50% of the mean.
- Another study will be performed using a higher/lower standard deviation



We answer to you.

AVISTA

Coal Prices



We answer to you.

AVISTA

Clean Coal Technologies

2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 10, 2007

John Lyons

We answer to you.

AVISTA

What is clean coal?

- "Clean coal technology describes a new generation of energy processes that sharply reduce air emissions and other pollutants from coal-burning power plants." – US DOE
- Clean coal technologies are aimed at increasing efficiencies and reducing sulfur dioxide (SO_2), nitrogen oxides (NOx), particulates, and greenhouse gases (mainly CO_2)
- There are four classes of clean coal technologies:
  - Precombustion technologies
  - Advanced combustion technologies
  - Postcombustion technologies
  - Conversion technologies
- Clean coal technologies come from several different disciplines and often result in multiple revenue stream possibilities, so more than electric generation needs to be considered

We answer to you.

AVISTA

Classes of Clean Coal Technologies

- Precombustion Technologies
  - Coal washing to remove ash, sulfur, and other impurities
  - Lowers costs of reducing SO_2 emissions as a combination technology
- Advanced Combustion Technologies
  - New technologies to retrofit or construct new pulverized coal plants
  - Atmospheric and pressurized fluidized bed combustion – reduce SO_2 95%
  - Higher pressures result in lower operating temperatures, smaller boilers, and higher generating efficiencies
- Postcombustion Technologies
  - Retrofits to the stacks of existing plants to remove SO_2 and NOx
  - Greatest potential for plants that have few current environmental controls
- Conversion Technologies
  - Technologies to convert coal into a gas or liquid fuel
  - Integrated Gasification Combined Cycle or IGCC

We answer to you.

Categories or Ranks of Coal

1. Lignite – soft with a high moisture content
   - 25 – 35% carbon and 4,000 – 8,300 btu/lb
2. Subbituminous – medium-soft with less moisture than lignite
   - 35 – 45% carbon and 8,300 – 13,000 btu/lb
3. Bituminous – medium-hard, low moisture and high heat value
   - 45 – 86% carbon and 10,500 – 15,500 btu/lb
4. Anthracite – hard coal, high carbon, low moisture & ash
   - 86 – 98% carbon and 15,000 btu/lb

We answer to you.

AVISTA

IGCC

- IGCC removes pollutants before they go up the stack
  - SO_2 and NOx is reduced by over 95%
  - Generating efficiencies increase 40 – 45%, which reduces CO_2 emissions
  - There are four operational plants, but the technology is still developing
  - IGCC has higher capital and O&M costs, which are partially offset by operating efficiencies
  - Can use petroleum residues, coal, or even biomass as a feedstock
- *FutureGen* is the $1 billion initiative to construct "the world's first zero-emissions fossil fuel plant"
  - 275 MW prototype to produce hydrogen and electricity with zero emissions
  - Will be first plant to capture and sequester CO_2
  - Selected sites in Illinois and Texas as the finalists for the project

We answer to you.

Carbon Capture and Sequestration

- Carbon capture refers to the technologies to keep CO_2 emissions from fossil fuel generation from being released into the atmosphere Sequestration is the long-term or permanent storage of the CO_2
- DOE programs are looking for technologies that are:
  - Effective and cost-competitive,
  - Stable and long term
  - Environmentally benign
- Sequestration is divided into geologic, ocean, terrestrial, and other categories

Geologic Sequestration

- Geologic sequestration involves pumping compressed CO_2 into the earth
- Several different types of geologic forms are well suited for geologic sequestration
- Oil and Gas Reservoirs
  - Can help recover oil or natural gas – which makes it a revenue stream
  - US uses about 32 million tons of CO_2 per year for enhanced oil recovery
  - Well understood, studied, and highly stable form of sequestration
- Coal Bed Methane
  - Inject CO_2 instead of pumping water out to depressurize the coal bed
  - Has been successfully field tested, but not commercially utilized yet
- Saline Formations
  - Pump CO_2 into deep saline formations which may store up to 500 billion tons of CO_2
  - Statoil is injecting approximately one million tons of recovered CO_2 into an underwater saline formation – equals the output of a 150 MW coal plant

We answer to you.

Ocean Sequestration

- Ocean sequestration uses the CO_2 absorbing power of the ocean
- Oceans can absorb 80 – 90% of atmospheric CO_2 but it takes a long time to transfer to the ocean depths
- Research into trying to speed this process in one of two ways:
  - Enhancement of the natural carbon sequestration of the ocean
    - 64 sq km region added trace iron and increased CO_2 levels
  - Direct Injection of CO_2 into the deep ocean

We answer to you.

Terrestrial Sequestration

- Terrestrial sequestration occurs when atmospheric CO_2 is stored in biomass or the soil
- Sequestration in soil or vegetation can handle about 1/3 of all human generated CO_2 or 2 billion tons of carbon annually
- Three general means of reducing GHG with terrestrial sequestration
  (1) Maintain existing carbon storage in trees and soils
  (2) Increase carbon storage by increased planting and improving tillage practices
  (3) Substituting bio-based fuels and products for fossil fuels

We answer to you.

Other Sequestration Technologies

- Advanced Chemical and Biological Approaches
- Recycling CO_2 with chemical or biological conversion
- May help eliminate the need to purify or compress the CO_2 for geologic sequestration, which uses more energy
- Genetic manipulation of plants and trees to enhance carbon sequestration potential
- Use of tubes of algae as a filter for CO_2 – algae is eventually turned into biodiesel
- Jupiter Oxygen is testing its Oxy-fuel technology on a $34 million retrofit of a small coal plant
  - Initial reports show a 95% CO_2 capture rate, 90% removal of all mercury, 99+% sulfur removal, 99+% particulate capture, more then 80% of the PM 2.5 particulate, and .088 Lbs/ MMBtu of NOx

We answer to you.

Emissions Update

2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 10, 2007

John Lyons

We answer to you.

Emissions Modeling in the IRP

Emissions cost included in the 2007 IRP Base Case:

- CO_2 – utilizing a distribution of NCEP, Climate Stewardship Act, and no legislation for each of the 300 draws
- SO_2 – $812/ton in 2007 and $2,717/ton in 2030 (nominal)
- NOx – $2,237 in 2010 and $4,127/ton in 2030 (nominal)
- Hg – $1,748/ounce in 2010 and $5,158/ounce in 2030 (nominal)

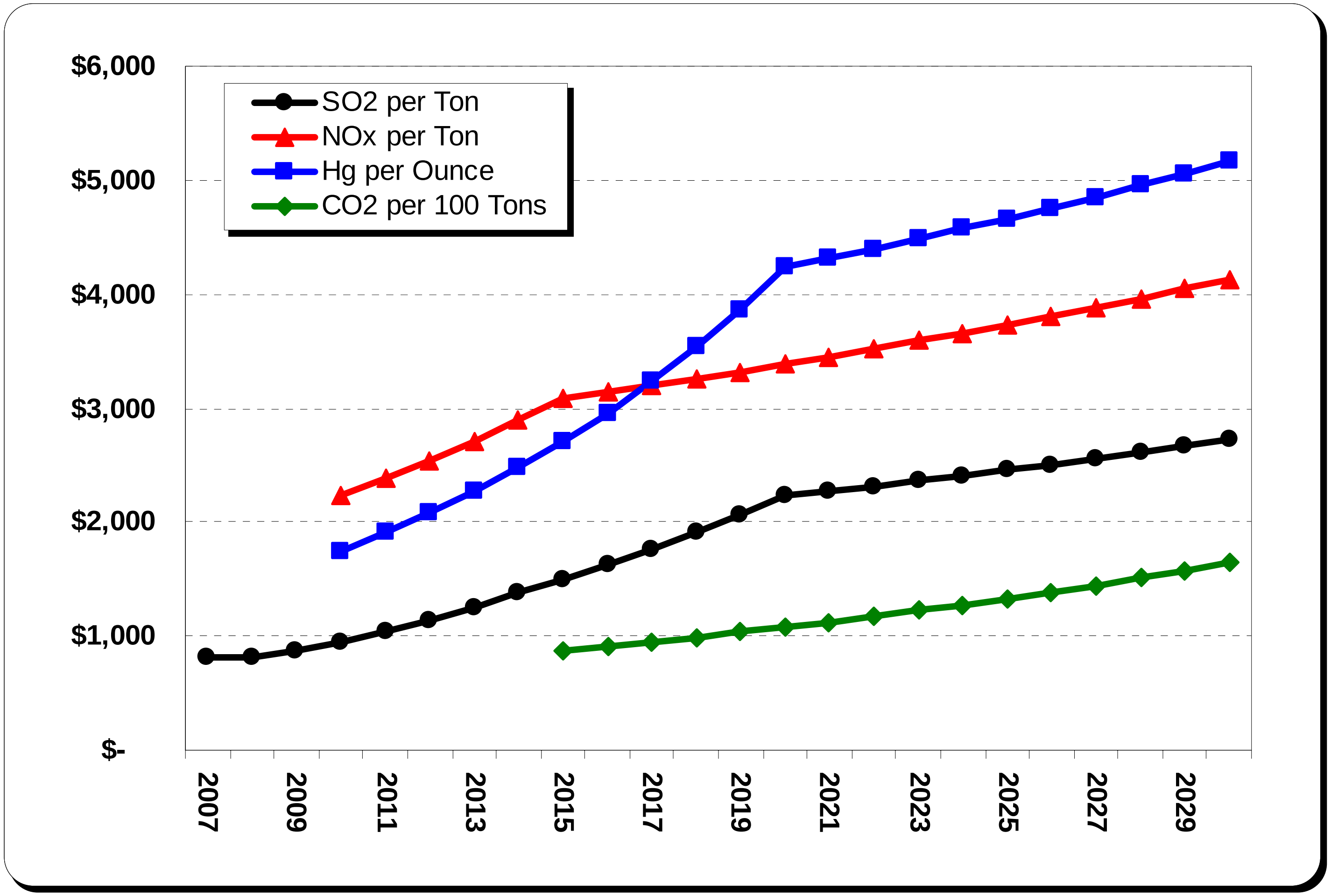
We answer to you.

Emissions Modeling

- Hg, SO_2, and NOx are being modeled using a log normal distribution

- CO_2 is being modeled based on a probability distribution for each of the 300 iterations:
  - 50% probability of NCEP
  - 15% probability of 25% below the NCEP
  - 15% probability of 25% above the NCEP
  - 10% probability of no CO_2 legislation
  - 5% probability of 50% of EIA/Climate Stewardship Act
  - 2% probability of 80% below the NCEP
  - 2% probability of 80% higher than the NCEP
  - 1% probability EIA/Climate Stewardship Act

Emission Costs – Nominal Dollars



National Emissions Developments

- Mercury Legislation
  - Clean Air Mercury Rule (CAMR) set permanent caps reduced and mercury reduction goals from coal-fired power plant emissions
  - CAMR allows for optional state participation in a national mercury trading allowance program
  - States are allowed to determine if allocations are granted or auctioned
- Proposed National Greenhouse Gas Legislation
  - Senator Reid has introduced S. 6, the National Energy and Environment Security Act of 2007
  - Promoting multiple energy ideas including risk reduction for global warming

Other Emissions Developments

- Joint Action Framework on Climate Change
  - Signed 12/1/06 by California, New Mexico, Oregon, and Washington
  - Provides for state PUC collaboration on energy efficiency, carbon capture & sequestration, and renewable energy
- Boulder, Colorado
  - First US tax specifically on carbon emitting fossil fuels
  - Adds approximately $1.33 to $3.80 to monthly electric bills
  - Funds are earmarked for investments in renewable energy, and efficiency improvements for buildings and transportation
  - Estimated to reduce GHG 7% below 1990 levels by 2012
- Northeastern Regional Greenhouse Gas Initiative
  - Develop a regional cap-and-trade program with a market-based emissions trading system
  - Will require electric power generators to reduce CO_2 emissions

We answer to you.

Washington Emissions Developments

- Mercury Legislation – Proposed
  - 0.0087 lb/GWh all sources in 2013
  - All plants must be compliant by 2017
  - Possible trading for the first 3 years
  - 70% to existing source, 5% new source, 25% supplemental

- Proposed Greenhouse Gas Legislation
  - Establish a greenhouse gas performance standard for base load fossil-fueled electric generation facilities before 7/1/08
  - 2004 CO_2 mitigation requirement for new generation is still in effect

Idaho Emissions Developments

- Mercury Legislation
  - Has no state budget for mercury under CAMR
  - Has decided not to participate in the cap-and-trade program.
  - Has reserved the right to opt in to the cap-and-trade program at a later date after assessing energy needs.
- Greenhouse Gas Legislation
  - Has no active GHG legislation

We answer to you.

Montana Emissions Developments

- Mercury Legislation
  - Montana Board of Environmental Review approved final adoption of the Montana Mercury Rule on 10/16/06
  - Established an emission limit of 0.9 lbs/TBtu for facilities using sub bituminous coal, and 1.5 lbs/TBtu for plants firing lignite, both on a rolling 12-month average
  - Temporary alternate emission limits can be applied for, but decrease in 2018
  - Requires a review of each plant every decade
  - Proposed new unit set-aside of 75% until 2018 and 30% thereafter.

- Greenhouse Gas Legislation - Pending
  - Montana Global Warming Solutions Act
  - 1/1/10 – identify, report, verify all sources of GHG emissions
  - 1/1/10 – determine 1990 emissions levels and set limit to be achieved by 2020
  - Set new recommendations before 1/1/19 for 2020 and beyond
  - 1/1/11 – identify "maximum technologically feasible and cost-effective reductions from sources or categories of source of greenhouse gases by 2020"

We answer to you.

Oregon Emissions Developments

- Mercury Legislation - Proposed
  - 90% or 0.60 lbs/TBtu by July 1, 2012 with possible one-year extension
  - Allowing for compliance alternative if targets are not met with best available controls
  - Four possible trading options under consideration

- Greenhouse Gas Legislation – in development
  - Oregon Strategy for Greenhouse Gas Reduction (December 2004)
  - Developing a detailed report by the end of 2007
  - Stabilize by 2010 – all GHG, not just CO_2
  - 10% below 1990 levels by 2020
  - 75% below 1990 levels by 2050

We answer to you.

California Emissions Developments

- Mercury Legislations
  - Considering a more stringent rule than CAMR

- Greenhouse Gas Legislation
  - AB32 – Global Warming Solutions Act: caps state CO_2 at 1990 levels by 2020 with enforceable penalties (~ 25% reduction)
  - SB1368 – CEC directed to set GHG standards for electricity produced within the state and purchases from outside of the state
  - SB107 – Investor owned utilities mandated to obtain 20% of power from renewables

We answer to you.

Avista Emissions Developments

- The core group of the Avista Climate Change Committee has been meeting on a consistent basis
  - Reviewing other organizations climate change policies
  - Writing a draft climate change statement
  - Designing a climate change section for our web site
  - Providing educational pieces to all employees in company newsletters

We answer to you.

AVISTA

Avista's 2007 Load Forecast

2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 10, 2007

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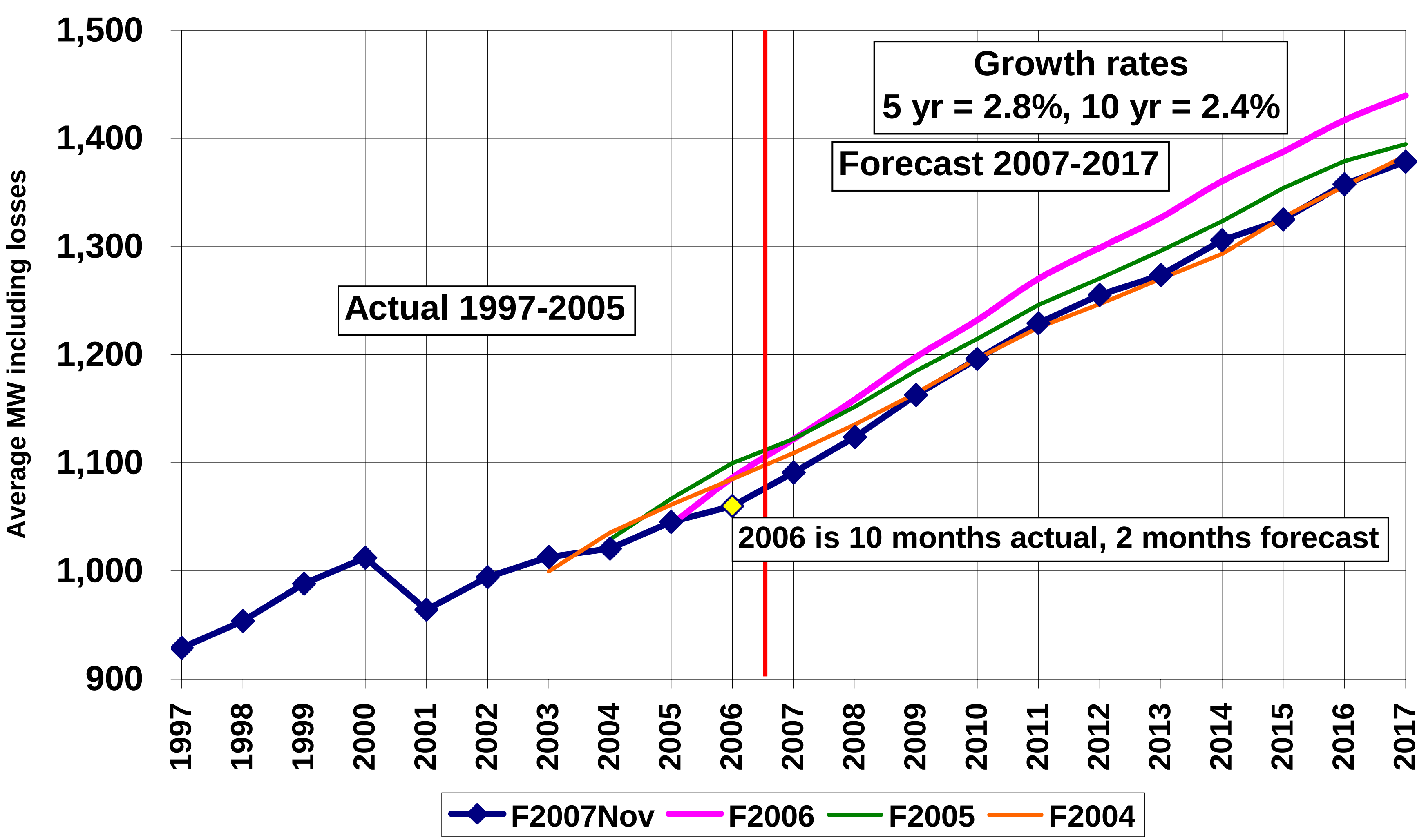
We answer to you.

AVISTA

Net Native Load



Native Load Forecast

Load (MW)	**F2007**	744	672	744	720	744	720	744	740	720	744	720	744
BOLD Actual	Annual Avg	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1997	**929**	**1,098**	**1,035**	**952**	**878**	**832**	**786**	**845**	**918**	**815**	**854**	**1,071**	**1,071**
1998	**954**	**1,065**	**994**	**943**	**902**	**941**	**845**	**966**	**936**	**866**	**886**	**960**	**1,140**
1999	**988**	**1,076**	**1,075**	**1,020**	**950**	**917**	**933**	**971**	**991**	**904**	**933**	**982**	**1,117**
2000	**1,012**	**1,153**	**1,114**	**1,034**	**921**	**889**	**924**	**961**	**985**	**889**	**950**	**1,163**	**1,173**
2001	**964**	**1,147**	**1,110**	**975**	**905**	**862**	**868**	**911**	**956**	**864**	**911**	**957**	**1,114**
2002	**994**	**1,095**	**1,072**	**1,040**	**929**	**898**	**950**	**1,018**	**953**	**891**	**968**	**1,034**	**1,090**
2003	**1,013**	**1,087**	**1,076**	**991**	**926**	**900**	**968**	**1,056**	**997**	**934**	**957**	**1,111**	**1,161**
2004	**1,021**	**1,194**	**1,108**	**987**	**925**	**900**	**963**	**1,037**	**1,023**	**926**	**964**	**1,072**	**1,157**
2005	**1,045**	**1,188**	**1,111**	**1,010**	**976**	**927**	**963**	**1,028**	**1,038**	**942**	**966**	**1,124**	**1,277**
2006	1,060	**1,159**	**1,199**	**1,092**	**966**	**962**	**987**	**1,102**	**1,045**	**959**	**1,000**	1,058	1,200
2007	1,091	1,266	1,198	1,147	1,008	970	987	1,057	1,089	994	1,063	1,087	1,230
2008	1,124	1,307	1,238	1,183	1,038	999	1,017	1,085	1,123	1,026	1,094	1,116	1,266
2009	1,163	1,354	1,280	1,224	1,076	1,034	1,051	1,121	1,163	1,064	1,132	1,152	1,308
2010	1,196	1,396	1,317	1,260	1,108	1,064	1,080	1,151	1,198	1,096	1,164	1,181	1,345
2011	1,229	1,438	1,354	1,296	1,140	1,093	1,110	1,180	1,231	1,128	1,195	1,211	1,381
2012	1,255	1,471	1,383	1,324	1,166	1,116	1,133	1,204	1,257	1,153	1,220	1,235	1,410
2013	1,274	1,493	1,403	1,344	1,183	1,133	1,149	1,220	1,275	1,171	1,238	1,252	1,430
2014	1,306	1,534	1,439	1,378	1,214	1,161	1,178	1,249	1,307	1,202	1,268	1,281	1,466
2015	1,325	1,558	1,460	1,398	1,233	1,178	1,195	1,266	1,327	1,221	1,287	1,298	1,487
2016	1,358	1,599	1,496	1,433	1,265	1,207	1,224	1,295	1,360	1,253	1,318	1,328	1,523
2017	1,379	1,625	1,520	1,456	1,285	1,226	1,242	1,314	1,381	1,273	1,338	1,347	1,546
2018	1,399	1,650	1,542	1,477	1,304	1,244	1,260	1,332	1,401	1,293	1,357	1,365	1,568
2019	1,426	1,684	1,572	1,506	1,331	1,268	1,284	1,356	1,428	1,319	1,383	1,390	1,599
2020	1,449	1,713	1,598	1,531	1,353	1,289	1,305	1,377	1,451	1,342	1,405	1,411	1,624
2021	1,477	1,748	1,629	1,560	1,380	1,313	1,330	1,402	1,479	1,369	1,431	1,436	1,655
2022	1,497	1,773	1,652	1,582	1,400	1,332	1,348	1,420	1,500	1,389	1,451	1,454	1,677
2023	1,518	1,799	1,675	1,605	1,420	1,350	1,366	1,439	1,521	1,409	1,471	1,473	1,701
2024	1,556	1,846	1,716	1,645	1,456	1,383	1,400	1,473	1,558	1,445	1,507	1,507	1,742
2025	1,582	1,879	1,745	1,672	1,481	1,406	1,423	1,496	1,584	1,471	1,531	1,531	1,771
2026	1,606	1,909	1,772	1,698	1,505	1,428	1,444	1,517	1,608	1,494	1,554	1,553	1,797
2027	1,626	1,934	1,795	1,720	1,525	1,446	1,462	1,536	1,629	1,514	1,574	1,571	1,820
2028	1,646	1,959	1,817	1,742	1,544	1,464	1,480	1,554	1,649	1,534	1,593	1,590	1,842
2029	1,674	1,994	1,848	1,771	1,571	1,489	1,505	1,579	1,677	1,561	1,620	1,615	1,873
2030	1,699	2,025	1,876	1,798	1,595	1,511	1,527	1,601	1,702	1,585	1,644	1,638	1,900
2007-2012 growth rate	2.8%	3.0%	2.9%	2.9%	3.0%	2.8%	2.8%	2.6%	2.9%	3.0%	2.8%	2.6%	2.8%
2007-2017 growth rate	2.4%	2.5%	2.4%	2.4%	2.5%	2.4%	2.3%	2.2%	2.4%	2.5%	2.3%	2.2%	2.3%
2007-2027 growth rate	2.0%	2.1%	2.0%	2.0%	2.1%	2.0%	2.0%	1.9%	2.0%	2.1%	2.0%	1.9%	2.0%

Native Peak Demand

Bold= Actual	Calendar	Operating Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1997	**1,508**		**1,508**	**1,391**	**1,286**	**1,228**	**1,115**	**1,019**	**1,202**	**1,289**	**1,122**	**1,146**	**1,403**	**1,373**
1998	**1,663**	**1,575**	**1,575**	**1,255**	**1,195**	**1,251**	**1,249**	**1,164**	**1,521**	**1,422**	**1,317**	**1,246**	**1,296**	**1,663**
1999	**1,434**	**1,663**	**1,357**	**1,379**	**1,300**	**1,209**	**1,213**	**1,338**	**1,405**	**1,402**	**1,175**	**1,232**	**1,308**	**1,434**
2000	**1,561**	**1,474**	**1,458**	**1,474**	**1,301**	**1,262**	**1,147**	**1,308**	**1,454**	**1,396**	**1,183**	**1,254**	**1,492**	**1,561**
2001	**1,490**	**1,561**	**1,474**	**1,490**	**1,329**	**1,209**	**1,243**	**1,228**	**1,382**	**1,370**	**1,169**	**1,175**	**1,380**	**1,429**
2002	**1,457**	**1,429**	**1,388**	**1,362**	**1,398**	**1,180**	**1,149**	**1,376**	**1,457**	**1,335**	**1,197**	**1,360**	**1,337**	**1,412**
2003	**1,509**	**1,457**	**1,393**	**1,408**	**1,258**	**1,221**	**1,179**	**1,321**	**1,487**	**1,400**	**1,332**	**1,323**	**1,432**	**1,509**
2004	**1,766**	**1,766**	**1,766**	**1,434**	**1,366**	**1,177**	**1,121**	**1,391**	**1,477**	**1,485**	**1,176**	**1,279**	**1,433**	**1,454**
2005	**1,660**	**1,563**	**1,563**	**1,409**	**1,270**	**1,246**	**1,123**	**1,367**	**1,495**	**1,473**	**1,207**	**1,239**	**1,466**	**1,660**
2006	1,656	1,660	**1,475**	**1,656**	**1,427**	**1,234**	**1,398**	**1,531**	**1,642**	**1,490**	**1,378**	**1,424**	1,392	1,571
2007	1,652	1,652	1,652	1,569	1,503	1,344	1,275	1,370	1,533	1,535	1,312	1,397	1,428	1,608
2008	1,703	1,703	1,703	1,618	1,549	1,383	1,311	1,407	1,568	1,579	1,352	1,436	1,465	1,653
2009	1,763	1,763	1,763	1,670	1,601	1,430	1,355	1,450	1,613	1,628	1,399	1,484	1,510	1,706
2010	1,815	1,815	1,815	1,716	1,646	1,471	1,392	1,487	1,651	1,673	1,439	1,523	1,547	1,753
2011	1,868	1,868	1,868	1,763	1,691	1,512	1,429	1,524	1,688	1,714	1,480	1,563	1,585	1,799
2012	1,909	1,909	1,909	1,800	1,726	1,543	1,458	1,553	1,717	1,747	1,512	1,594	1,615	1,835
2013	1,938	1,938	1,938	1,825	1,751	1,566	1,478	1,573	1,737	1,770	1,534	1,616	1,635	1,860
2014	1,989	1,989	1,989	1,870	1,794	1,605	1,514	1,609	1,774	1,810	1,573	1,654	1,672	1,905
2015	2,019	2,019	2,019	1,897	1,820	1,628	1,535	1,630	1,795	1,835	1,597	1,678	1,694	1,932
2016	2,070	2,070	2,070	1,943	1,864	1,668	1,571	1,667	1,832	1,876	1,637	1,717	1,731	1,977
2017	2,103	2,103	2,103	1,972	1,892	1,693	1,594	1,690	1,855	1,902	1,662	1,742	1,755	2,006
2018	2,135	2,135	2,135	2,000	1,919	1,718	1,617	1,712	1,878	1,928	1,687	1,766	1,778	2,034
2019	2,177	2,177	2,177	2,038	1,955	1,751	1,647	1,742	1,908	1,962	1,720	1,798	1,809	2,072
2020	2,214	2,214	2,214	2,070	1,986	1,779	1,673	1,768	1,935	1,991	1,748	1,826	1,835	2,104
2021	2,257	2,257	2,257	2,109	2,024	1,813	1,703	1,799	1,966	2,026	1,782	1,859	1,867	2,142
2022	2,289	2,289	2,289	2,137	2,051	1,838	1,726	1,822	1,989	2,052	1,807	1,884	1,890	2,171
2023	2,322	2,322	2,322	2,166	2,079	1,863	1,749	1,845	2,012	2,078	1,833	1,909	1,914	2,200
2024	2,381	2,381	2,381	2,219	2,130	1,909	1,791	1,887	2,054	2,126	1,879	1,954	1,956	2,252
2025	2,422	2,422	2,422	2,255	2,164	1,940	1,820	1,916	2,083	2,158	1,910	1,985	1,986	2,288
2026	2,460	2,460	2,460	2,288	2,197	1,970	1,846	1,869	1,966	2,085	1,940	2,013	2,013	2,321
2027	2,492	2,492	2,492	2,317	2,224	1,994	1,869	1,892	1,989	2,111	1,965	2,038	2,036	2,350
2028	2,523	2,523	2,523	2,345	2,251	2,019	1,891	1,914	2,012	2,136	1,990	2,062	2,060	2,378
2029	2,567	2,567	2,567	2,384	2,289	2,053	1,922	1,945	2,043	2,171	2,024	2,096	2,091	2,416
2030	2,606	2,606	2,606	2,419	2,322	2,083	1,950	1,973	2,071	2,203	2,054	2,125	2,120	2,451

2007-2012 growth rate 2.9% 2007-2017 growth rate 2.4% 2007-2027 growth rate 2.1%

Assumptions

- People, Jobs and Customers
  - Global Insight, Inc. Economic Forecasts
  - Spokane County and Kootenai County Trends
  - Customer Growth Projections
- Prices, Price Elasticity and Use per Customer
  - Electric and Natural Gas Price Forecasts
  - Own-Price, Cross-Price and Income Elasticity
  - Use per Customer Projections
- Sales Forecast
  - Small Customer Projections—Residential, Commercial and Industrial
  - Large Customer Projections—Manufacturing, Medical, Hospitality, Education and Governmental
- Conservation
- Weather Forecasts
  - NWS 1971-2000 Normal
  - Heating and Cooling Degree Days
- Scenarios

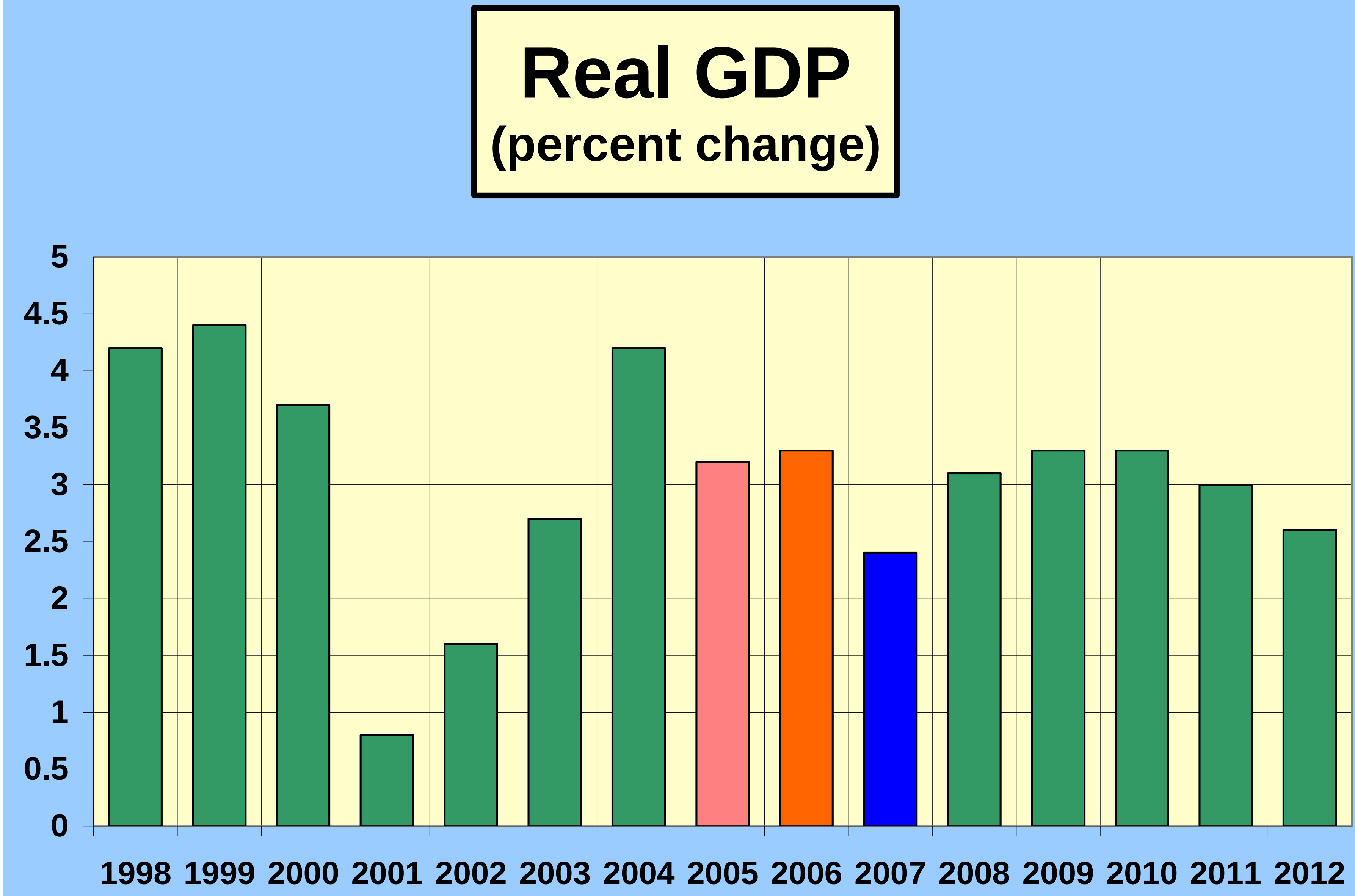
We answer to you.

AVISTA

National Economy

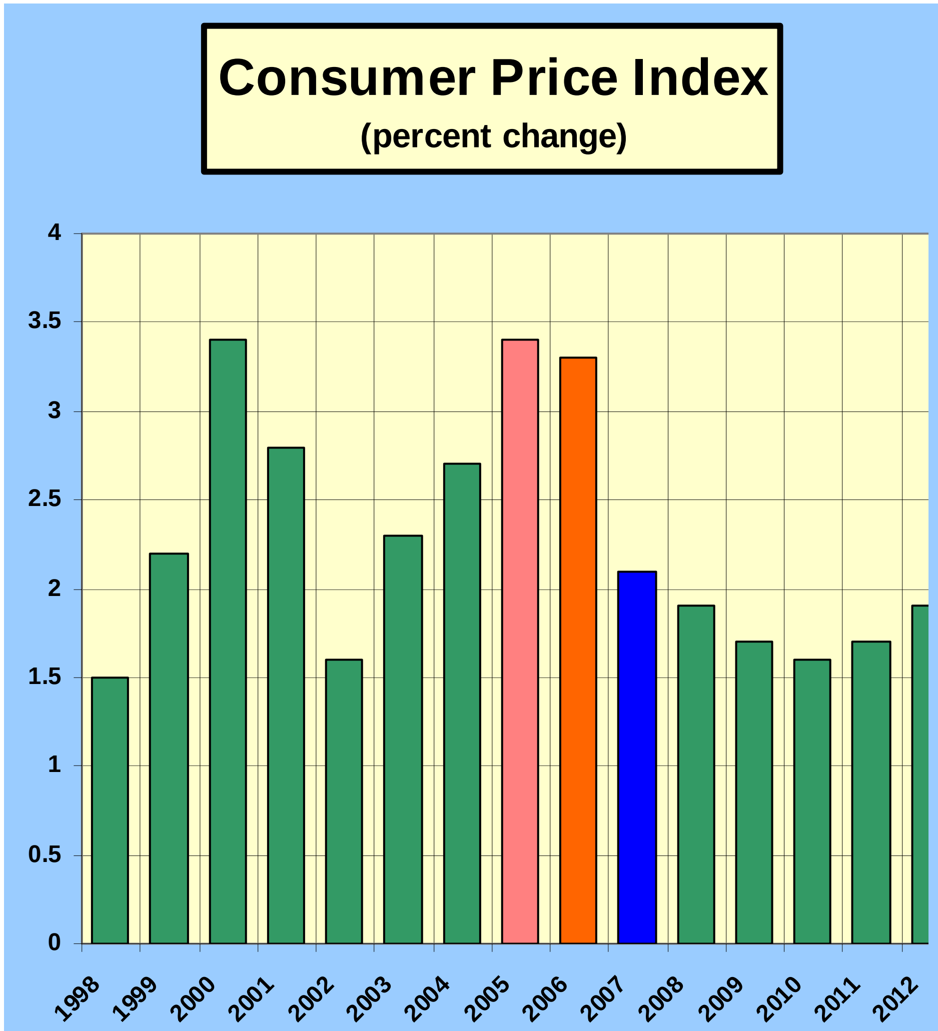
- U.S. Gross Domestic Product
- Consumer Price Index
- West Texas Intermediate Oil Price
- 10-year Treasury's Interest Rates
- U.S. Unemployment Rate
- U.S. Housing Starts
- U.S. Job Growth
- U.S. Productivity (Output per Worker)
- University of Michigan Consumer Sentiment

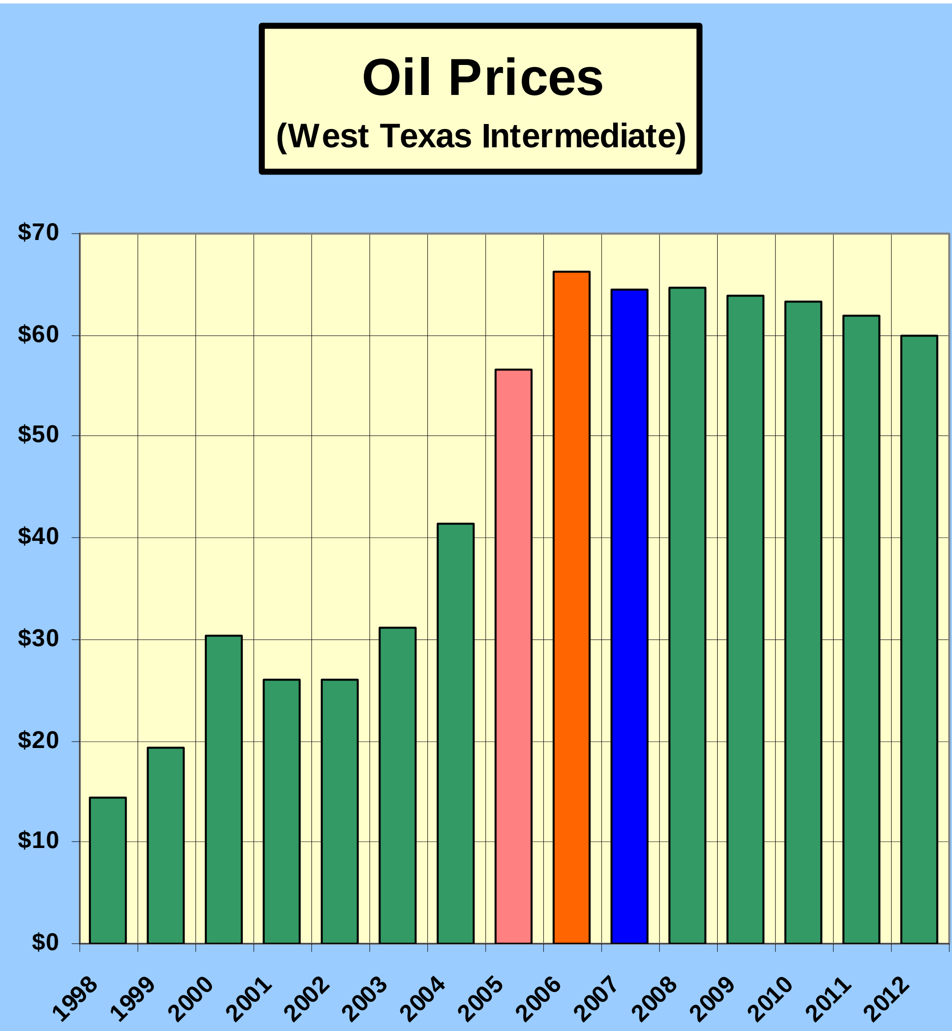
We answer to you.



We answer to you.

AVISTA





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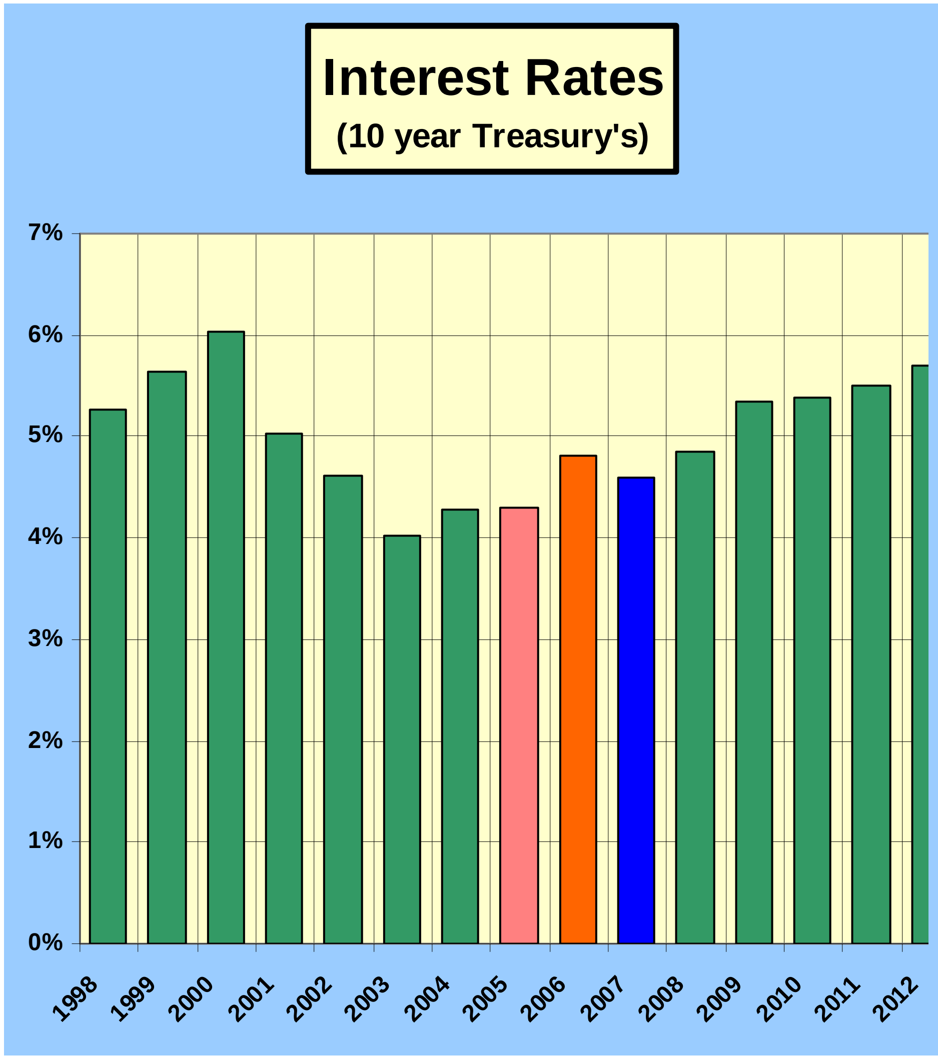
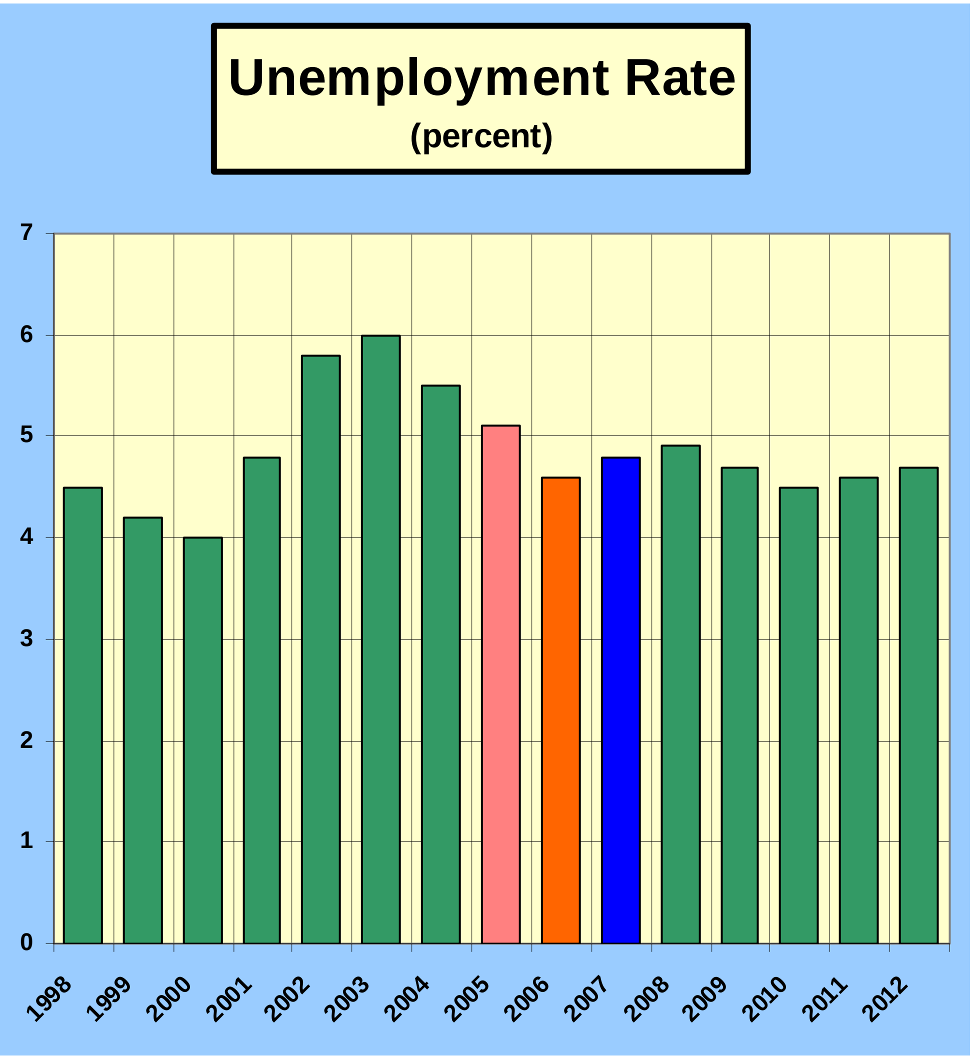
AVISTA





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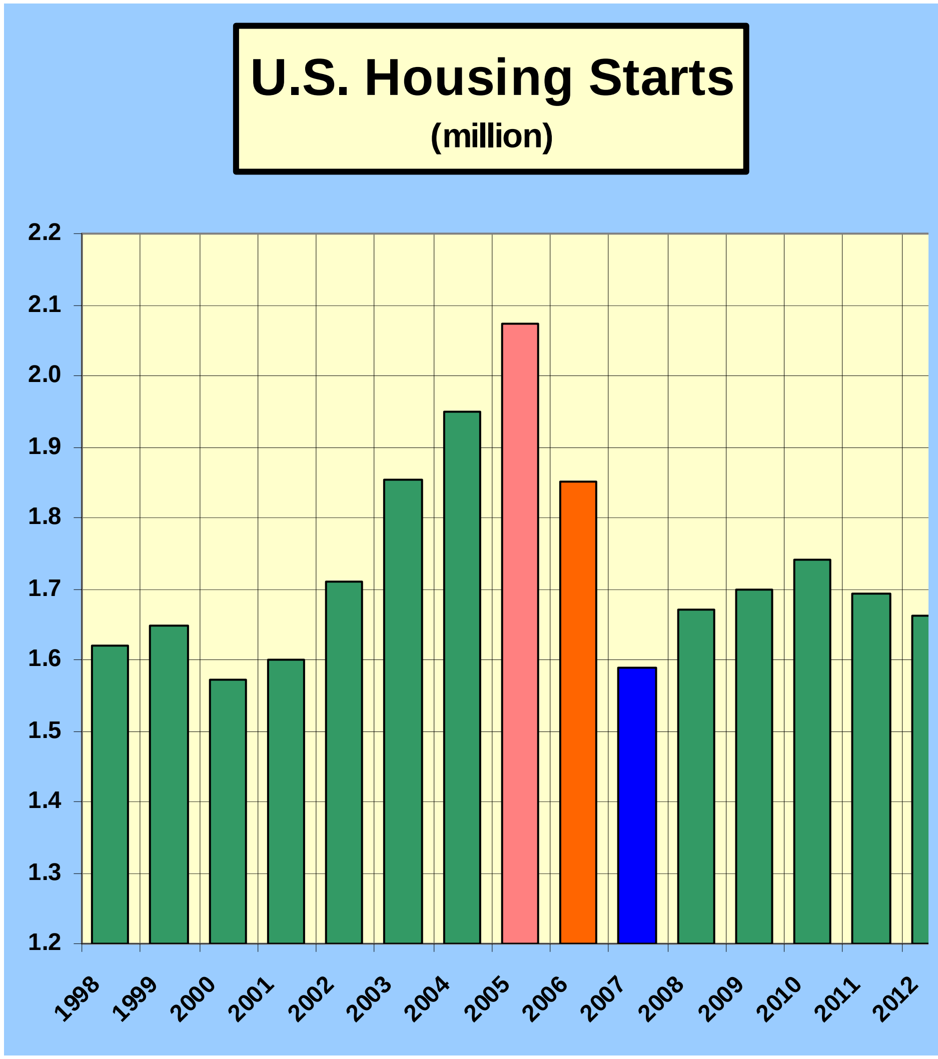
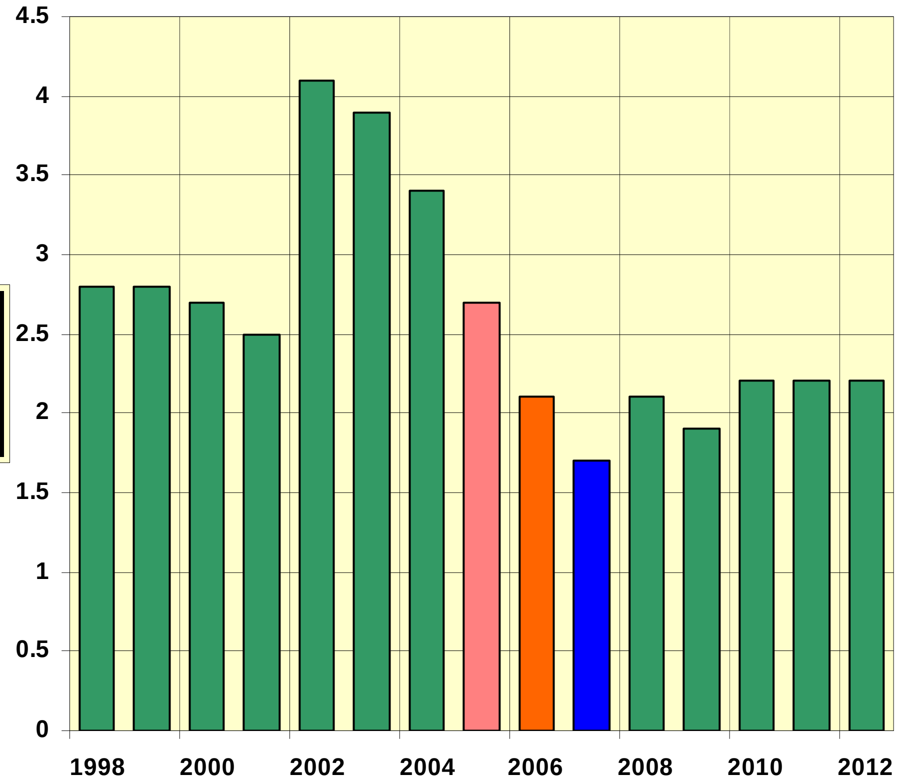


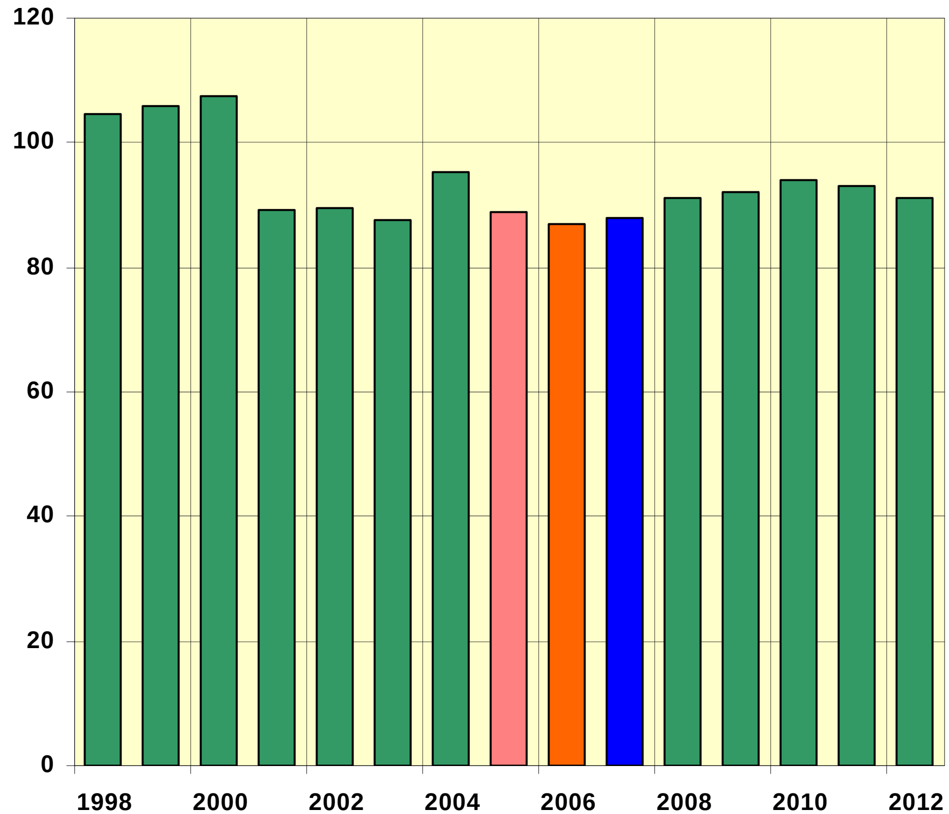
We answer to you.

AVISTA

Productivity
Output per Worker



Consumer Sentiment
University of Michigan



Regional Economy

- Global Insight County Forecasts
- Methodology
- Addressing acknowledgement shortcoming

- Both Idaho and Washington use Global Insight forecasts for various governmental planning efforts

We answer to you.

GLOBAL INSIGHT

Concept Coverage & Frequency

- 42 concepts & all 3111 Counties
- 2x a year (Spring/Jun & Fall/Dec)
- forecast: 30-yr of Annual data; most history: 1975

– Employment: 10 NAICS Supersectors
– Income: Average annual wage, total wage disbursements, & non-wage income (real & nominal)
– Demographics: Population, Households, and 10-year age categories for both

We answer to you.

Historical Data

GLOBALINSIGHT

- Employment – Global Insight creation off BLS Data
  - Monthly ES202, from BLS, with missing values filled-in
  - Data constrained to the monthly metro/states CES data, which is of higher quality
  - Lag: 9-12 months
- Income
  - Annual, from BEA
  - Lag: 1-2 yrs (currently thru 2004)
- Total Pop
  - Annual, from Census
  - Lag: 1-2 yrs (currently thru 2005q2)
- Households & Cohorts
  - Mostly from Census years

We answer to you.

Features/Goals of County Forecast

– All Counties Must Constrain to Metro Forecast (including non-metro portions of each state)
  - Ensures consistency with Metro/State forecasts
  - Takes advantage of higher-quality Metro/State forecasts, which have better, more reliable data and more advanced models
  - Cuts down on complexity of task

We answer to you.

Forecast Methodology Overview

GLOBAL INSIGHT

- Export Base Theory
  - Emp in Export/Base sectors → Emp in Nonbase/ Service Sectors → Income → Population → Demogs
- Mfg grown based on Cty's detailed sectoral composition (& corresponding state outlook)
- Most other sectors grown like state or a ratio of (concept/Pop or other concept) to state ratio
- Then, all constrained to MSA
- Pop Cohorts: Growth rates in cty cohort shares approach St growth rates in cohort shr over time
- HH Cohorts: Δ in Cty Headship rates by cohort moves like Δ in State headship rate

We answer to you.

AVISTA

GLOBALINSIGHT

Methodology: Details

- Base Emp: Mfg, Mining, Fed Govt, S&L Govt (if capital)
  - Mfg: EEMFG=EEMFG.1 * (generated ratio)^k.
  - Other Base sectors: Grow like State
- Nonbase Emp
  - Δ Cty NB = Δ Cty Base * (Δ State Base/ Δ State NB)
- Income:
  - Average Annual Wage: Grow like State
  - (Nonwage Income/WD) for Cty grown like same for St
- Population:
  - Δ Cty Pop = Δ Cty Emp * (Δ State Pop/ Δ State Emp)

- Lastly, Constrained to Metro

We answer to you.

Methodology: Details

GLOBAL INSIGHT

– Pop Cohorts:
  - Use cohort shares of total population
  - Ctyshr/Ctyshr.1 = (StShr/StShr.1) *

    (Growth in CtyShr between Census Pts)^[1/N] / (Growth in StShr between Census Pts),

    where N runs from 10 to 0 over 75 yrs

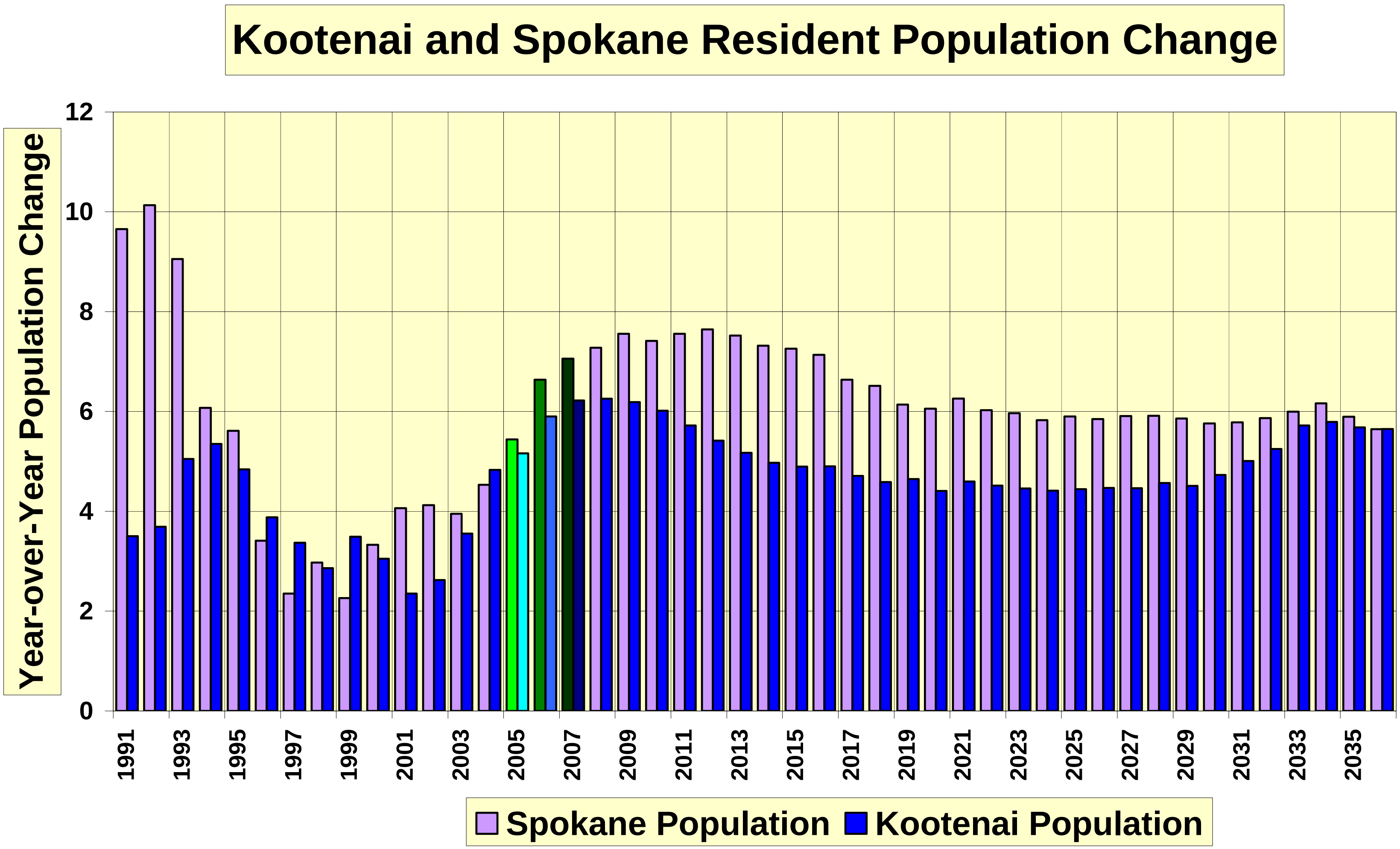
– HH Cohorts:
  - Headship rates by Cohort & Cty (HH Coh / Pop Coh)
  - Δ Headship for Cty Coh moves like Δ Headship for St Coh
  - Headship Rates * Pop → HH Cohort → Sum to Total HH

We answer to you.

Kootenai and Spokane County Forecasts

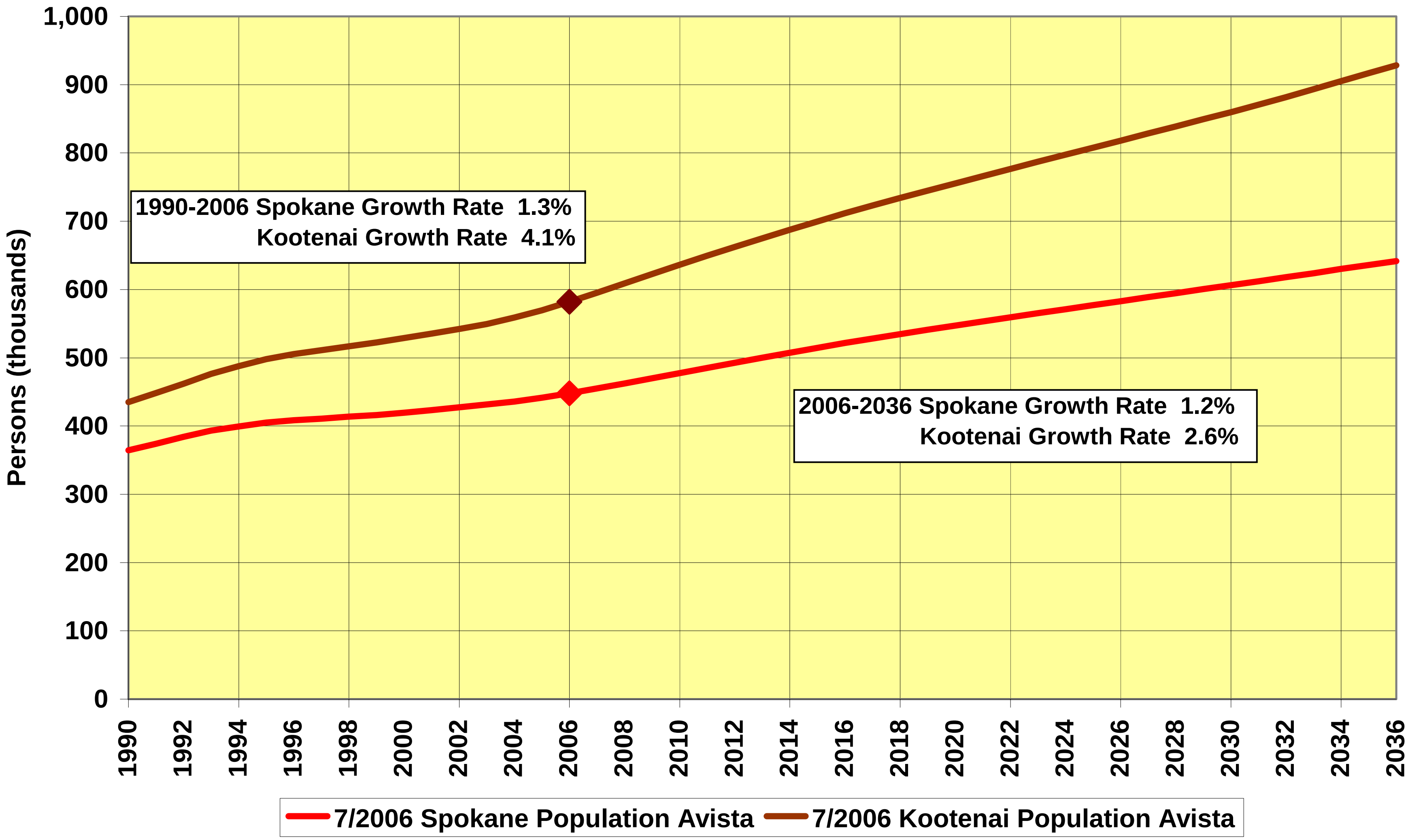
- Population Change
- Population Total
  - Service Area Population estimated at 875,000 in 2006
  - Kootenai and Spokane County Population 582,000 in 2006
  - Represents 66.5 percent of area served
- Employment Change
- Employment Total
  - Service Area Employment estimated at 359,000 in 2006
  - Kootenai and Spokane County Population 267,000 in 2006
  - Represents 74.4 percent of area served
- Recently subscribed to Global Insight forecasts for Gas IRP
  - Boundary, Shoshone, Latah, Nez Perce in Idaho
  - Stevens, Whitman, Asotin in Washington

Kootenai and Spokane County Population Trends



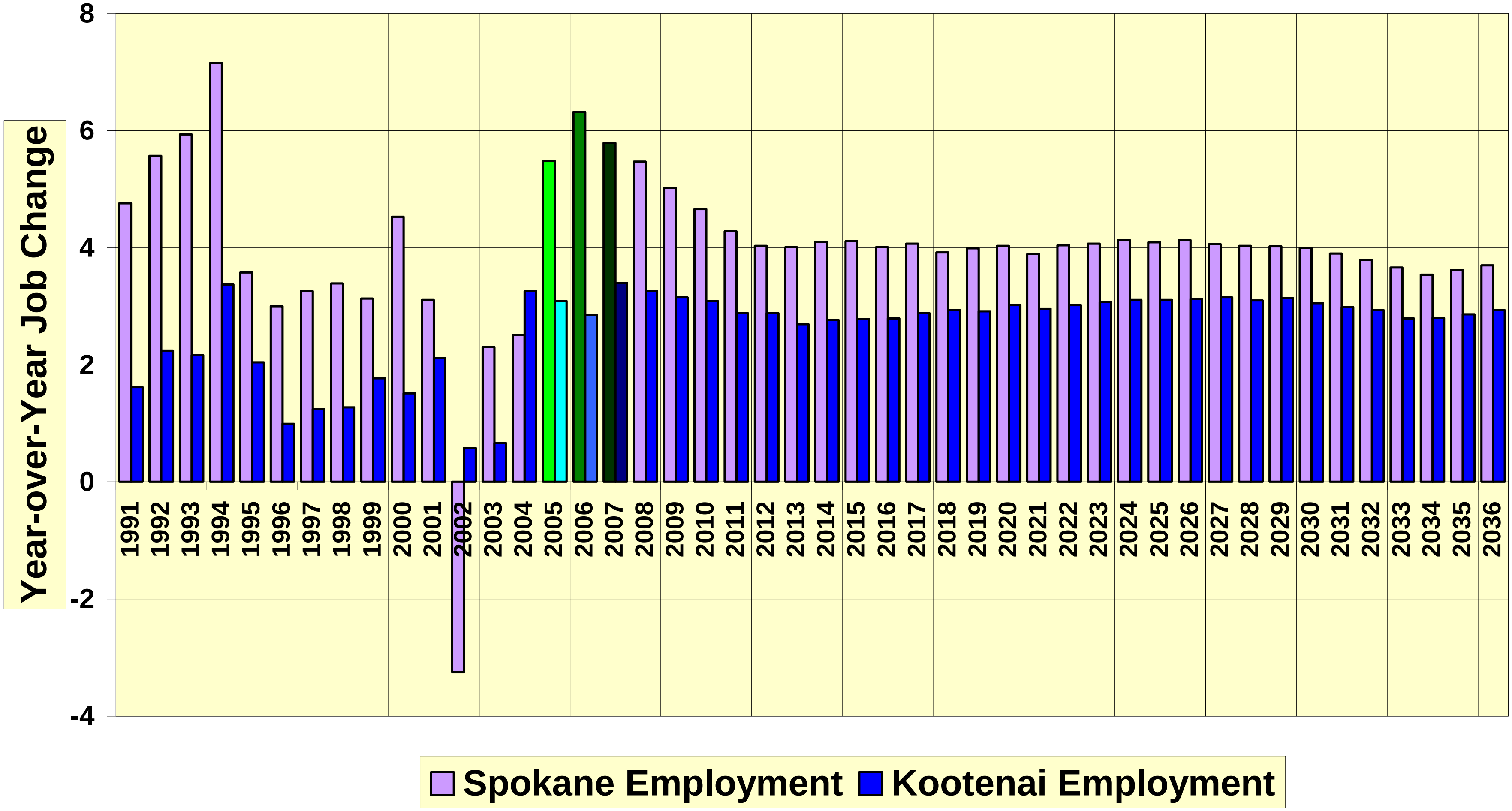
We answer to you.

Kootenai and Spokane Population Total

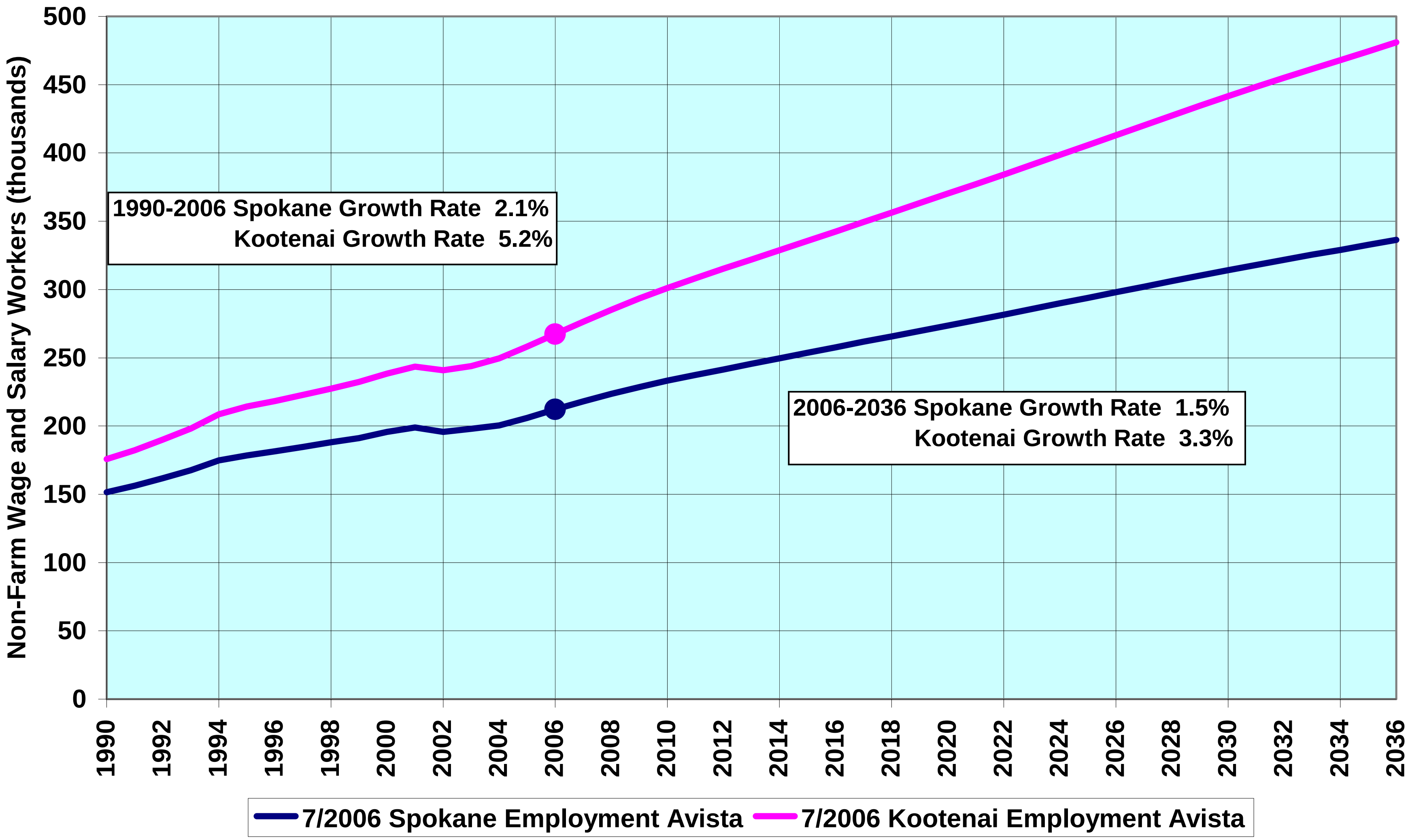


We answer to you.

Kootenai and Spokane Non-Farm Employment Change

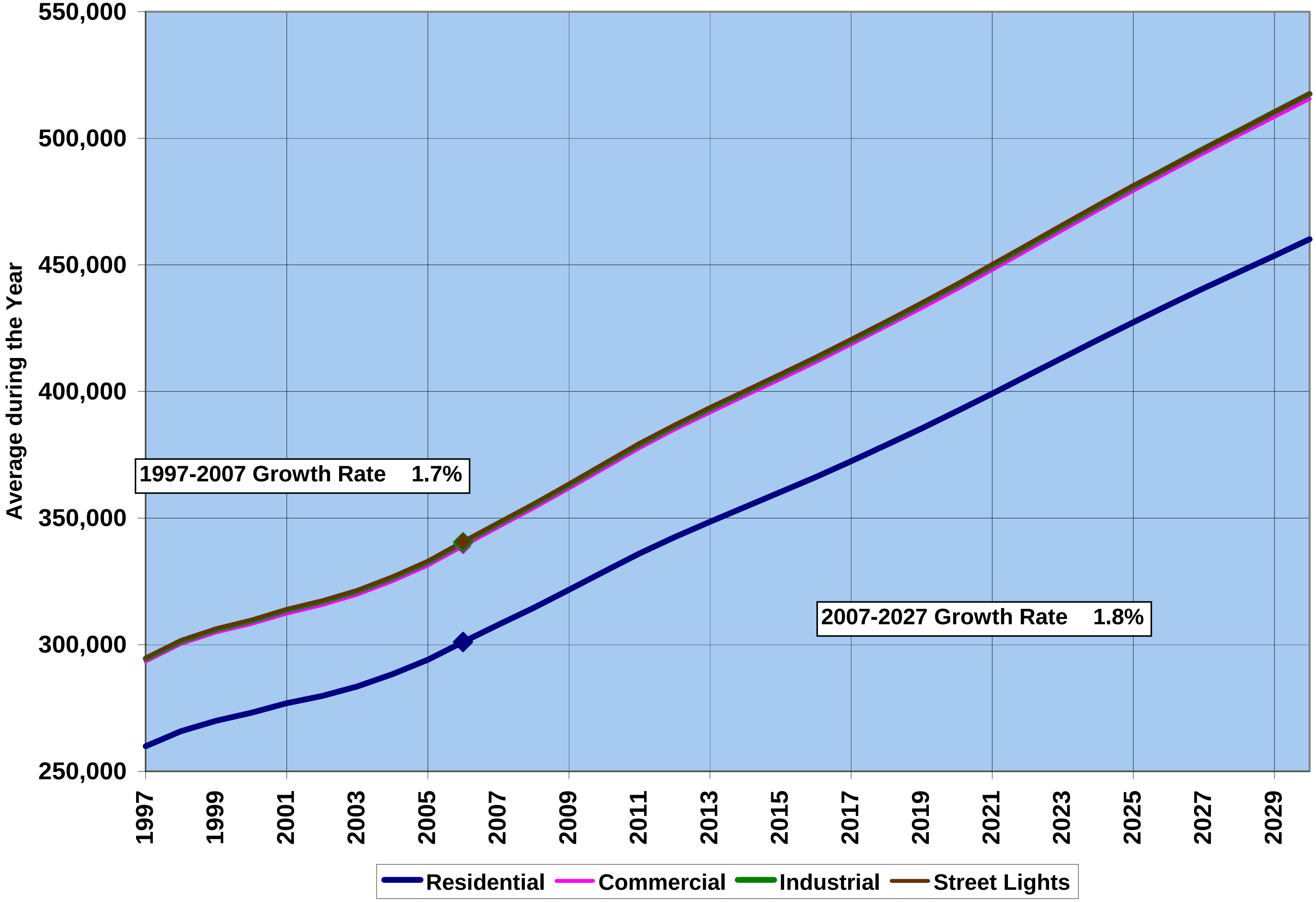


Kootenai and Spokane Job Total

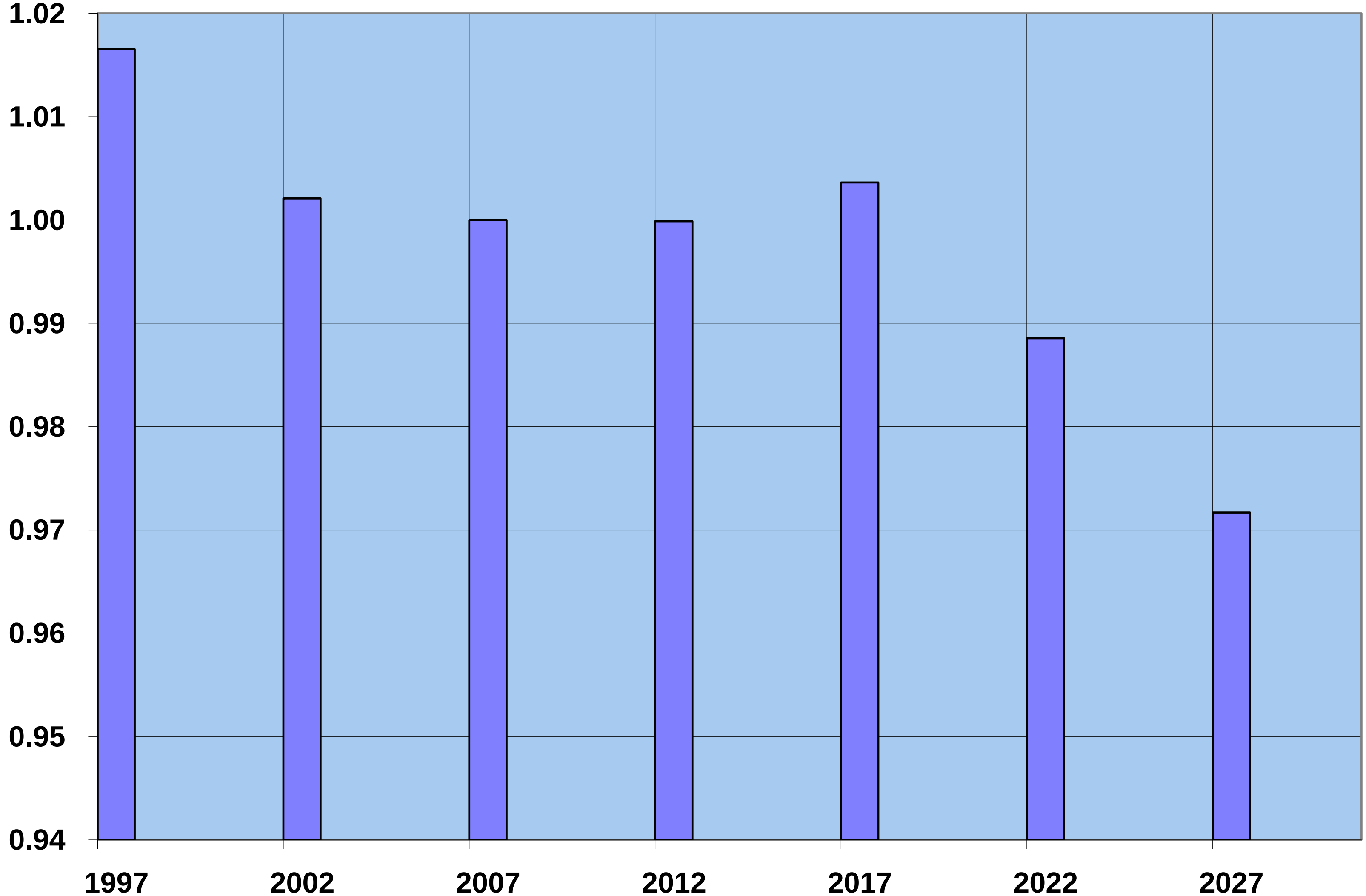


We answer to you.

Electric Customer Forecast—Base Case



Residential Customers—Index of Persons per Unit



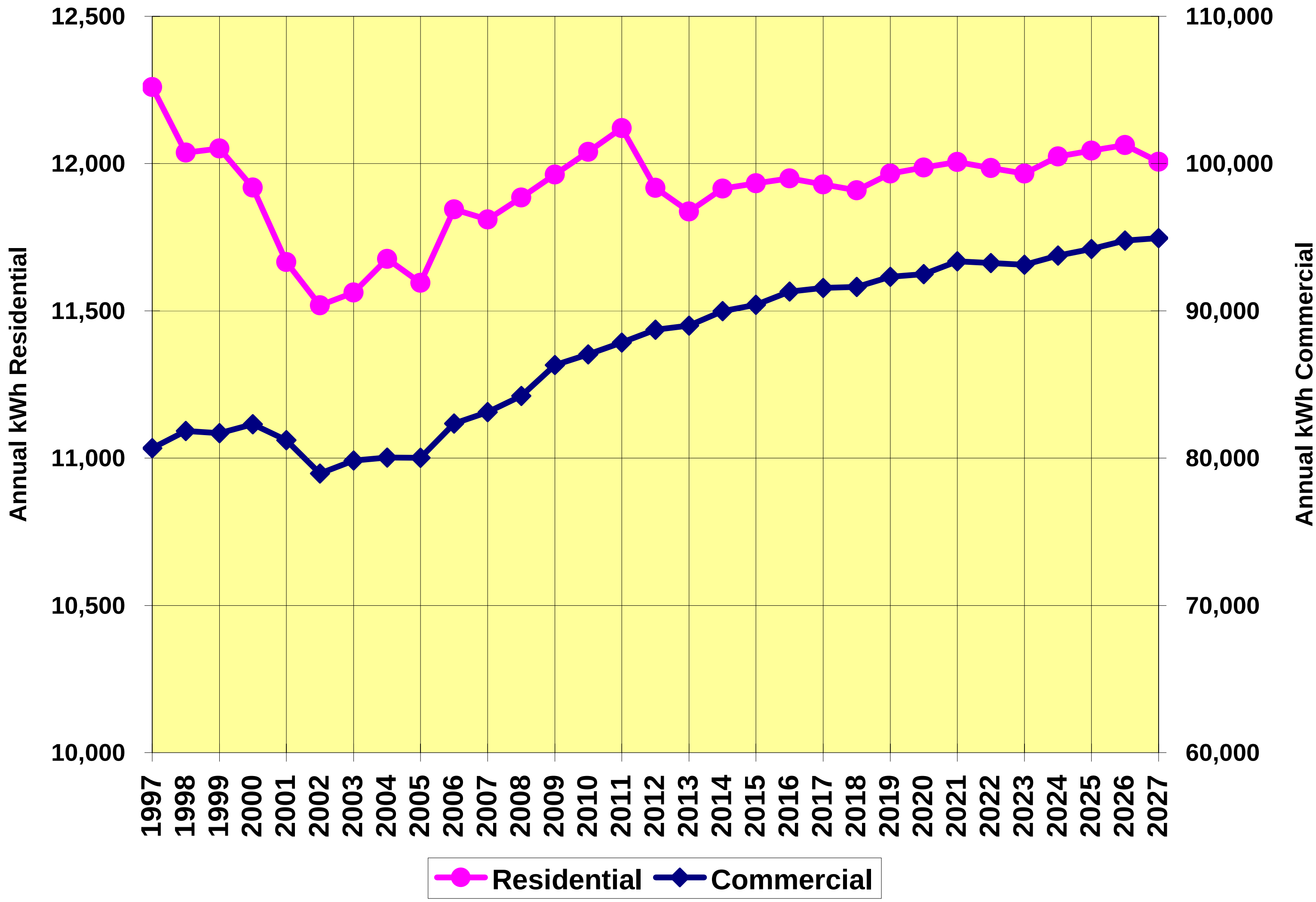
We answer to you. AVISTA

Prices, Price Elasticity, and Use per Customer

- Personal Consumption Deflator
  - 1997-2007 average compounded at 2.14 percent
  - 2007-2027 average compounded at 2.60 percent
- Electricity Prices (PRS from 2005 IRP)
  - 2007-2027 average compounded at 3.50 percent
  - Assume mid-year 17.5 percent rate increases every five years
    - Idaho in 2009, 2014, 2019, 2024
    - Washington in 2008, 2013, 2018, 2025
  - Impact is 5 percent above the rate of inflation
- Elasticity
  - -0.15 Electricity Price Elasticity (a 17.5 percent price increase is a real price increase of 14.9 percent, causing a 2.2 percent use decline, ceteris paribus)
  - +0.05 Cross Price Elasticity for Natural Gas
  - +0.75 Income Elasticity (makes electricity more affordable over time)

We answer to you.

Residential kWh Use Per Customer



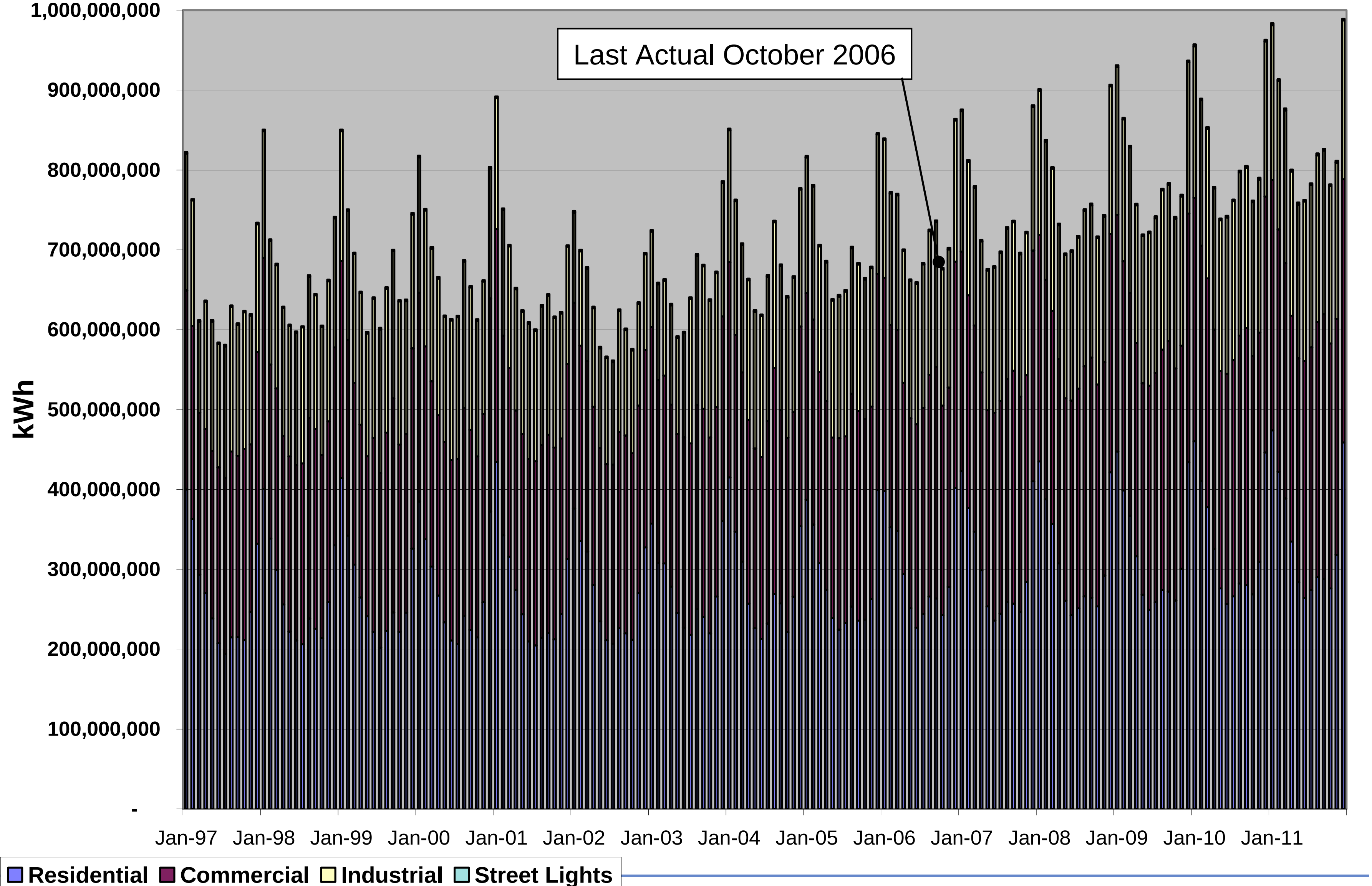
We answer to you.

Sales Forecasts

- Methodology
  - Bottom up forecast of customers and use per customer
  - By rate schedule for each State (Washington and Idaho)
  - Monthly for five years, annually thereafter
- Schedules
  - Schedule 1 – Small Residential
  - Schedule 11 – Small Commercial and Industrial
  - Schedule 12 – Medium Residential
  - Schedule 21 – Large Commercial and Industrial
  - Schedule 25 – Very Large Commercial and Industrial
  - Schedule 28 – Large Government Facilities
  - Schedule 30, 31, 32 – Residential, Commercial and Industrial Pumping
  - Schedule 41, 42, 43, 44, 45, 46, 47, 48, 49 Residential, Commercial and Industrial Area or Street Lights
- Roll Up Sales Forecast
- Results

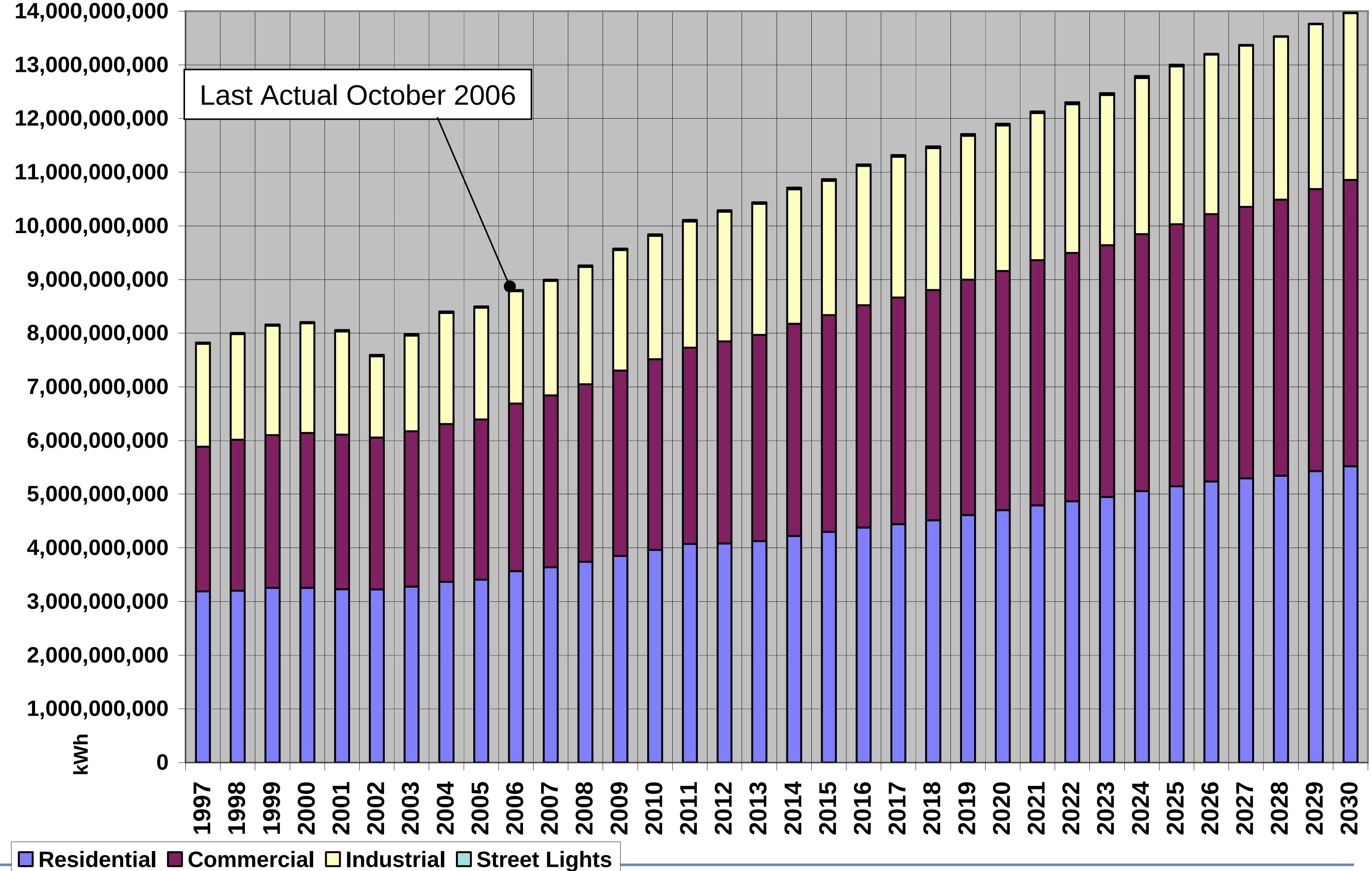
We answer to you.

Monthly Historical and Forecast Sales



We answer to you.

Annual Historical and Forecast Sales



We answer to you.

- Conservation
  - Codes and existing programs are included in the forecast
  - New programs are treated as “load serving” resources
- Weather Forecasts
  - The forecast uses normal temperatures from the 1971-2000 time period
  - Attempts to capture global warming impacts are not addressed
- Other Issues
  - Electric Cars
  - Natural Gas Retail Sales Interaction with Generation Cost Scenarios

We answer to you.

Scenarios

- **Avista's Natural Gas IRP Approach**
  - Vary customer growth for firm customers by plus or minus 50% from the base case
  - Considered the Medium High and Medium Low forecast in the context of the Northwest Power and Conservation Council's Plan
  - Large natural gas customers do not receive firm gas (only transportation) from Avista, and plan for their own supplies and deliveries
- Prior Approaches for Avista's Electric IRP
  - The 20-year growth rate of 2.0 percent was increased/decreased by 50%, resulting in a medium high growth rate of 3.0 percent, medium low of 1.0 percent
  - Optimistic and pessimistic economic long range economic forecasts were developed and used to produce alternative forecasts, although defining optimistic and pessimistic economic outlooks is controversial
  - Superimposing the Northwest Power and Conservation Council's Plan range of growth rates onto the base case sales forecast
- Avista is soliciting specific feedback from the TAC on a satisfactory approach

We answer to you.

Avista, DSM and the 2007 Electric IRP

Bruce Folsom & Jon Powell
2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 10, 2007

We answer to you.

Overview of the DSM Presentation

- The Past and Present of DSM within Avista *(Jon Powell)*
- The Reinvention of DSM *(Bruce Folsom)*
- Integrating Future DSM into the 2007 Electric IRP *(Jon Powell)*

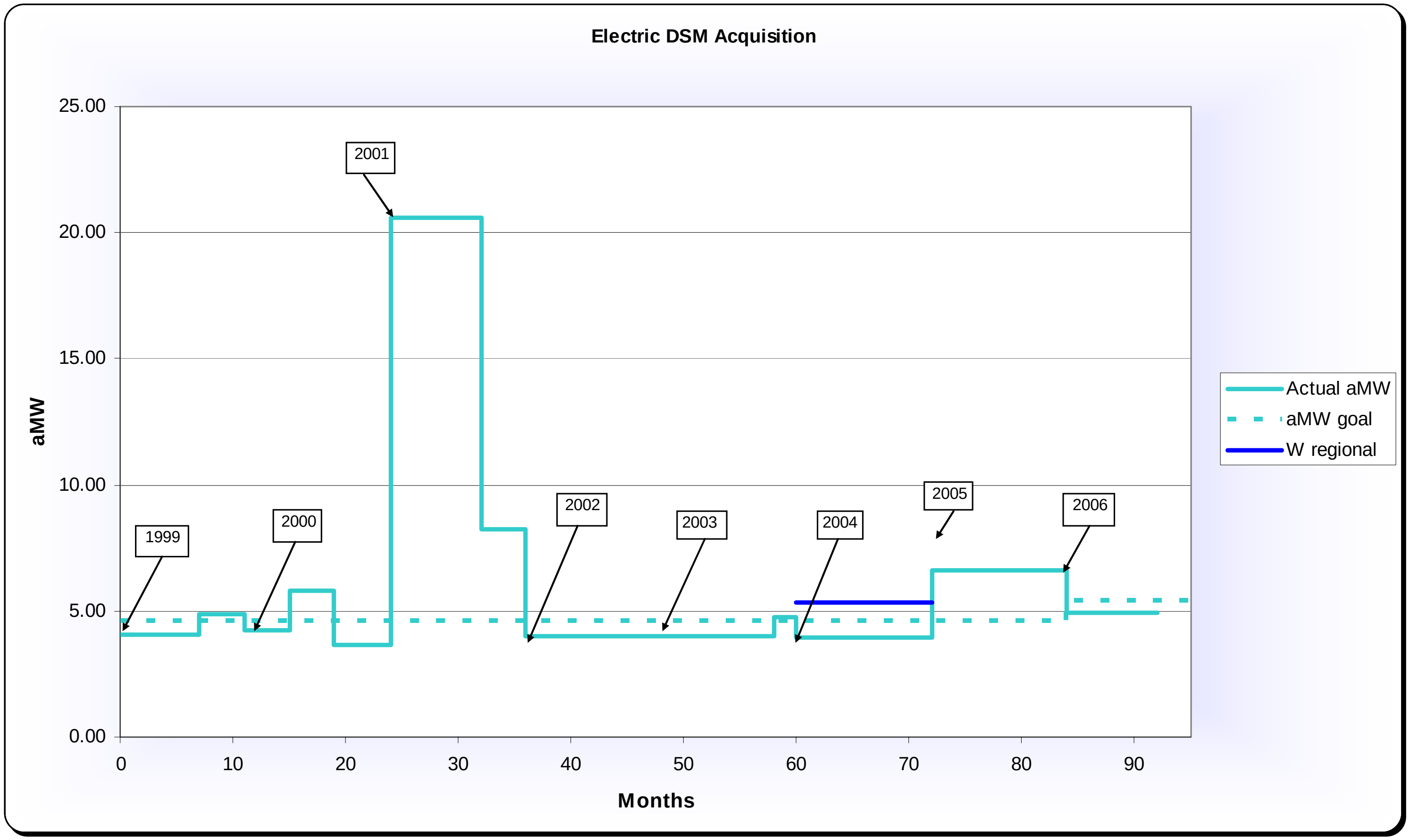
We answer to you.

A Historical Context for Avista DSM

- Electric DSM first offered in 1978
- 1992-1994 Energy Exchanger program
- 1995 approval of electric (and natural gas) DSM tariff rider
- 2001 Western Energy Crisis response
- 2002-2005 “lean and mean” business plan
- 2006 Reinvention of DSM

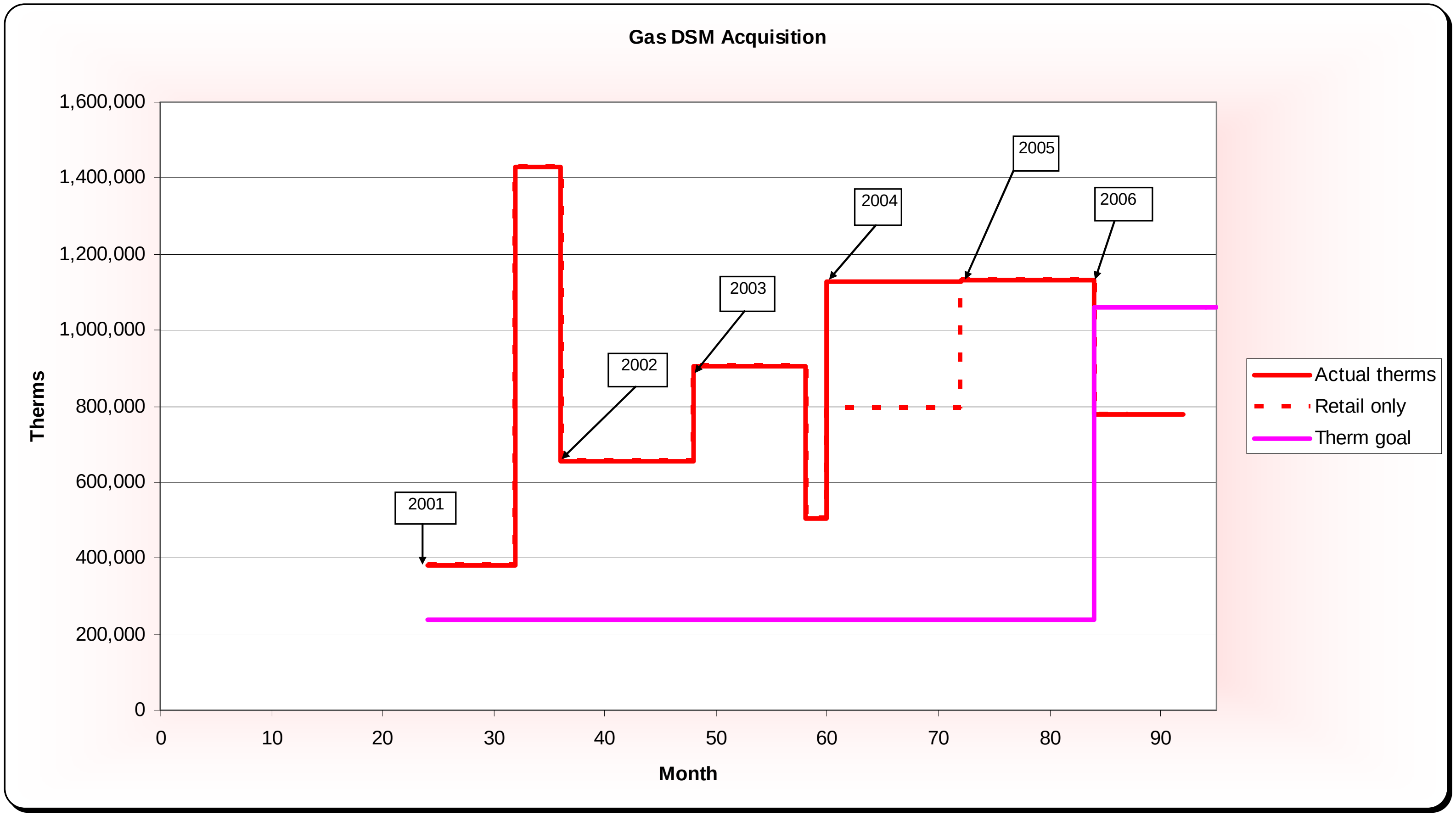
We answer to you.

Avista DSM Achievements



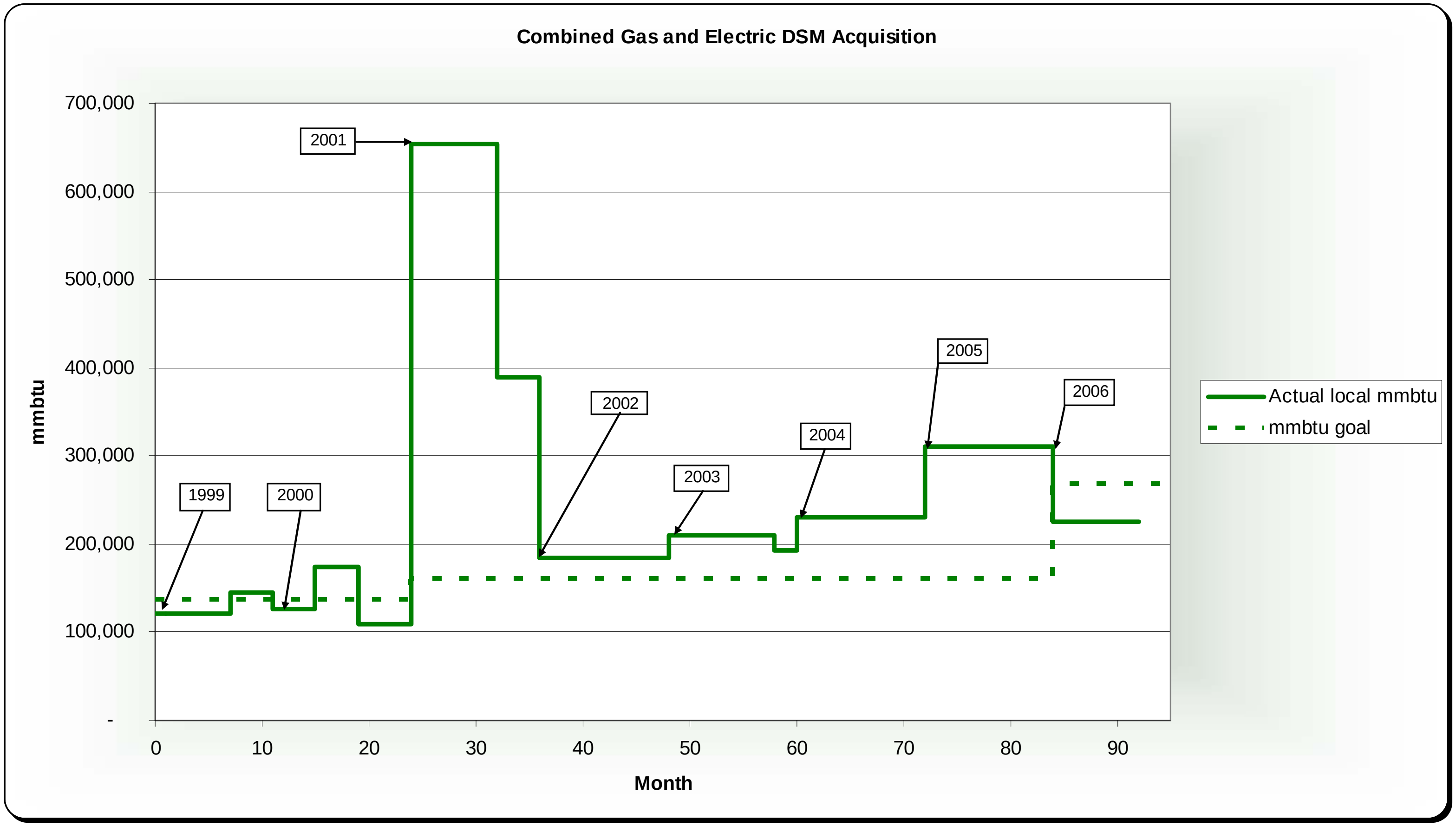
We answer to you.

Avista DSM Achievements



We answer to you.

Avista DSM Achievements



We answer to you.

Current DSM Funding

- Funding
  - DSM Tariff Riders (WA & ID, electric & natural gas)
    - Estimated 2007 WA revenue = $4.5 million
      - Residential $0.00127 / kWh , proportionate to other schedules
    - Estimated 2007 ID revenue = $2.1 million
      - Residential $0.00081 / kWh , proportionate to other schedules
    - 2007 WA/ID electric budget $9.1 million
      - $2.5 million in excess of revenue)
    - Projected 2007 tariff rider balances
      - WA negative $1.6 million to negative $3.8 million
      - ID positive $0.3 million to positive $0.0 million
    - Direct financial incentives to customers account for 78% of 2007 utility budget
    - Asymmetric interest provisions
  - BPA C&RD / CRC program
    - C&RD program $394k per year

We answer to you.

AVISTA

Current Organization of DSM Operations

- Three local portfolios + regional cooperative efforts
  - Non-Residential Portfolio
    - Site-Specific program
      - ANY EFFICIENCY MEASURE QUALIFIES
      - Incentive based upon a tiered incentive structure
        - » For projects with simple paybacks > 1 year
        - » 6, 10, 12, 14 and 4 cent / 1st year kWh for electric-efficiency
        - » 1 to 4 cents / 1st year kWh for fuel-efficiency
    - Prescriptive programs
      - Lighting, VFD's etc.
  - Limited Income Residential portfolio
    - Implemented through annual contracts with six CAP agencies
    - ANY EFFICIENCY MEASURE QUALIFIES
    - Additional provisions for health & human safety measures

We answer to you.

AVISTA

Current Organization of DSM Operations

- – Residential portfolio
  - • Exclusively prescriptive programs
    - – Weatherization, heat pumps etc.
- Avista Request for Information / Request for Proposals
  - – Business planning effort growing out of previous electric IRP
  - – → Early 2006 RFI
  - – → Early 2007 RFP’s
    - • Enhancements to commercial refrigeration efficiency programs (predominately electric)
    - • Enhancements to multifamily housing efficiency programs (electric and gas)

We answer to you. AVISTA

Current Organization of DSM Operations

- Regional portfolio
  - Northwest Energy Efficiency Alliance funding utility
    - Acquisition of electric-efficiency through market transformation
    - Funded by five IOU's, ETO, generating publics + BPA
      - » Avista funding = 4.0% of Northwest
    - Past acquisition at a TRC levelized cost of about 10 mills
      - » Not necessarily representative of future costs
    - Funding from DSM tariff rider for 1st ten years
      - » Currently funding NEEA through BPA CRC dollars
    - Significant and increasing overlap with local programs
      - » Local leveraging opportunities

We answer to you.

Oversight and Regulation

- External Energy Efficiency ("Triple-E") board
  - A response to increased tariff flexibility in 1999
  - Composed of regulators, customers, CAP agency representatives and other major stakeholders
  - Quarterly updates, spring & fall meetings, annual report
- Cost-recovery of DSM expenses
  - Prudence of DSM expenditures is incorporated into each GRC

We answer to you. AVISTA

Reinventing DSM

- Continuation of meeting traditional DSM challenges
  - Achieve the substantial increase in gas DSM acquisition goal
  - Establish the infrastructure necessary for long-term operations
  - Obtain sufficient funding to maintain near-zero balances on each of the four individual tariff riders.
- Participate in the Northwest response to changes in electric markets and how they effect the viability of regional programs
- Expand the horizons of “DSM” to include all approaches to non-generation resource management

We answer to you.

Starting Point for Expanded Initiative

- Track record of innovation
- Energy efficiency programs among best in the country
  - 1992-1994 – “The Energy Exchanger Era”
  - 1995-2000 – “The Tariff Rider Era”
  - 2001 – “The Year of the Western Energy Crisis”
- A Demand Response Team that has…
  - Strong technical skills
  - Excellent people-to-people attributes
- Company-wide experience and expertise in utility operations

We answer to you.

Demand Response Is…

- Energy efficiency

<u>AND…</u>

- Critical peak pricing (i.e., peak shaving)
- Peak shifting
- Time-of-use pricing
- Credits for large customers who have pre-established contracts
- Seasonal pricing
- Voltage control
- Distributed generation and cogeneration
- Transmission and distribution (T&D) efficiencies
- All other

We answer to you.

Benefits

- Customer benefits
- More information for large resource acquisition decisions
  - National and state policy: emission requirements
  - Technology: pulverized coal, IGCC, nuclear
- Reduced pressure on, or alternatives for, capital budget
- Potential cost savings

We answer to you.

Alignment of "Processing" and Analyses

- Power supply analysis starts with a resource and its portfolio fit:
  - Hydro
  - Baseload thermal
  - Renewables
  - Peaking facilities
- Demand response also starts with a resource and portfolio fit:
  - Energy efficiency
  - T&D efficiencies
  - Time-of-use pricing (daily and seasonal)
  - Peak shaving (critical peak pricing & bilateral customer contracts)
  - Real-time pricing

We answer to you.

Alignment… (continued)

- Enterprise-wide
  - Most departments will have potential to contribute
  - Three states – two fuels
- Not bounded by all-or-nothing…break into pieces
  - Schedule 25
  - Scalable and learning from examples (ours and others)
- Full examination of all ideas
  - Scrutinize recognizing that we have paid $250/mwh at times
- Timing will differ for varying assessments and roll-outs
  - Peak-shaving in place for next summer

We answer to you.

Demand Response Initiative:

- Maintain focus on targets and existing DSM programs while
  - assessing best practices status
  - surveying and implementing expanded options
- Continue the Company's legacy:
  - resource acquisition through least-cost demand response programs
  - innovate on customers' behalf

We answer to you.

Demand Response Initiative (continued):

- Acquire sufficient energy and demand savings to delay a thermal plant as long as cost-effective
  - through a comprehensive, state-of-the-art demand response initiative
  - by examining and implementing:
    - expanded energy efficiency programs,
    - peak shaving programs,
    - consideration of time-of-use schedules,
    - and all other options (e.g., T&D efficiency),
  - in a manner that is sustainable and fiscally credible

…pursue the most efficient portfolio (supply and demand response) that we can possibly deliver

We answer to you.

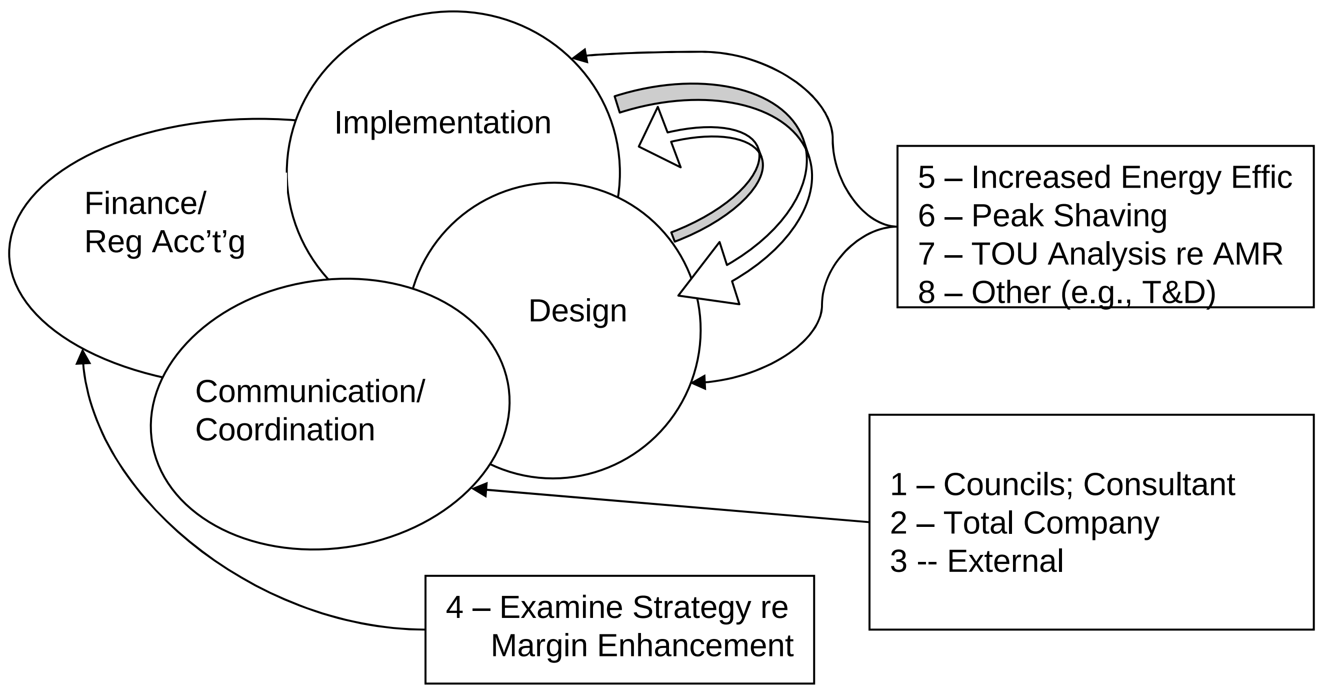
AVISTA

Potential Change in Regulatory Treatment

- Washington Electric General Rate Case, consider:
  - -- Capitalizing (may also need Accounting Order, in advance)
  - -- Allowance for Funds Used Conserving Energy
  - -- One-way Balancing Account
  - -- In the alternative, increase Schedule 91 and 191
- Has the effect of increasing budget, as appropriate
- Request finding of prudence per Schedule 91 requirement

Coordination and Iteration

Figure 1



Some Key Activities

- Assessments
  - Review all potential energy efficiency programs <u>and</u> delivery options
  - Survey industry best practices
  - Survey all demand response programs with segmentation by typ
- Communication and coordination
- Milestone establishment and monitoring

We answer to you.

Integration of DSM into the 2007 IRP

Objective:

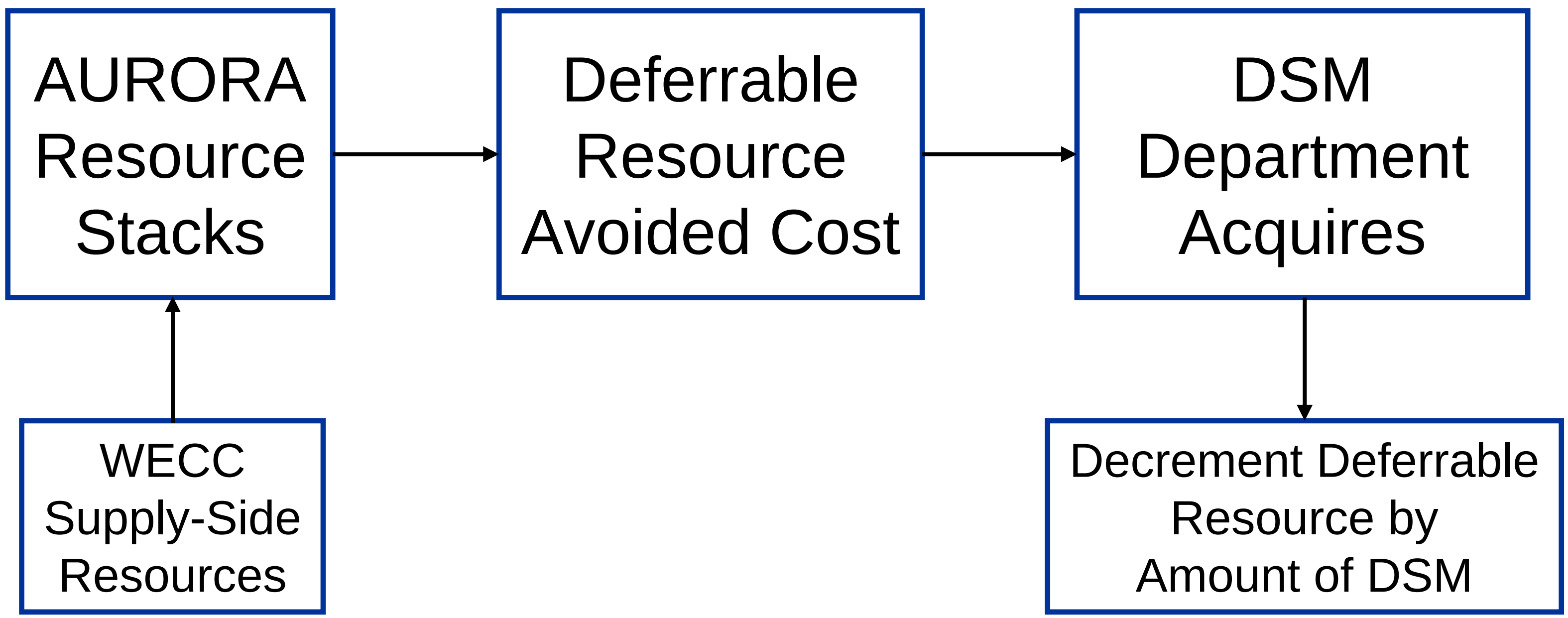
- This should not be a purely academic effort or merely to meet regulatory requirements – it should be part of our resource and business planning process
  - Identify potential non-residential technologies and applications to target
    - "Acceptance" or "rejection" within the IRP will not remove any technology or application from potentially being included in our non-residential portfolio
  - Re-evaluate residential measures in our current portfolio and evaluate the introduction of additional measures
    - The IRP evaluation will lead to a process that could change our menu of qualifying residential measures
  - Establish an acquisition goal that will assist us in
    - Budget projections & tariff rider revenue planning
    - Infrastructure needs to include labor complement

We answer to you.

Integration of DSM into the 2007 IRP

- Avista's approach to incorporating DSM into the IRP:

Integration by Price Signal



We answer to you.

Why this works … and when it doesn't

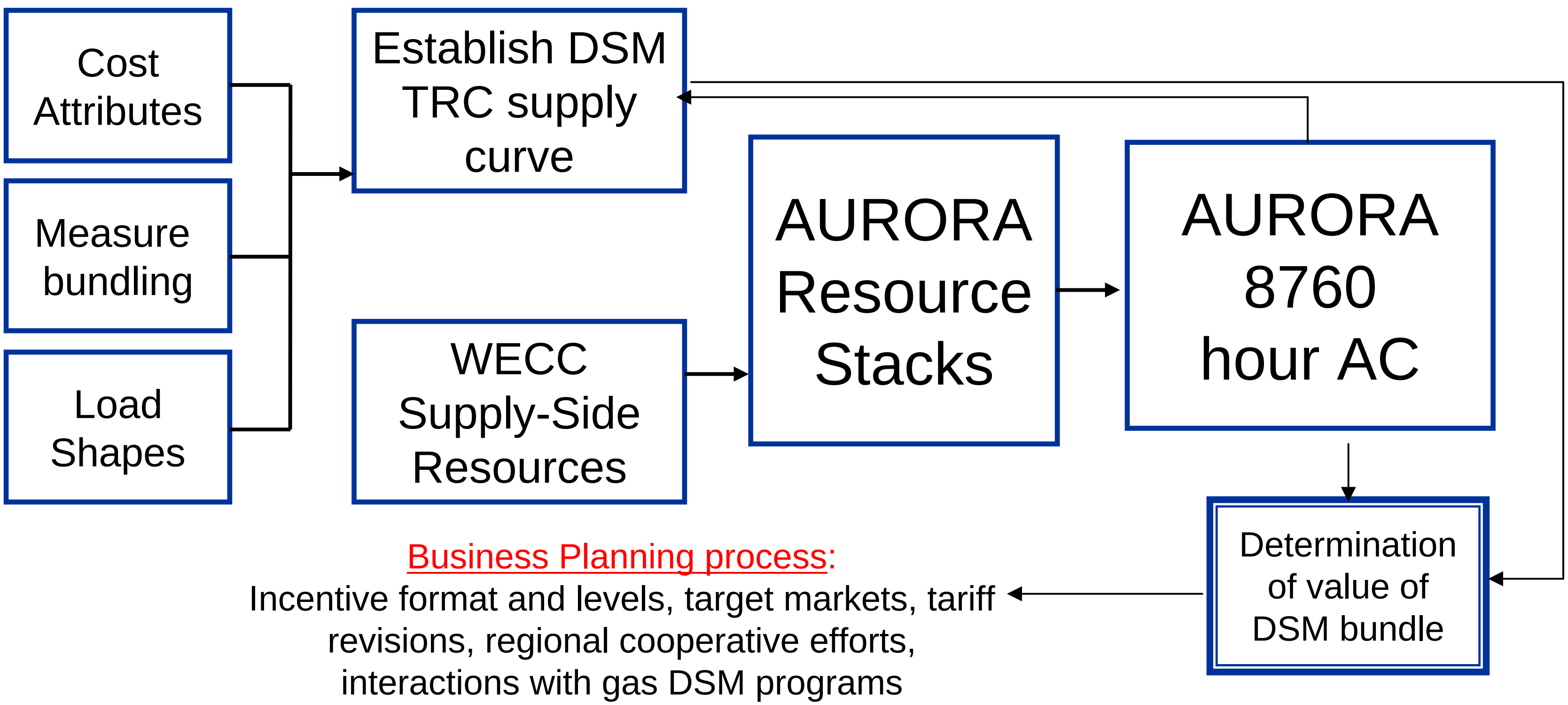
- DSM is acquired in small annual amounts relative to the size of the overall load requirement
  - This does not preclude having a large amount of DSM online through the 'snowballing' effect over time
- DSM is non-dispatchable (historically)
  - Evaluation of potential exceptions to this approach will be evaluated as appropriate
- The non-interactive nature allows the Company to continually modify and test new opportunities between IRP's in a manner consistent with the most recent IRP.

We answer to you.

Challenges of Integrating DSM

- Our much richer avoided cost stream (8760-hour detail as opposed to a single annual avoided cost) is more demanding of our load research capabilities
- The lack of a demand-response component to our Schedule 90 (DSM) tariffs limit our ability to either
  - Pursue cost-effective peak-shifting opportunities
  - More aggressively incentivize efficiency measures with a disproportionate coincident system peak impact
  - Are we interpreting our tariffs correctly?

Proposed 2007 methodology



We answer to you.

The Post-IRP Business Planning Process

- This is where the DSM results of the IRP are operationalized
- Includes a more detailed assessment of those measures that "passed" the IRP
  - Incorporates consideration of more detailed measure applicability, especially within the non-residential markets
  - Would include additional consideration of residential and non-residential measures that were deemed marginally non-cost-effective in the IRP
- Incorporation into a 2008 DSM Business Plan
  - Establishment of new acquisition goals
    - External goals as well as by portfolio, by Account Executive, by engineer etc.
  - Appropriate budgeting
  - Potential revisions to tariff rider levels
  - Review of infrastructure capabilities
  - Revise target markets and measures
  - Review residential and non-residential prescriptive programs
    - Addition or deletion of measures
    - Revise incentives
  - Establish a plan to pursue measures which may be outside the scope of our current Schedule 90 (DSM) tariff authority

Avista Utilities 2007 Integrated Resource Plan

Technical Advisory Committee Meeting No. 4 Agenda

Wednesday March 28, 2007

	Topic	Time	Staff
1.	Introductions	9:30	Barcus
2.	Review of 3rd TAC Meeting	9:35	Lyons
3.	Market Analysis	9:45	Gall
4.	Load Forecast – Global Warming	11:00	Barcus
5.	Conservation Program Update	11:30	Folsom
6.	Lunch – DSM Presentation	12:00	
7.	Portfolio Selection Criteria	1:00	Gall
8.	Cost of Service	2:00	Knox
9.	Transmission Estimates	2:30	Gnaedinger
10.	Adjourn	3:30	

Review of TAC 3 Meeting

2007 Electric Integrated Resource Plan
Fourth Technical Advisory Committee Meeting
March 28, 2007

John Lyons

TAC Meeting #3 – January 10, 2007

- Draft PRS Review
- Fuel Price Forecast
- Clean Coal Presentation
- Emission Update
- Load Forecast
- Conservation

Comments/Questions from TAC Meeting #3

- What is Plan B if the PRS is not feasible? Why? – Final IRP
- Are we maintaining or increasing our level of risk? – Final IRP
- Chart Net Power Supply Expenses PRS vs. No Additions – Final IRP
- Should a gas hedge be included in the model – net cost or benefit of a hedging premium – Yes
- Adding a premium over market price for avoided cost – Final IRP
- Petroleum coke as a feedstock – Discussion, not modeled
- Correct errors on slides from the last meeting – Done
- Include chart comparing summer vs. winter peak – Final IRP

Market Analyses

2007 Electric Integrated Resource Plan
Fourth Technical Advisory Committee Meeting
March 28, 2007

James Gall

Base Case Market Analysis

- This is the anchor of the IRP analysis
- Mean of 300 potential outcomes
- Assumes average conditions and expectations
- Includes risk measurement
- Some methodology changes since 2005 IRP and 2007 “draft” IRP

Methodology Changes From Prior IRP Analysis

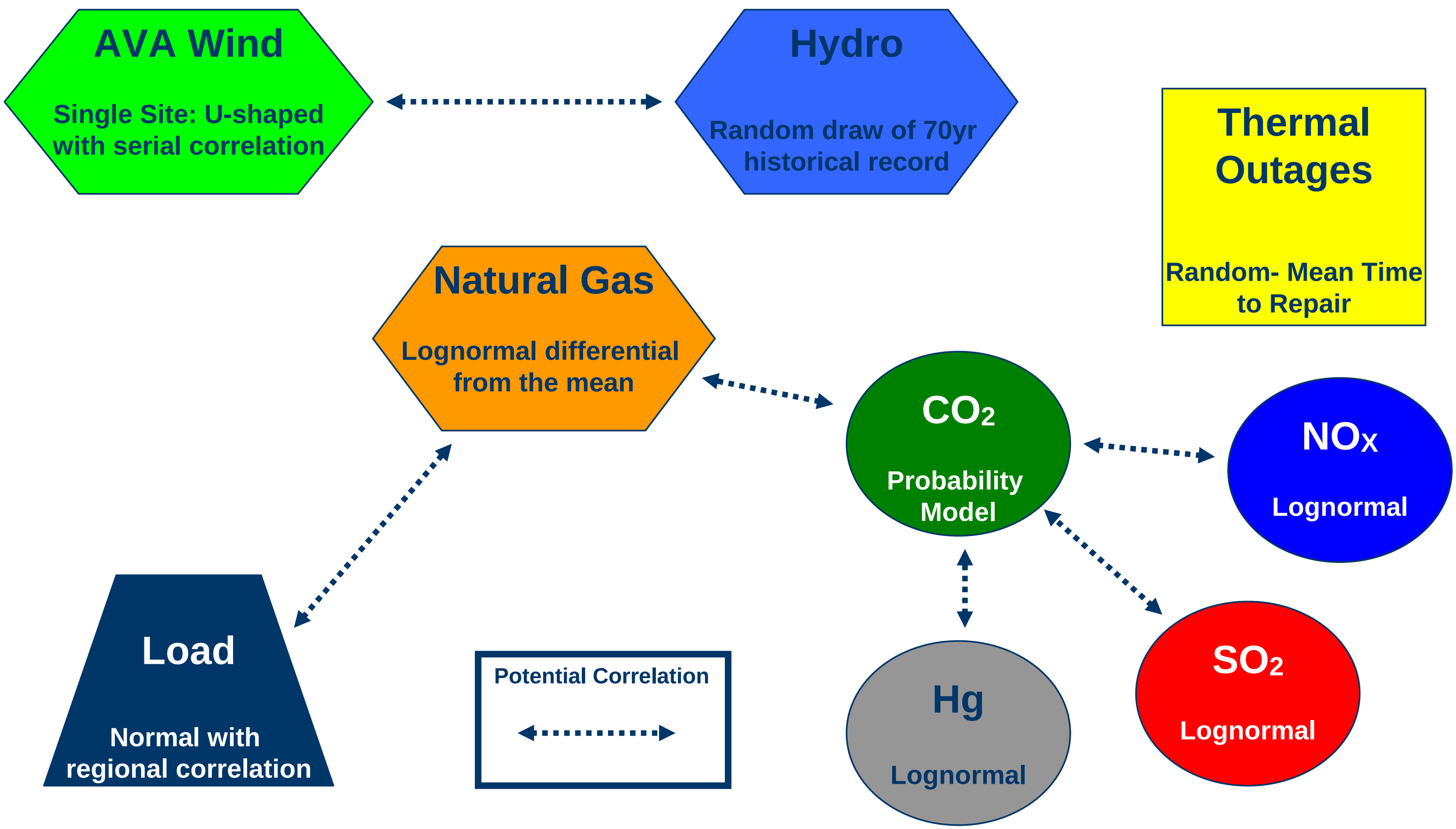
Key Changes

- Regional resource selection must meet planning margin targets
- Uses four Northwest areas rather than one or eight
- Updated fuel prices and capital costs
- Focus on market drivers rather on regional resource speculation
- Added stochastic abilities, methodologies, and iterations
- Carbon “taxes” included in Base Case analysis
- Additional renewables assumed from increased RPS legislation

Stochastic Study Requirements

- Develop deterministic AURORA study using average and expected conditions for the given change
- Develop stochastic (Monte Carlo) models to create data using historical and expected statistics, these are inputted in AURORA
- 300 hourly AURORA simulations between 2008 and 2027 for the entire Western Interconnect
- Requires 2,160 computing hours on 25 CPUs and a large data server that stores 124 GB per study
- Each study takes four days, excluding the time to build the deterministic study

Stochastic Analysis Components



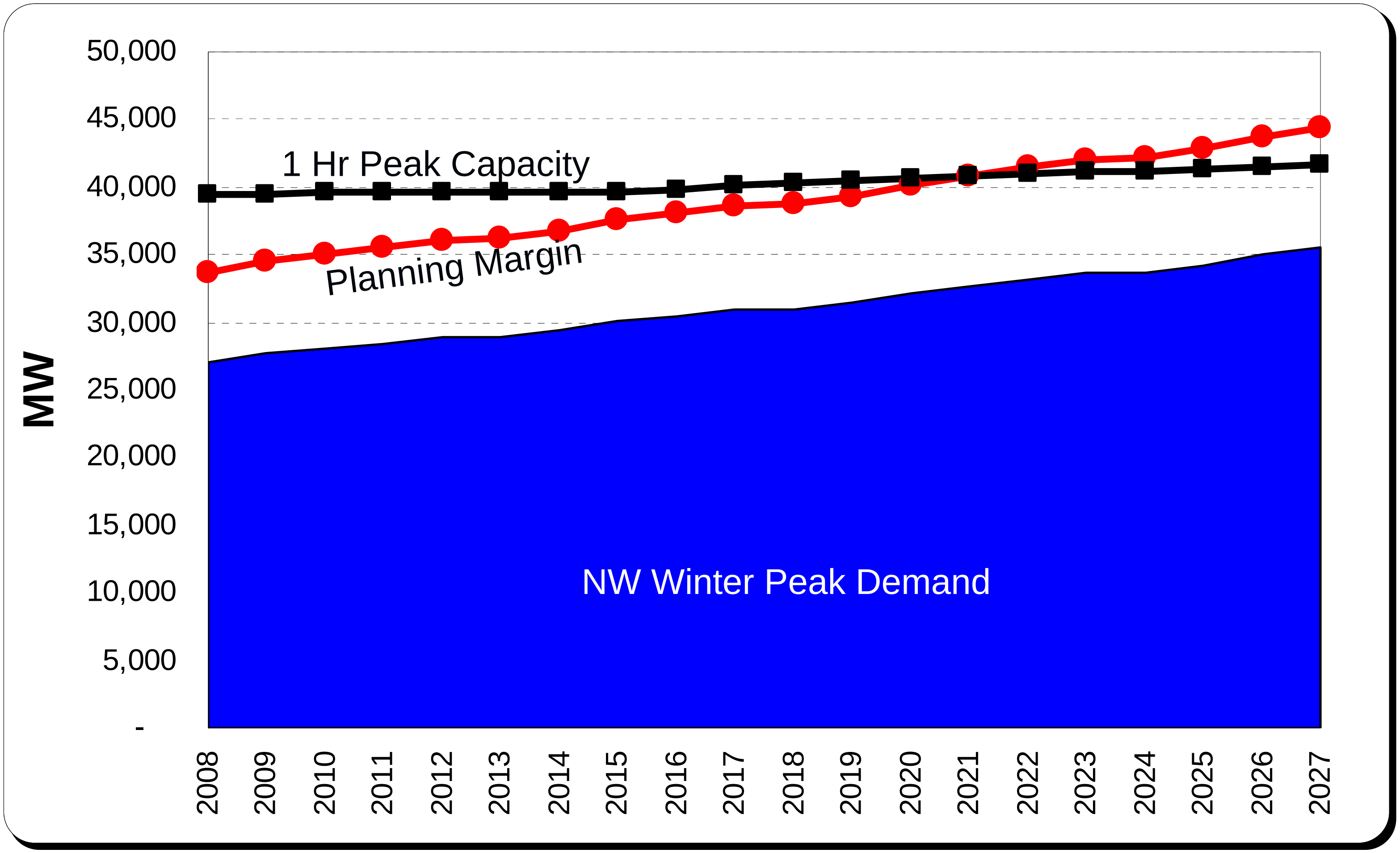
Base Case Key Assumptions

	Entire Study	2008	2017	2027
Natural Gas Price @ Sumas ($/dth)	$5.42 (Real)	$6.54 (Nominal)	$6.44 (Nominal)	$11.18 (Nominal)
Natural Gas Price @ Henry Hub ($/dth)	$6.31 (Real)	$7.62 (Nominal)	$7.50 (Nominal)	$13.02 (Nominal)
Northwest Load (aMW), (WA, OR, N. Idaho)	1.72% (AAGR)	17,584	20,708	24,715
Western Interconnect Load (aMW)	1.95% (AAGR)	100,056	120,056	147,348
Northwest Non-Coincident Peak Demand (MW), (WA, OR, N. Idaho)	1.38% (AAGR)	25,749	29,311	33,863
Western Interconnect Non-Coincident Peak Demand (MW)	2.37% (AAGR)	162,672	202,388	259,667
Hydro Energy (aMW)	14,152	14,067	14,162	14,162
CO_2 Tax ($/Ton)	$4.35 (Real)	$0.00	$9.54 (Nominal)	$14.45 (Nominal)

Base Case: New Resource Selection Western Interconnect *(Cumulative Nameplate MW)*

	2010	2015	2020	2027
CCCT	5,280	15,360	23,040	46,080
SCCT	17,002	31,793	46,661	52,761
Pulverized coal	0	2,800	3,600	5,200
IGCC coal	0	0	2,550	11,900
IGCC coal w/ sequestration	0	0	0	0
Wind (economic)	0	0	0	0
Nuclear	0	0	0	0
RPS wind	2,016	9,499	20,046	29,086
RPS other	638	2,177	4,331	6,457
Total Excluding Wind	*22,920*	*52,130*	*80,182*	*122,398*
Total With Wind @ 33%	*23,585*	*55,265*	*86,797*	*131,966*

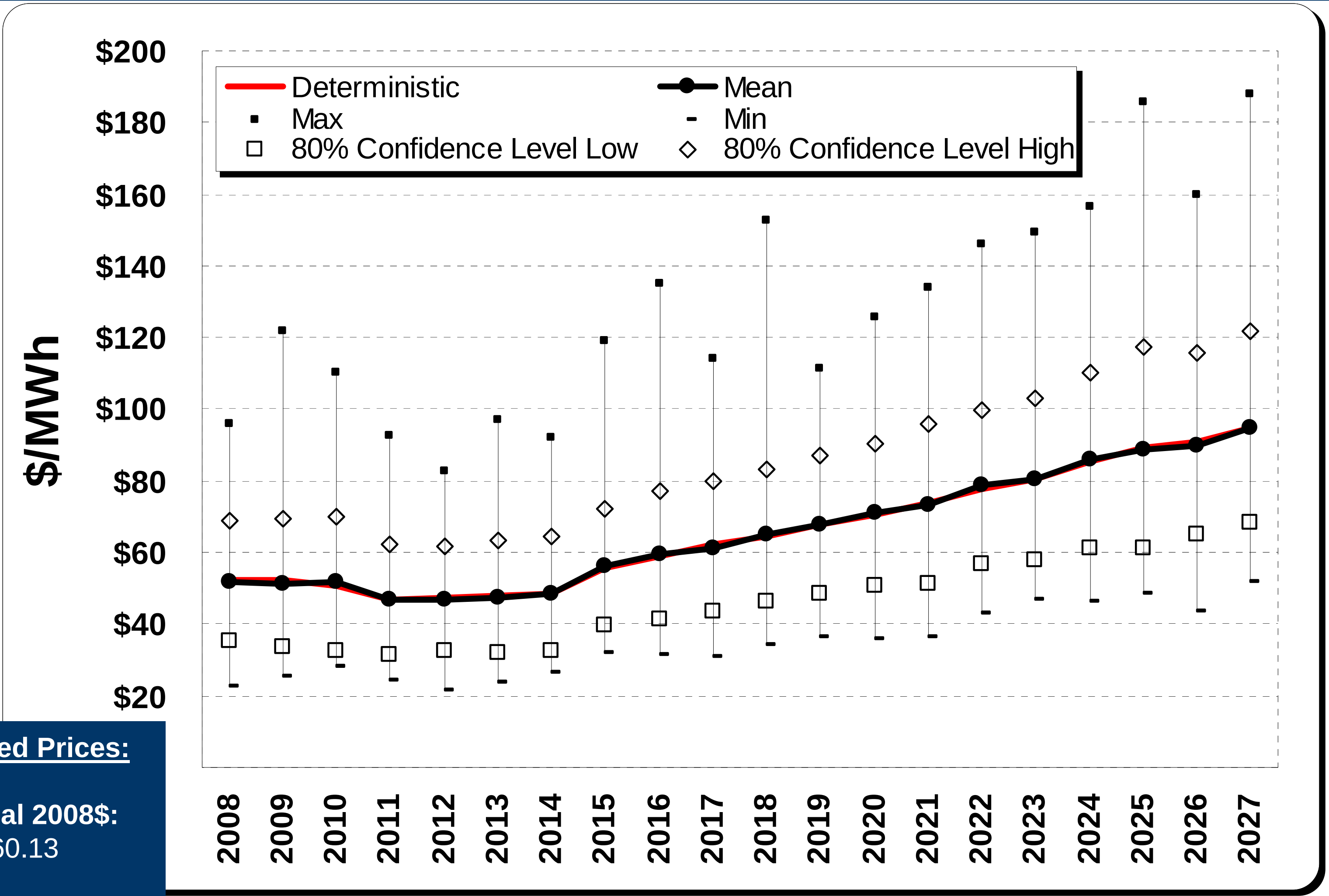
Base Case: Northwest Resource Need
25% Planning Margin, 15% Wind Contribution



Base Case: New Resource Selection in Northwest *(Cumulative Nameplate MW)*

	2010	2015	2020	2027
CCCT	0	0	0	1,920
SCCT	0	0	0	540
Pulverized coal	0	0	0	0
IGCC coal	0	0	0	0
IGCC coal w/ sequestration	0	0	0	0
Wind (economic)	0	0	0	0
Nuclear	0	0	0	0
RPS wind	0	44	2,832	5,835
RPS other	150	261	1,017	1,871
Total Excluding Wind	*150*	*261*	*1,017*	*4,331*
Total With Wind @ 33%	*150*	*276*	*1,952*	*6,257*

Base Case Annual Average Mid-C Prices
Nominal Dollars

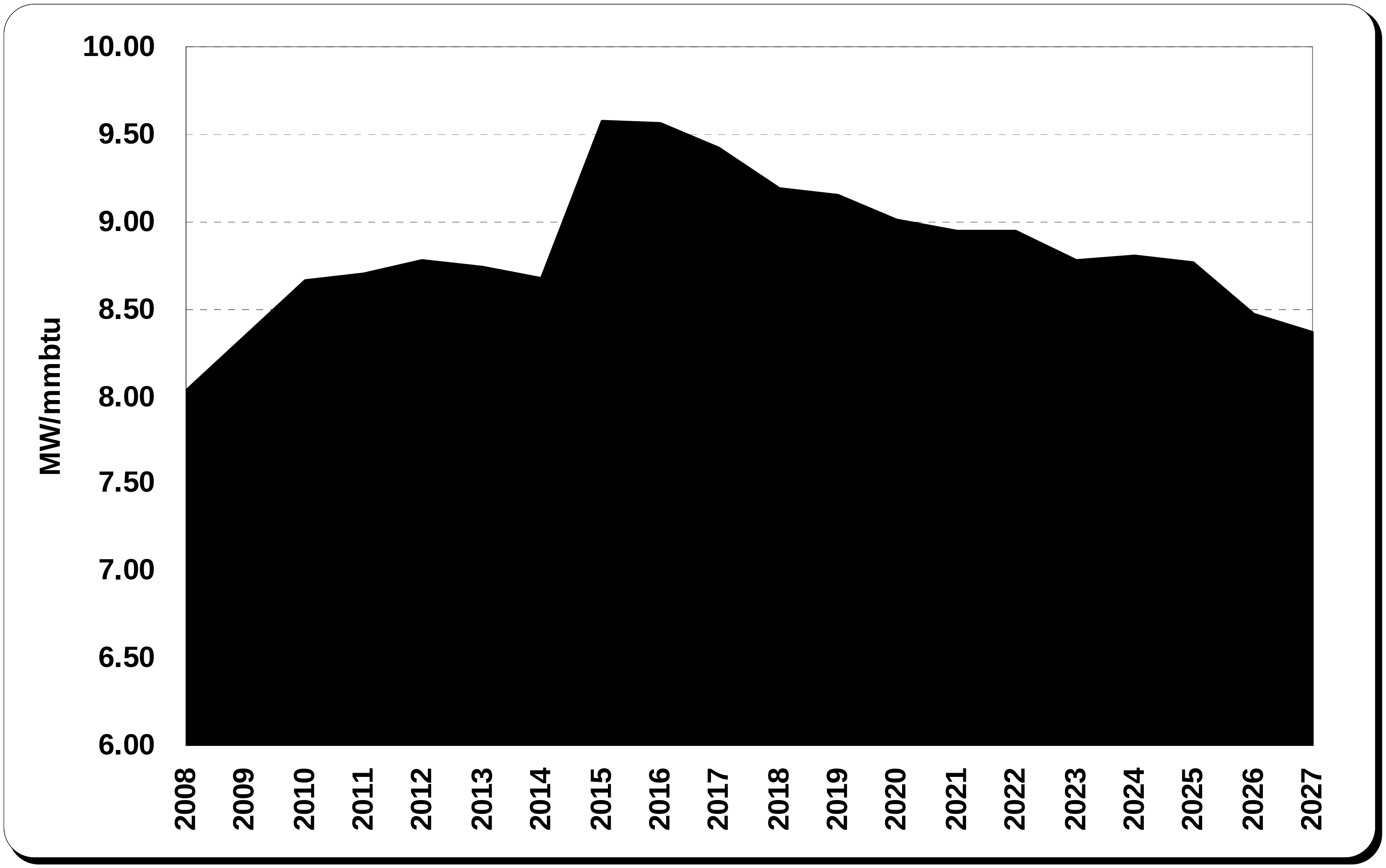


Levelized Prices:

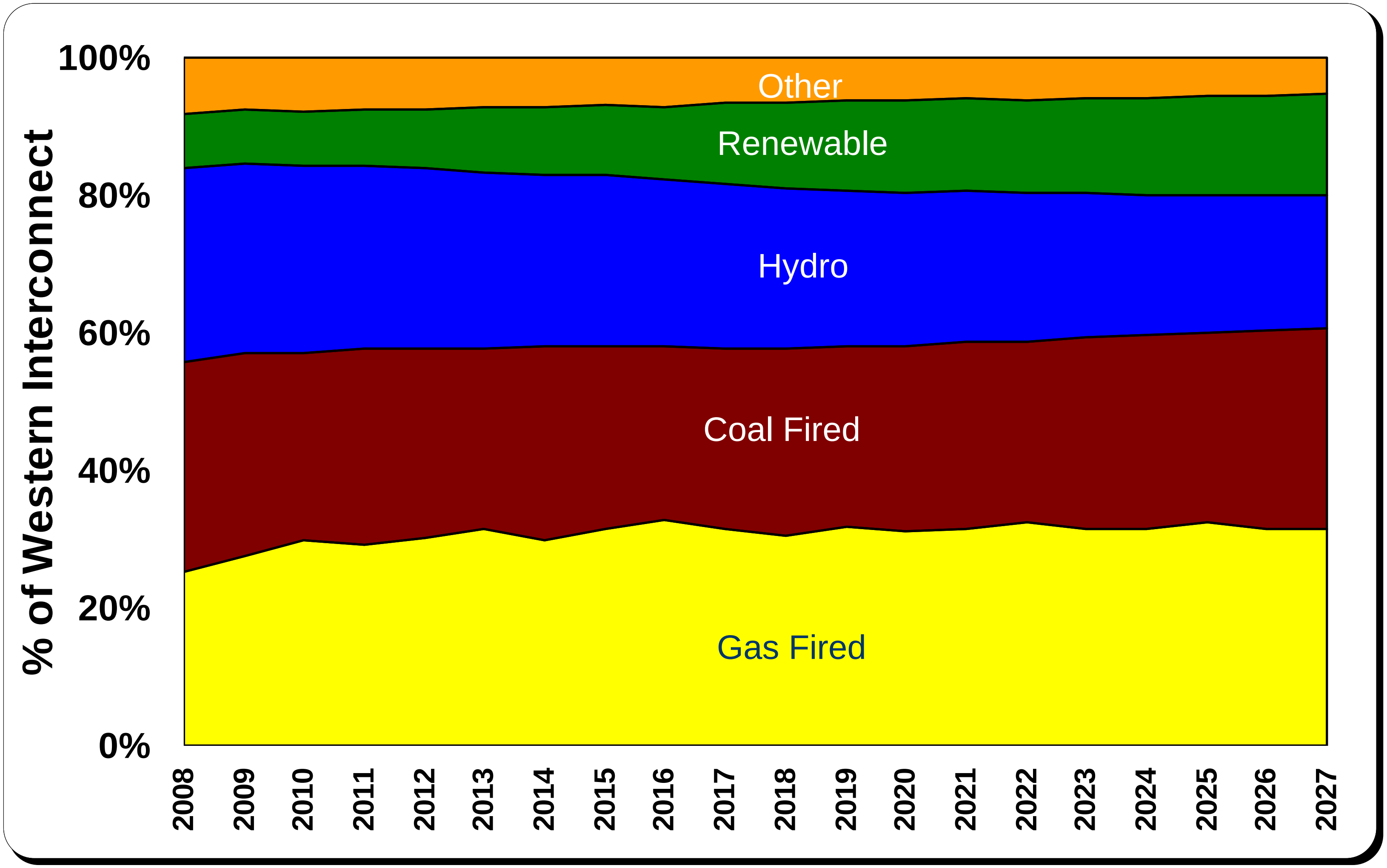
Nominal 2008$:
$60.13

Real 2007$:
$49.59

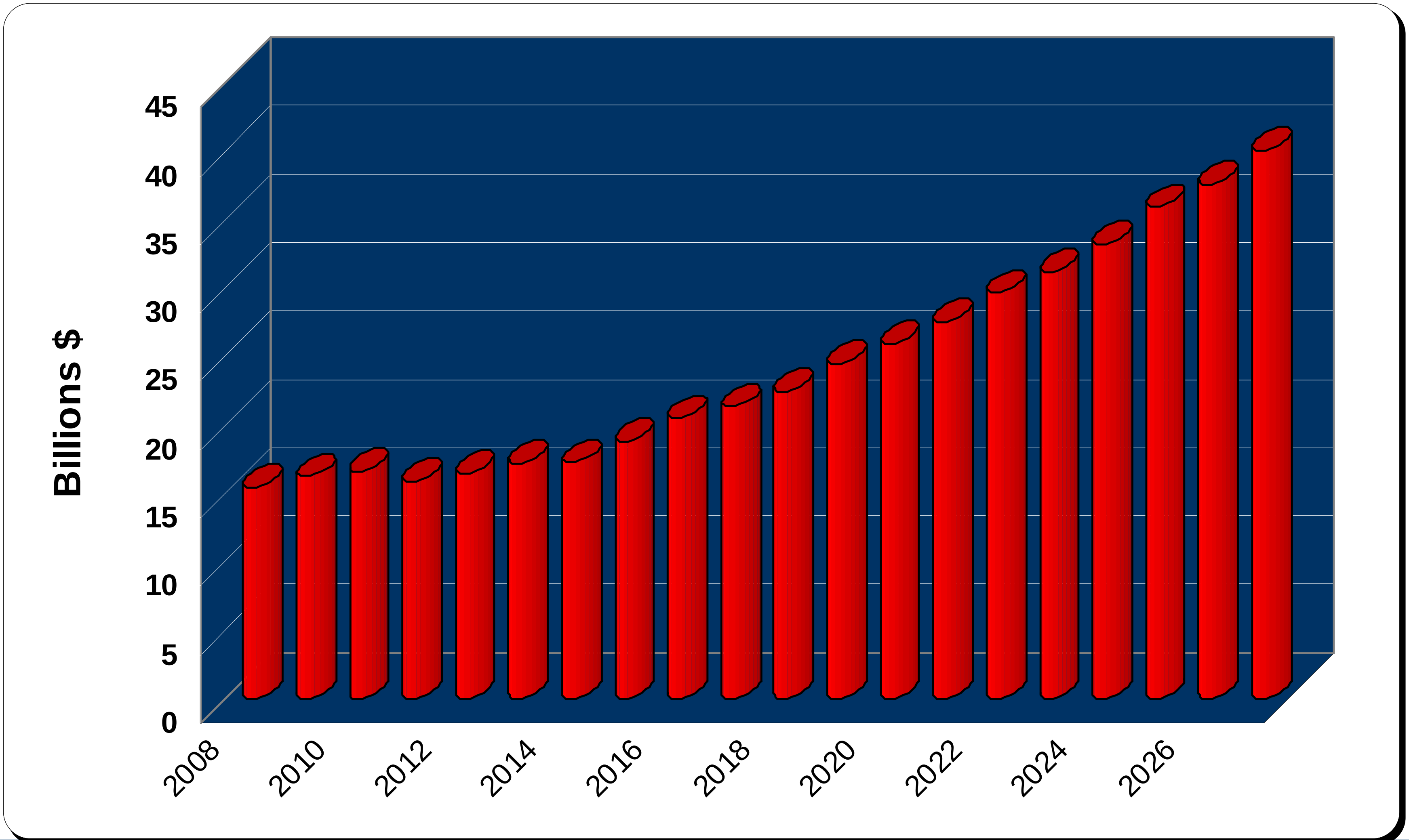
Market Implied Heat Rate- Not Adjusted for CO_2 Tax (Mid-C Electric Price/Sumas NG Price)



Western Interconnect Resource Contribution
(% of Total Energy)



Western Interconnect Total Fuel Costs in Millions Average Annual Growth Rate ~4.9%



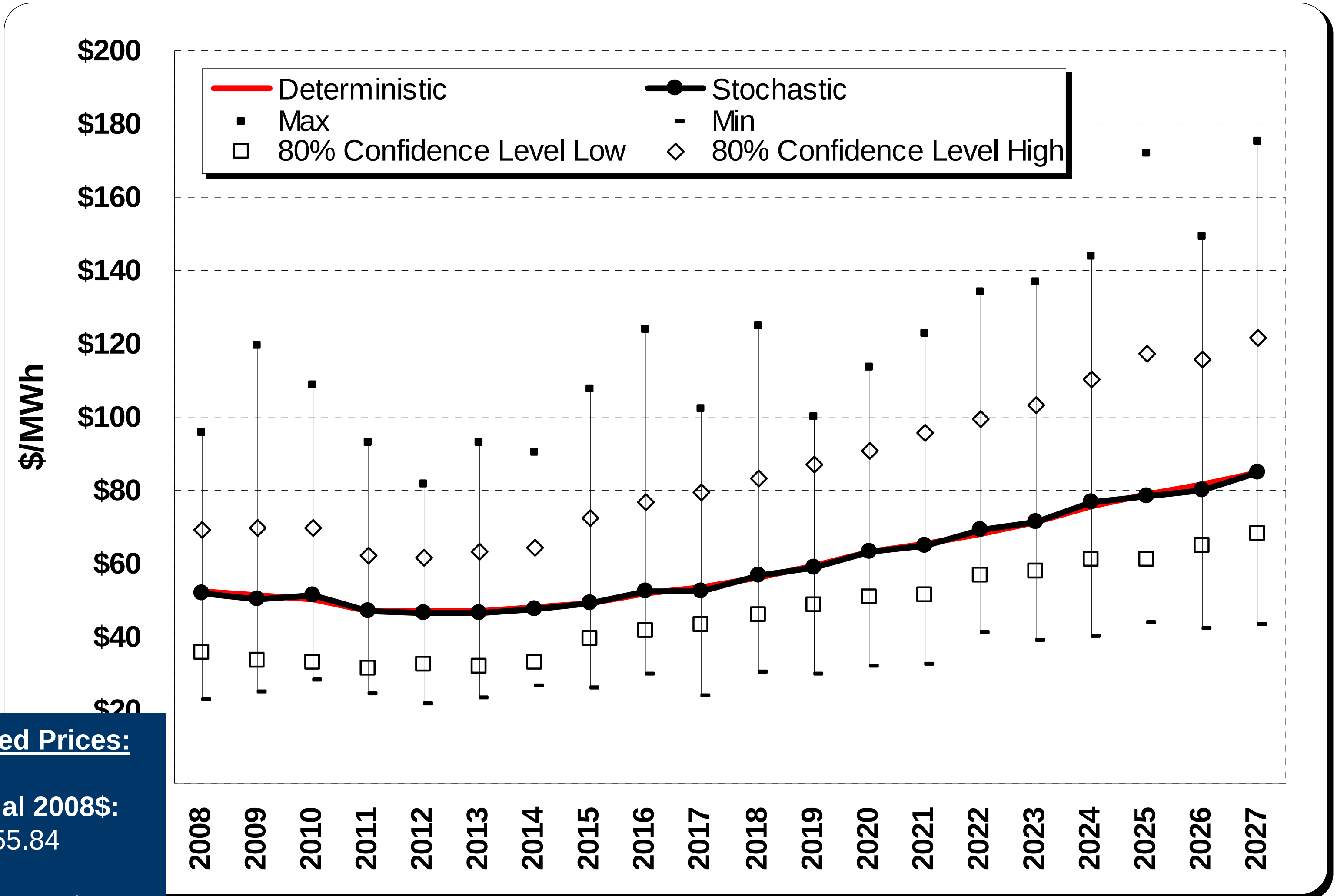
Futures

- These studies are stochastic
- Represent potential macro economic changes
- What are we modeling as futures?
  - No CO_2 taxes
  - Climate Stewardship Act of 2003 (C.S.A.) *[modified]*
  - More volatile natural gas markets
  - No relaxation in gas markets *(still in process, deterministic presented)*

No CO_2 Taxes: New Resource Selection Western Interconnect *(Cumulative Nameplate)*

	2010	2015	2020	2027
CCCT	2,400	15,360	23,040	48,000
SCCT	19,860	31,693	45,299	49,031
Pulverized coal	0	3,600	4,400	6,800
IGCC coal	0	425	6,375	11,900
IGCC coal w/ sequestration	0	0	0	0
Wind (economic)	0	0	0	0
Nuclear	0	0	0	0
RPS wind	2,016	9,499	20,046	29,086
RPS other	638	2,177	4,331	6,457
Total Excluding Wind	22,898	53,255	83,445	122,188
Total With Wind @ 33%	23,563	56,390	90,060	131,786

No CO_2 Tax: Annual Average Mid-C Prices
Nominal Dollars



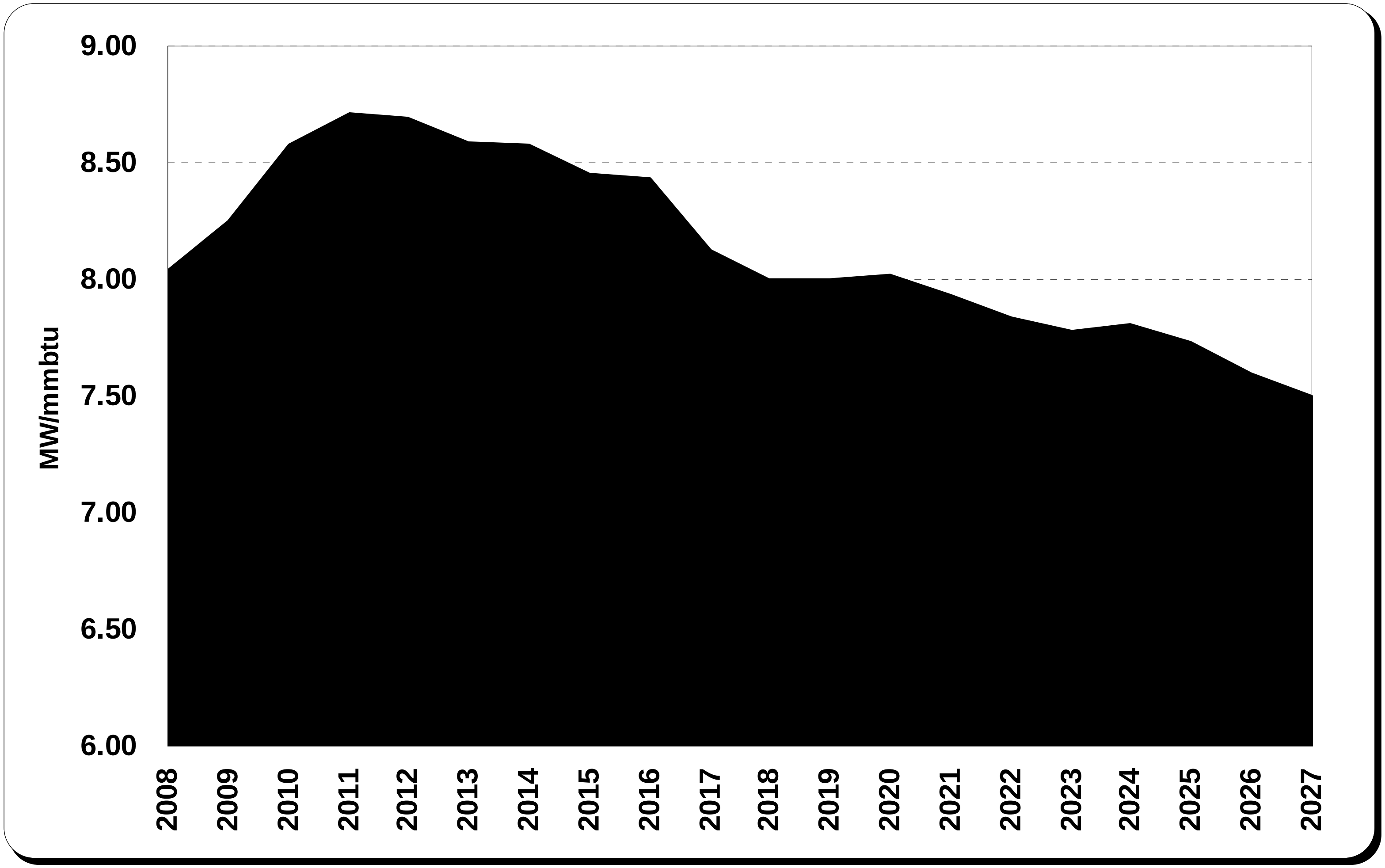
Levelized Prices:

Nominal 2008$:
$55.84

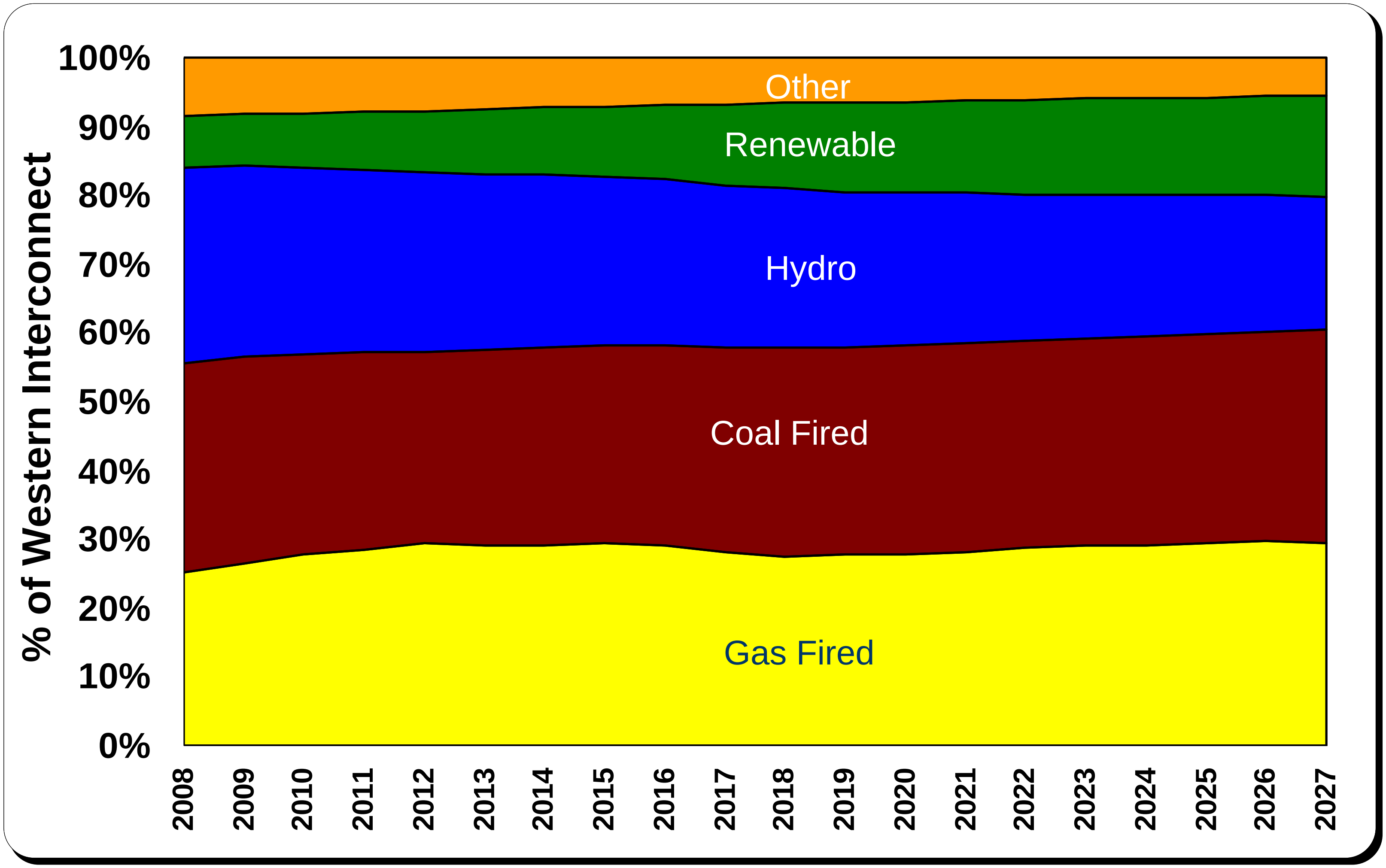
Real 2007$:
$46.05

No CO_2 Tax: Market Implied Heat Rate

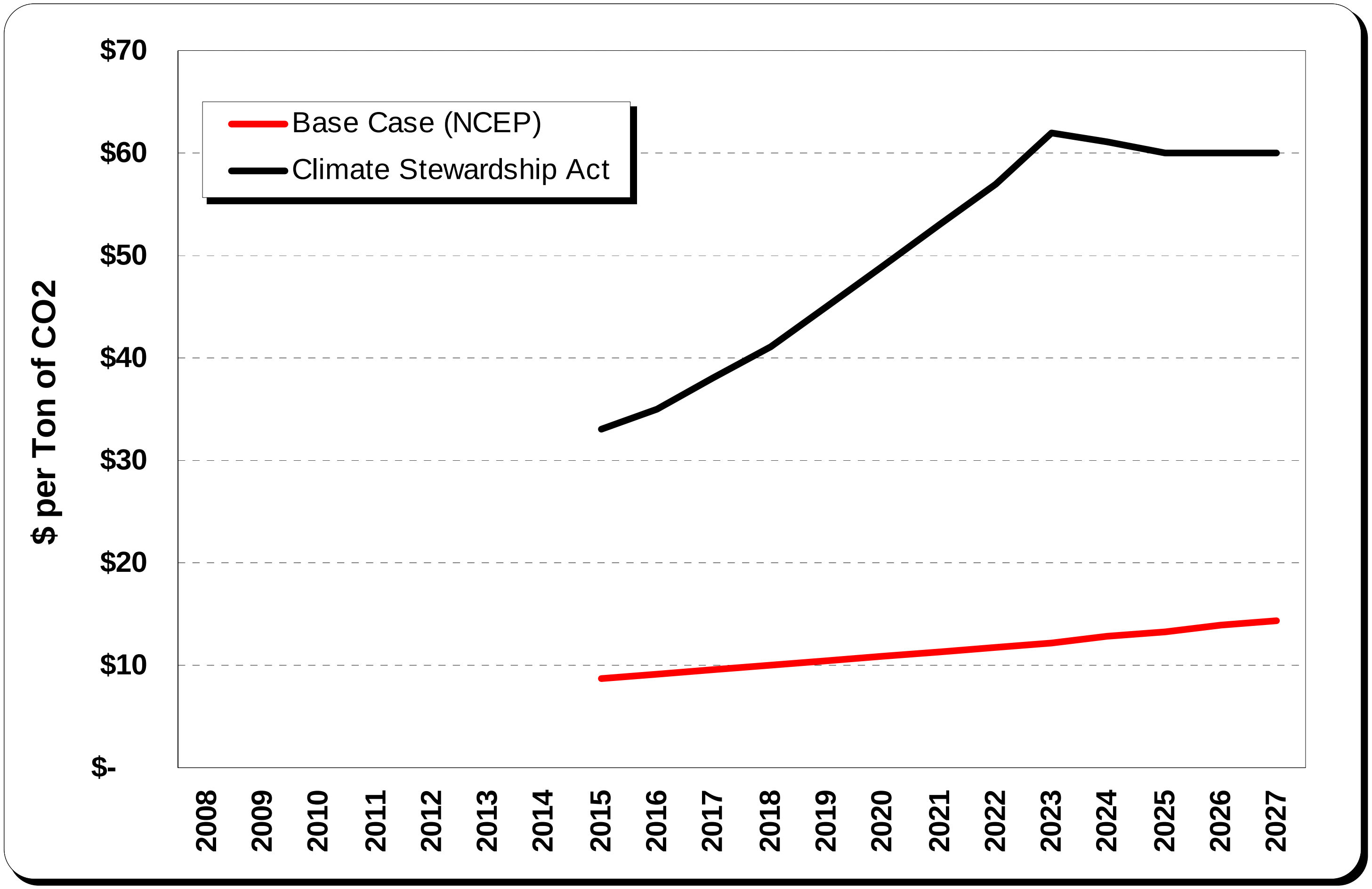
(Mid-C Electric Price/Sumas NG Price)



No CO_2 Tax: Western Interconnect Resource Contribution *(% of Total Energy)*



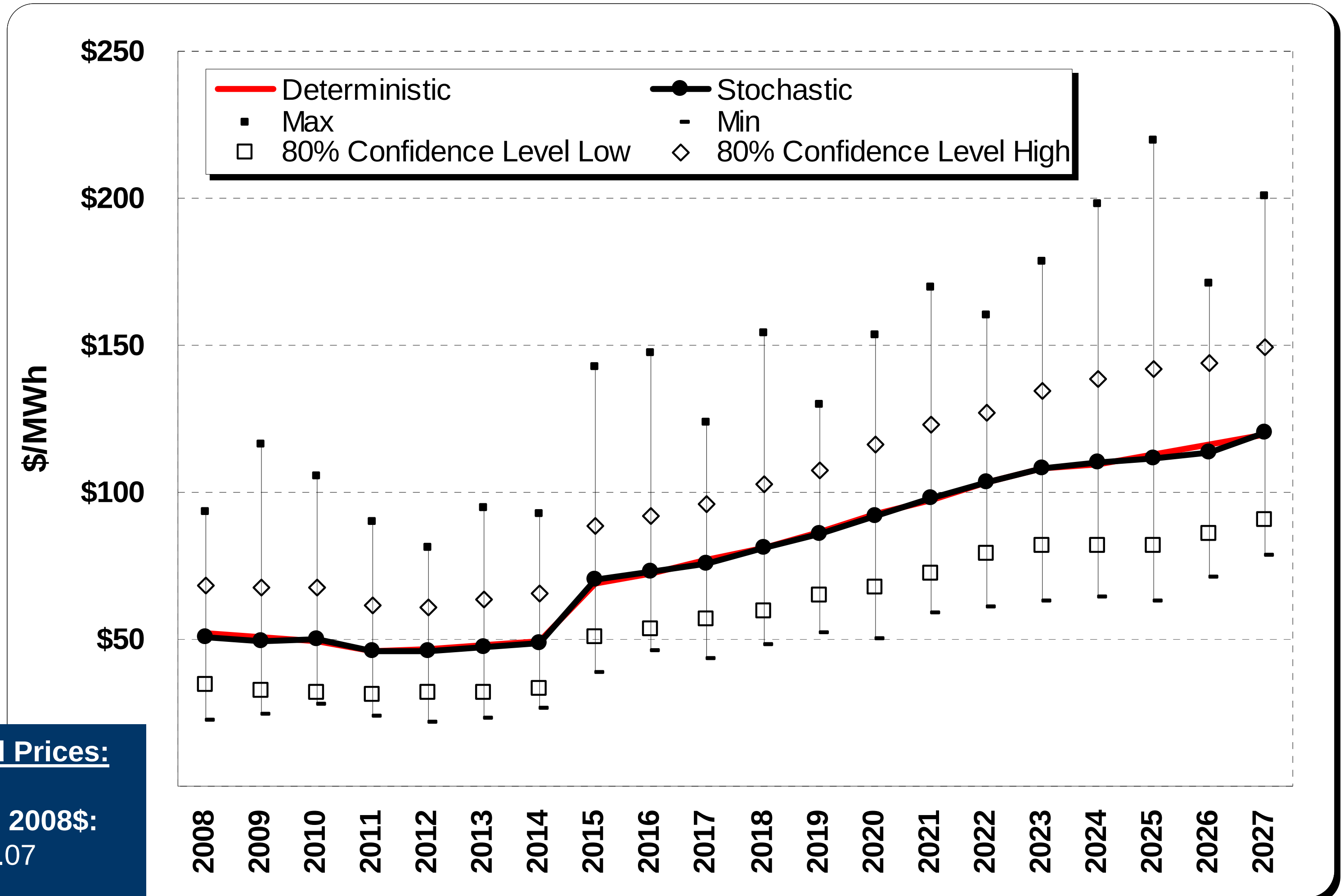
Carbon Tax Assumptions for High Carbon Tax Future (Climate Stewardship Act of 2003)



C.S.A. CO_2 Taxes: New Resource Selection Western Interconnect *(Cumulative Nameplate MW)*

	2010	2015	2020	2027
CCCT	6,240	12,000	23,520	46,560
SCCT	15,176	33,206	44,010	50,573
Pulverized coal	0	1,200	1,200	1,600
IGCC coal	0	0	0	2,975
IGCC coal w/ sequestration	0	0	1,203	5,213
Wind (economic)	0	0	0	0
Nuclear	0	0	0	0
RPS wind	2,016	9,499	20,046	29,086
RPS other	638	2,177	4,331	6,457
Total Excluding Wind	22,054	48,583	74,264	113,378
Total With Wind @ 33%	22,719	51,718	80,879	122,976

C.S.A. CO_2 Taxes: Annual Average Mid-C Prices *Nominal Dollars*



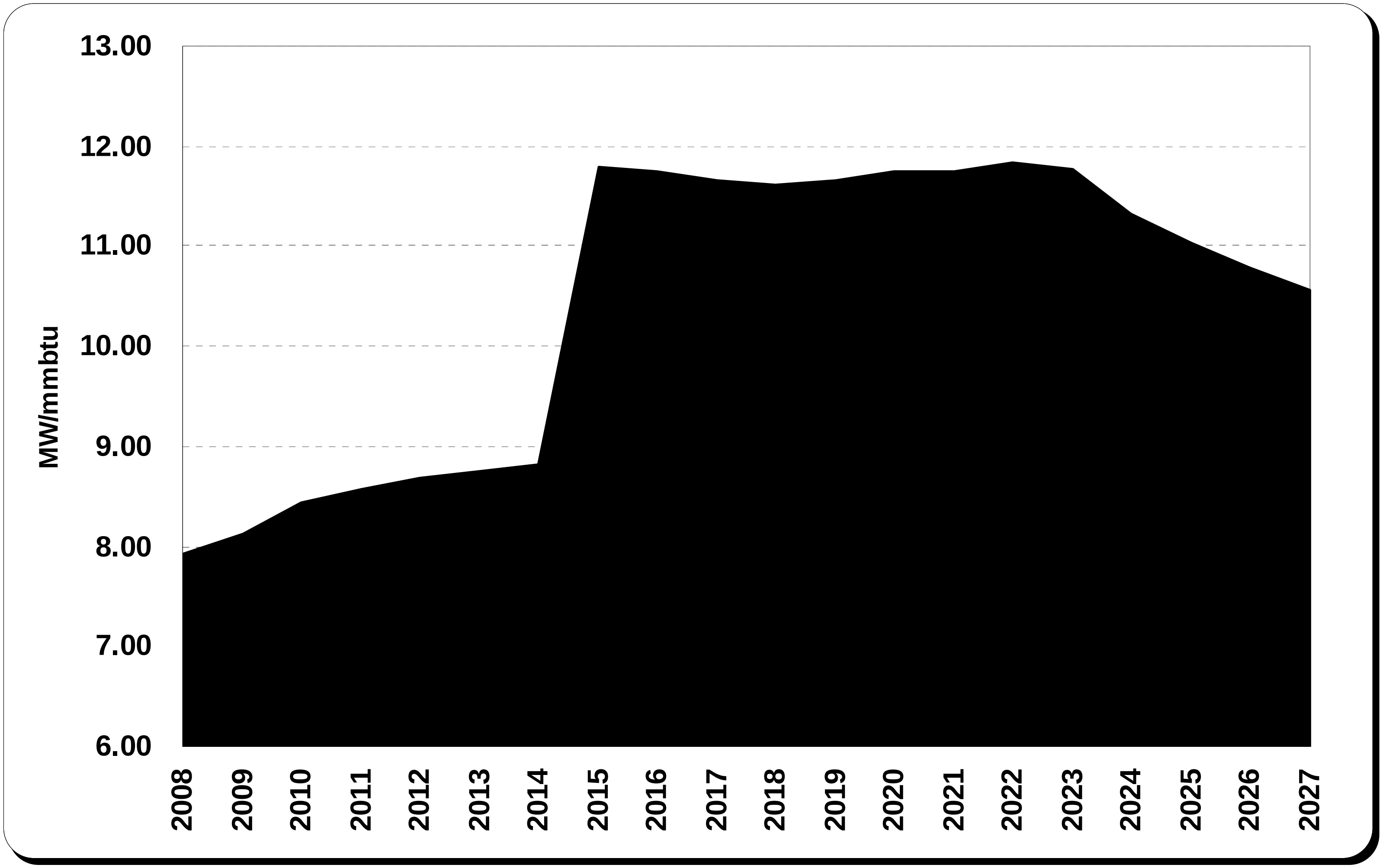
Levelized Prices:

Nominal 2008$:
$69.07

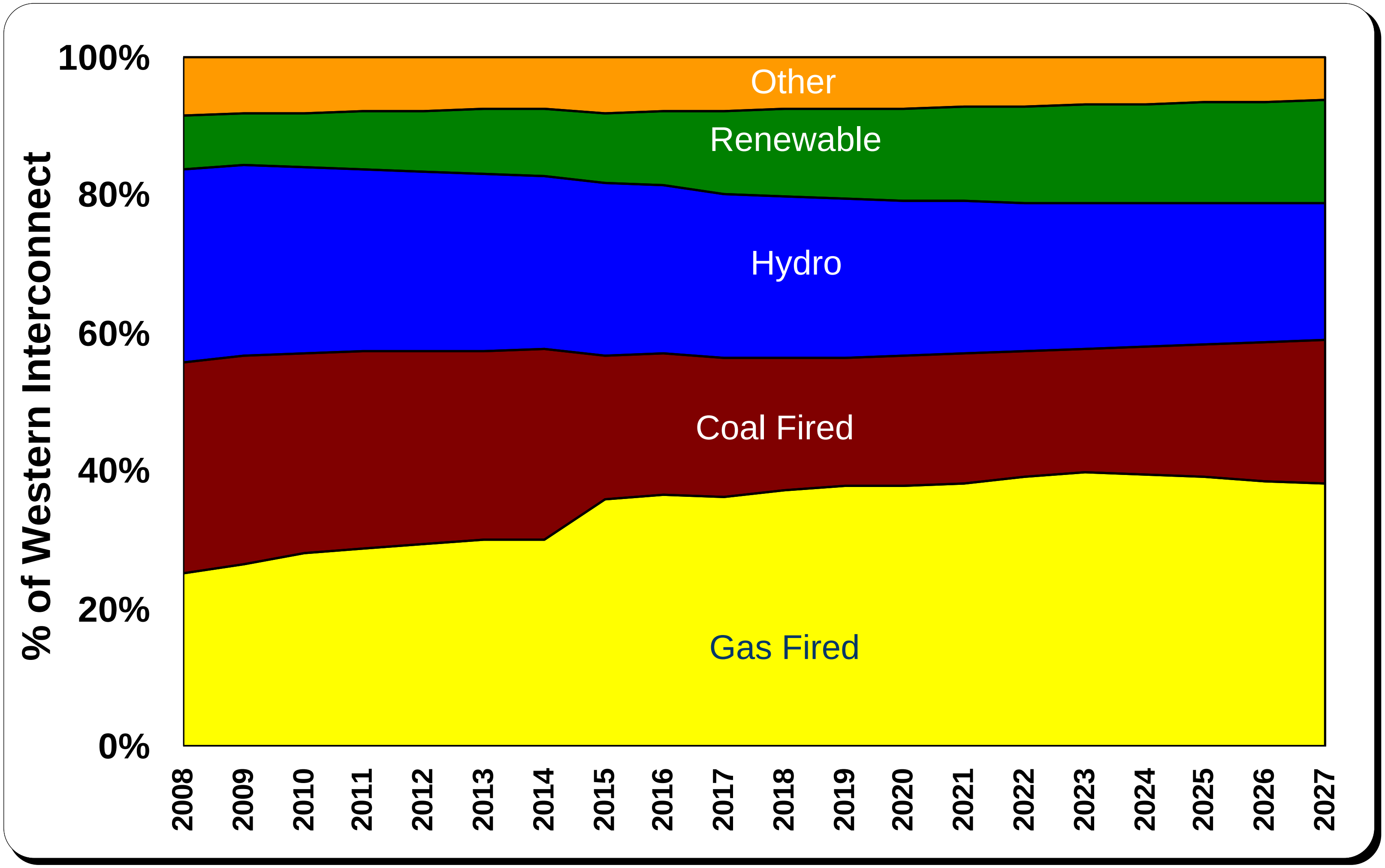
Real 2007$:
$56.96

C.S.A. CO_2 Taxes: Market Implied Heat Rate

(Mid-C Electric Price/Sumas NG Price)

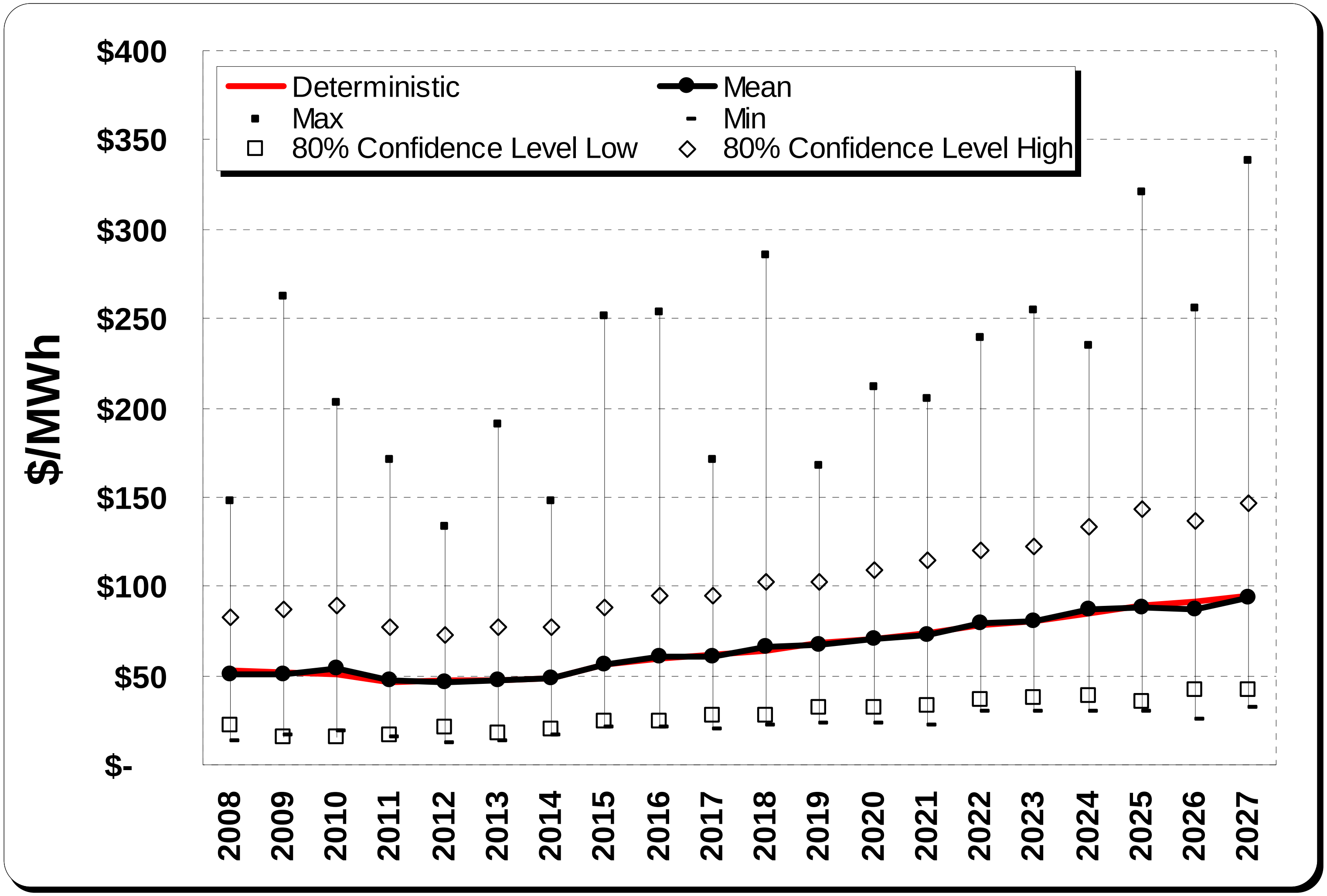


C.S.A. CO_2 Taxes: Western Interconnect Resource Contribution *(% of Total Energy)*

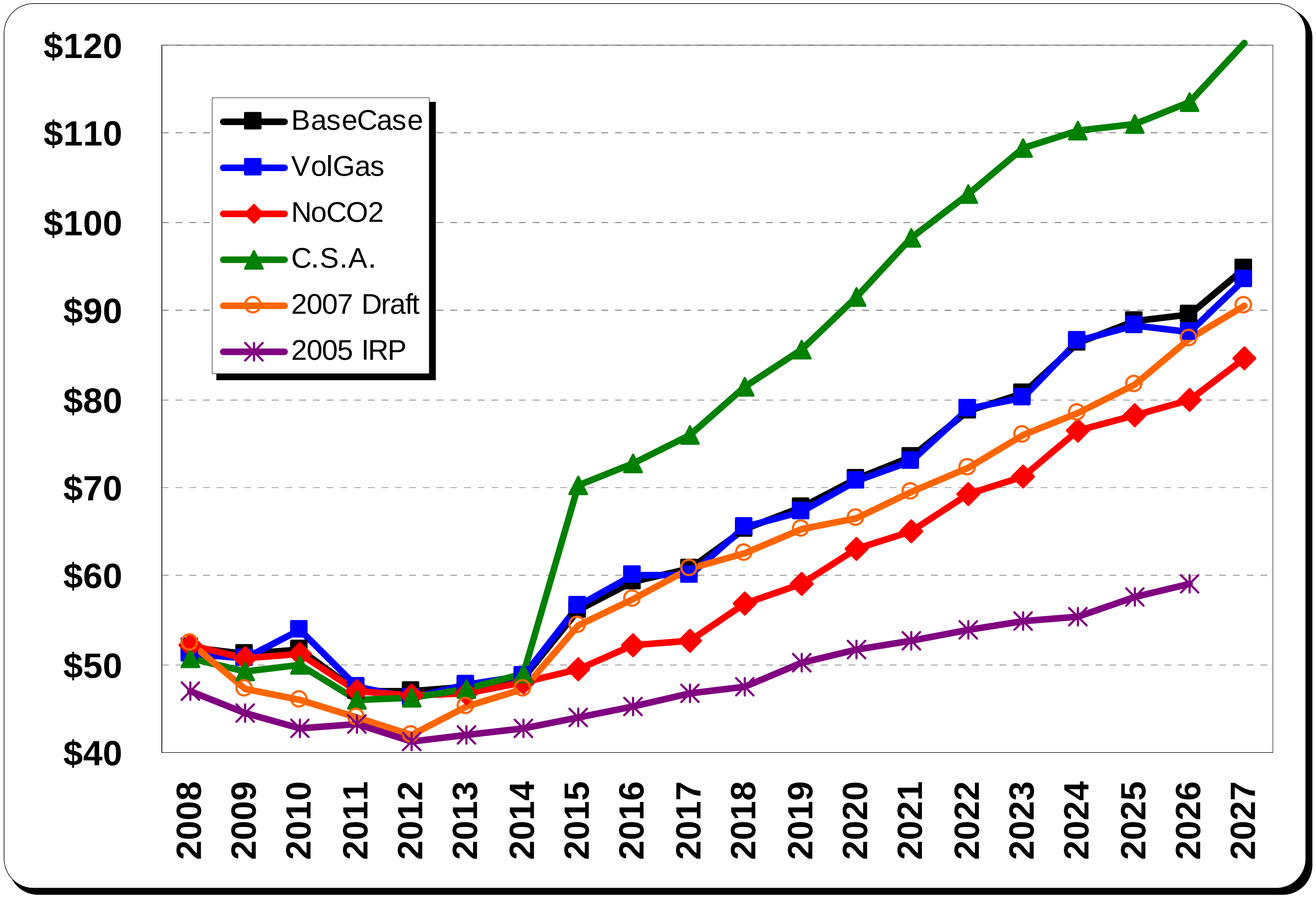


Volatile Gas: Annual Average Mid-C Prices

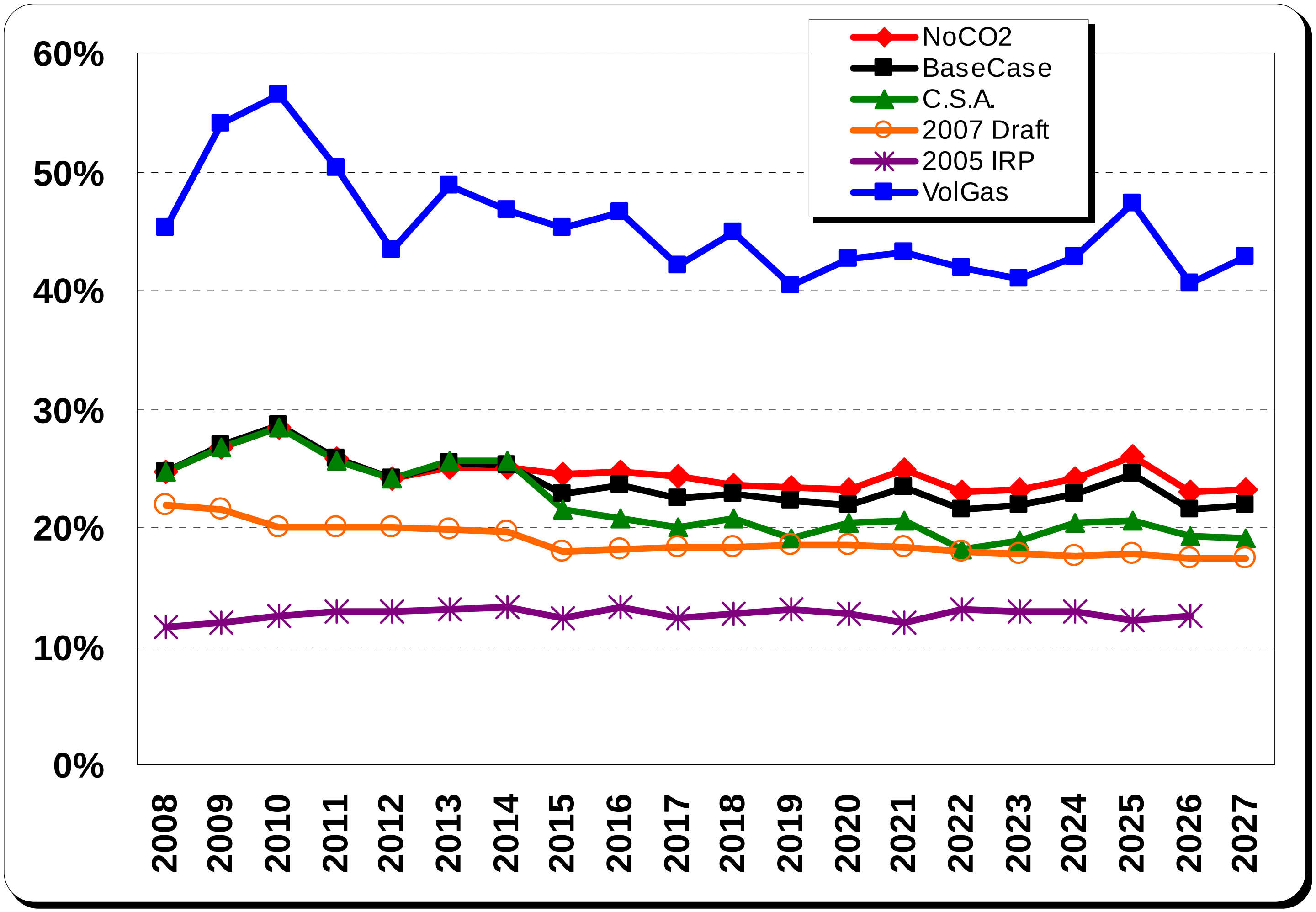
Nominal Dollars



Mid-C Electric Forecast Comparison



Mid-C Electric Forecast Comparison of Volatility *(Mid-C Annual Avg/ Mid-C Annual Stdev)*



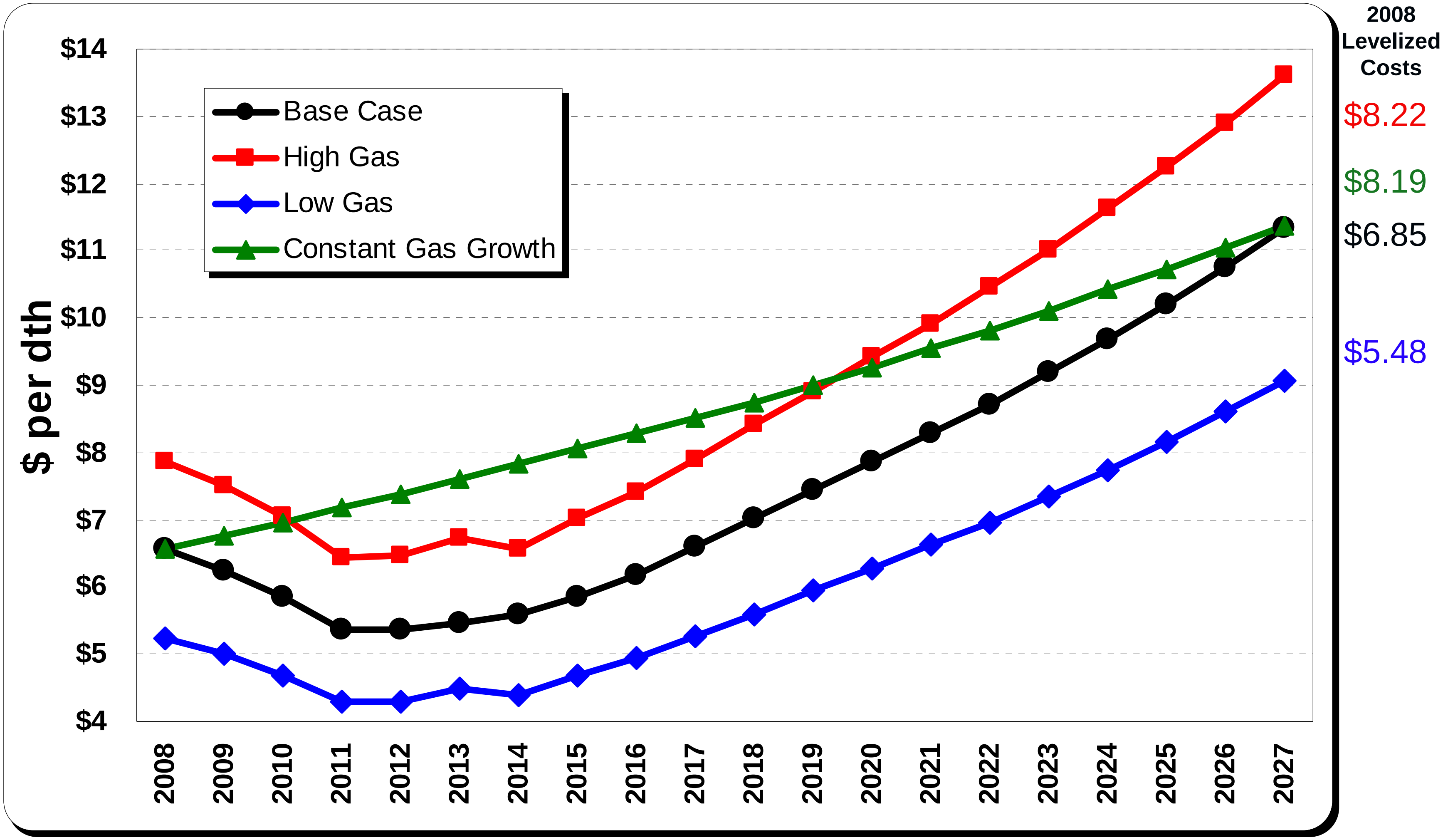
Market Scenarios

- These studies are deterministic
- Represent specific macro changes
- What are we modeling has scenarios?
  - 20% higher & lower natural gas prices
  - 50% higher & lower regional load growth
  - Nuclear available in 2015
  - High electric car penetration
  - No new coal resources
  - Global Warming (hydro and load changes)
  - No new natural gas plants after 2015

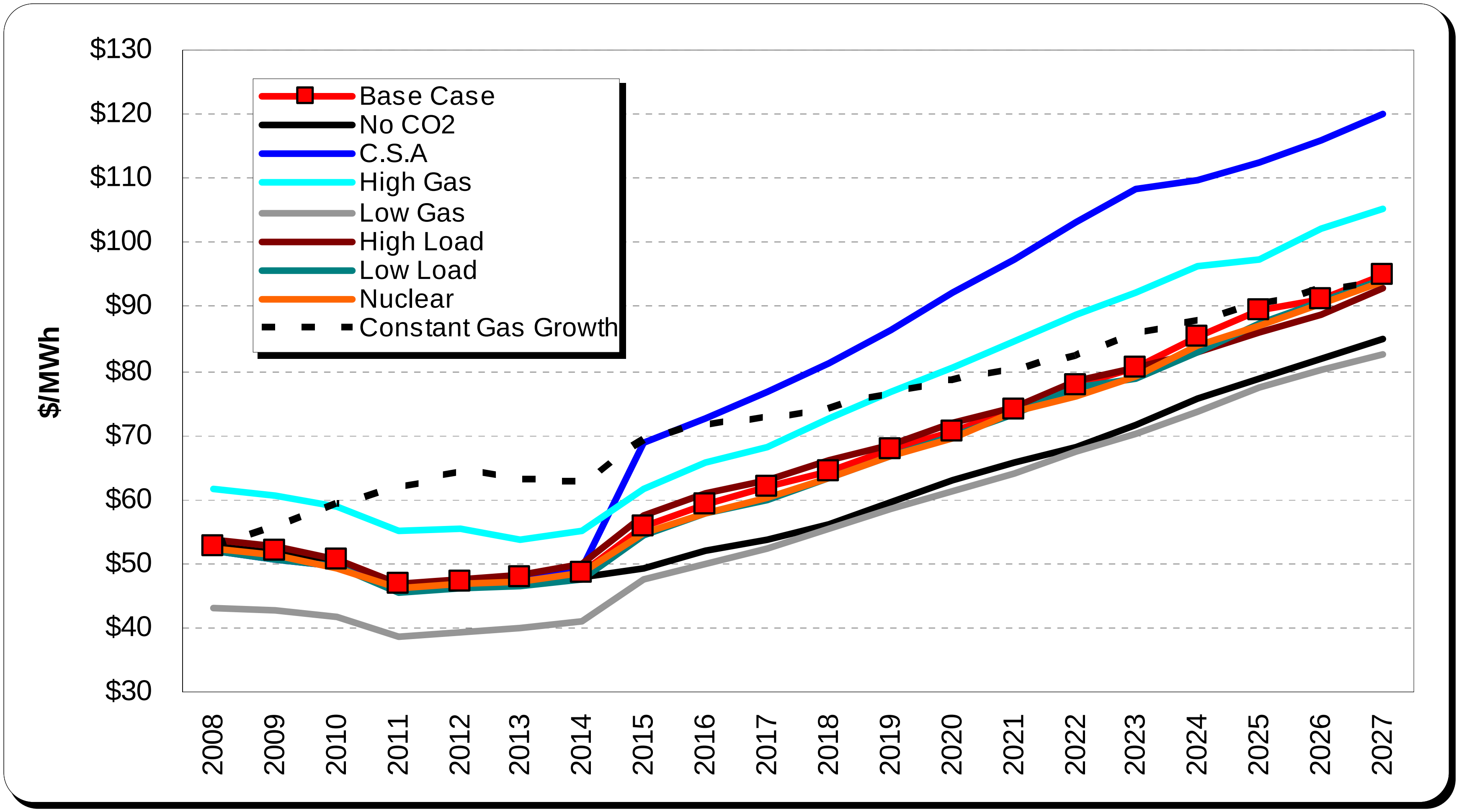
Not Completed Yet!

Others?

Gas Price Scenarios



Scenarios Electric Price Forecasts… So Far

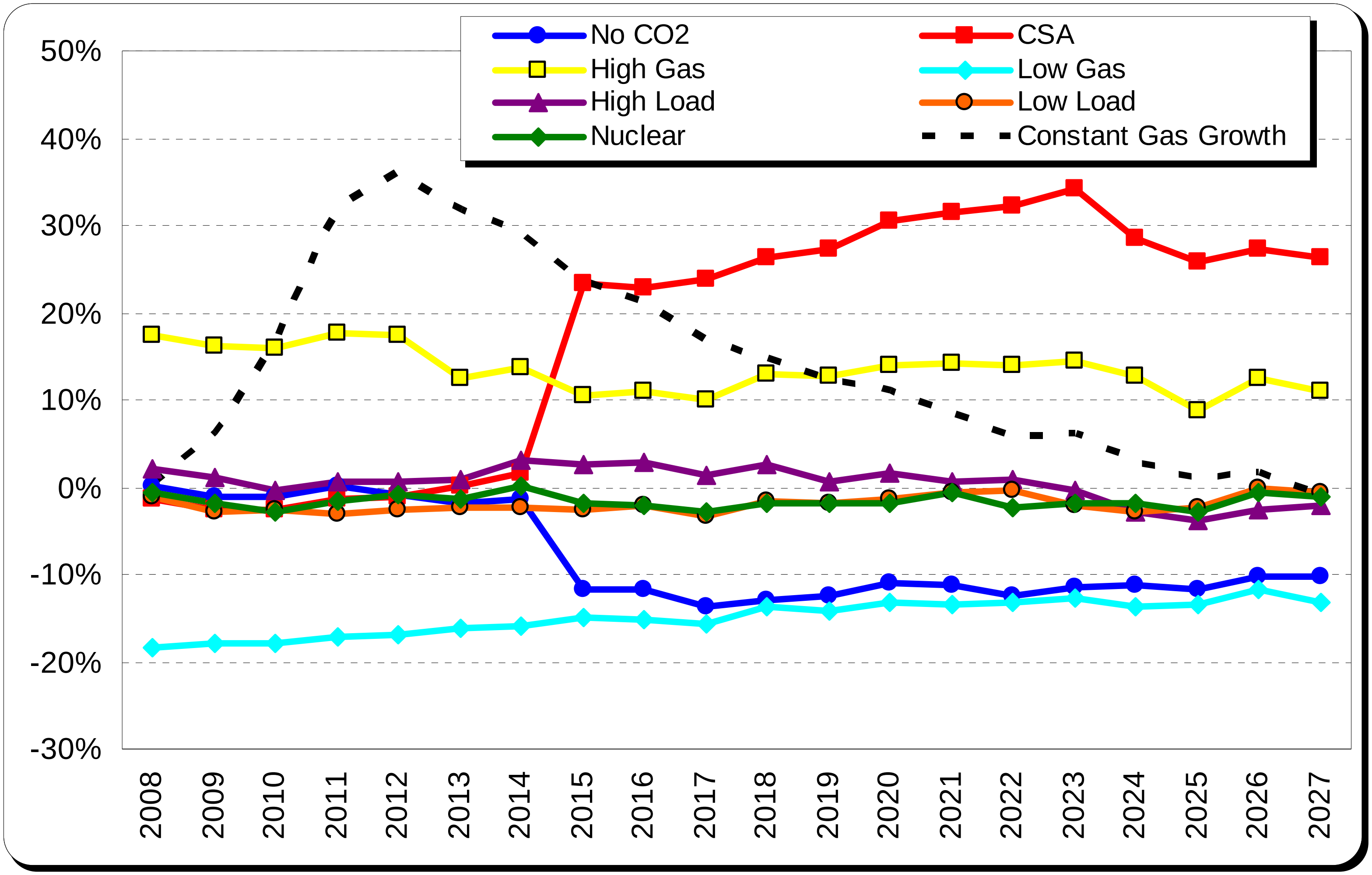


Mid-C Electric Comparison (Nominal $/MWh)

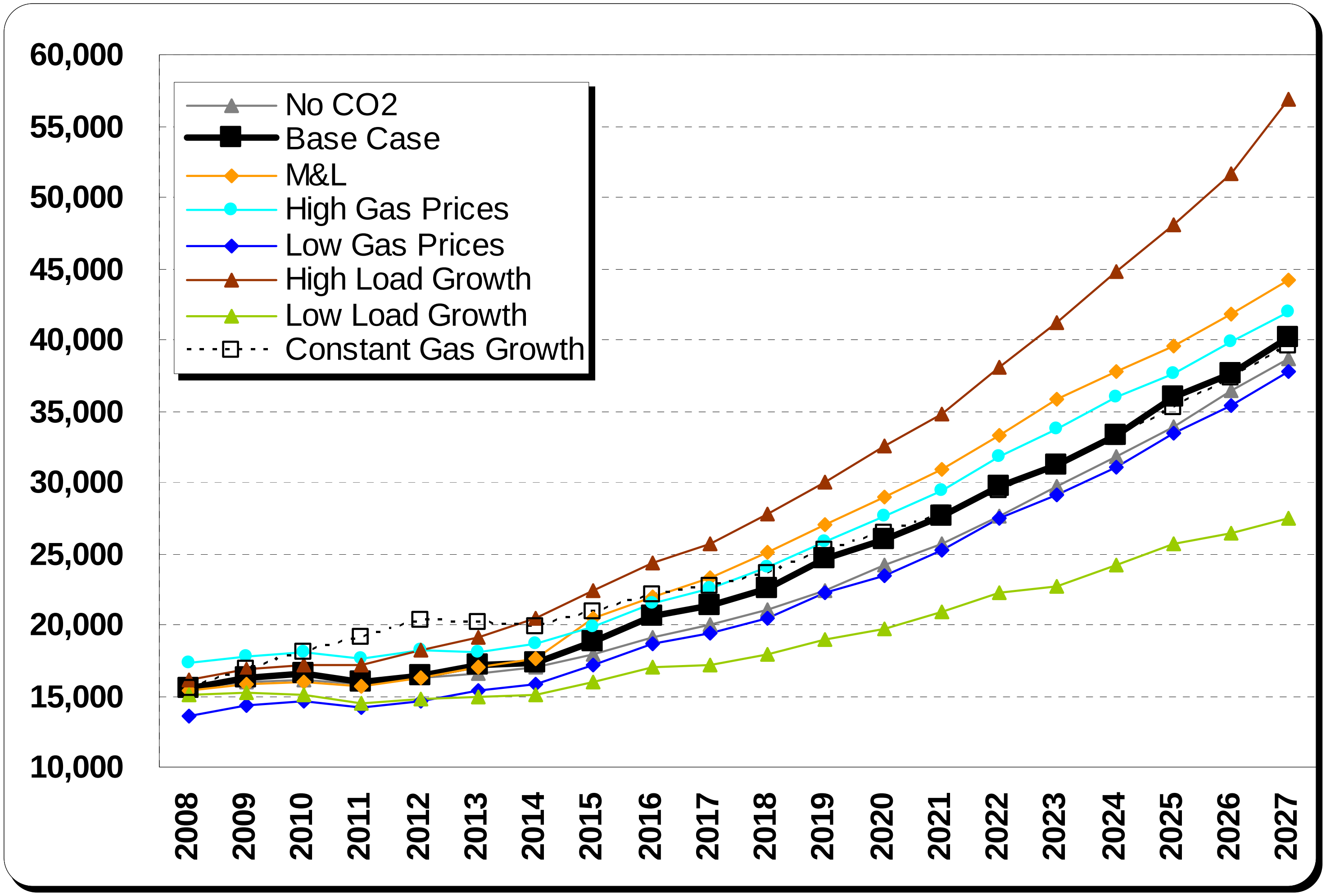
Study	Levelized Cost 2007 $ Real	Levelized Cost 2008 Nominal	2008	2010	2015	2020	2027
Base Case/Volatile Gas	49.59	60.13	52.58	50.79	55.91	70.69	94.86
No CO_2	46.05	55.84	52.65	50.27	49.35	62.98	85.11
C.S.A.	56.96	69.96	51.92	49.42	68.90	92.29	119.89
Constant Gas Growth	58.46	68.82	52.76	59.18	69.12	78.45	94.07
High Gas (20%)	58.32	68.59	61.77	58.93	61.76	80.57	105.35
Low Gas (-20%)	43.43	51.03	42.92	41.68	47.62	61.44	82.43
High Regional Load Growth	51.57	60.65	53.72	50.63	57.37	71.76	92.84
Low Regional Load Growth	50.22	59.05	51.94	49.45	54.47	69.76	94.39
Nuclear available 2015	50.43	59.29	52.27	49.38	54.89	69.42	93.87

Significant Difference from Base Case

All Market Studies Mid-C Price % Change from Base Case



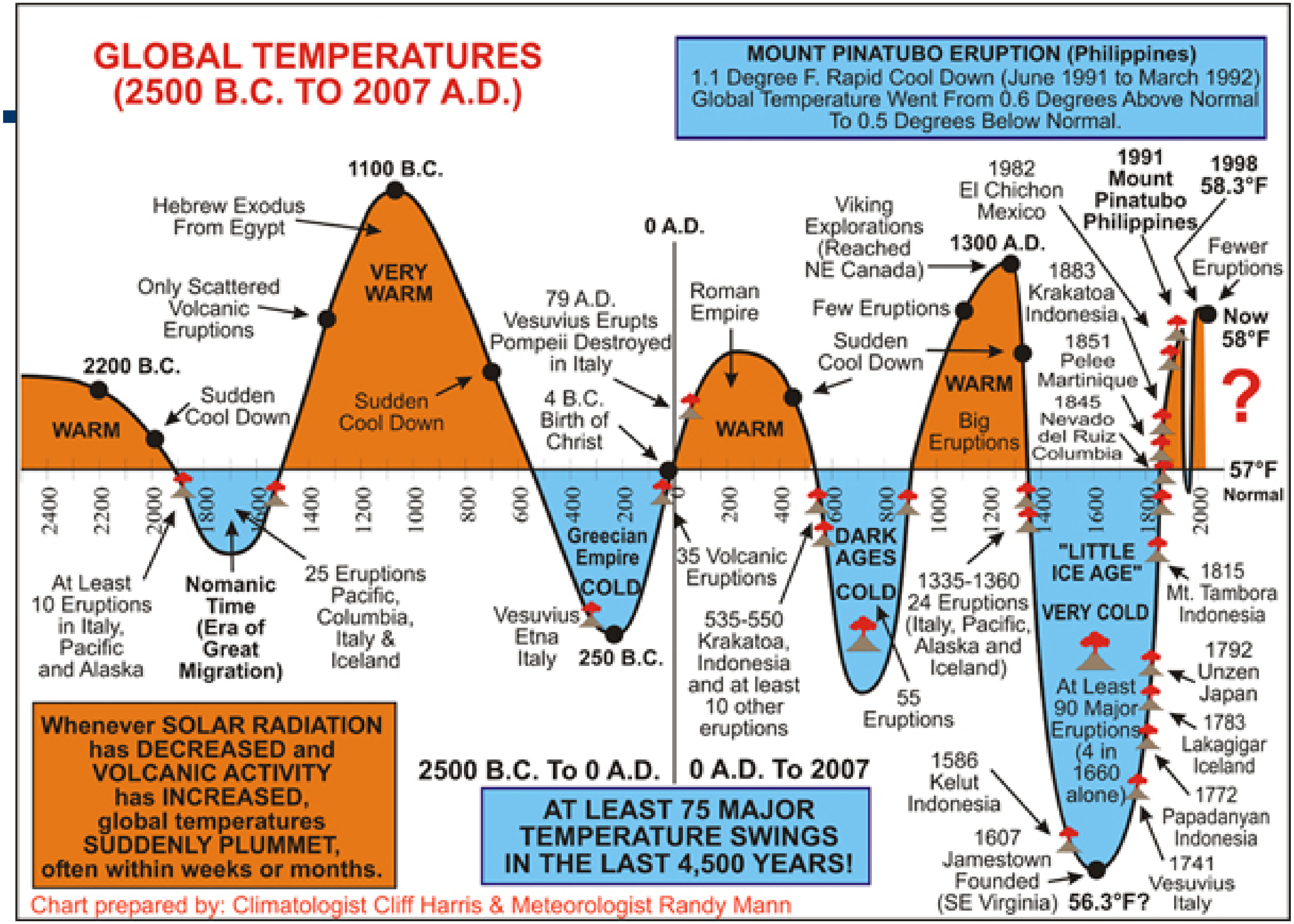
All Market Studies Total Fuel Costs (Nominal)



Global Warming Degree Day Trend Scenario

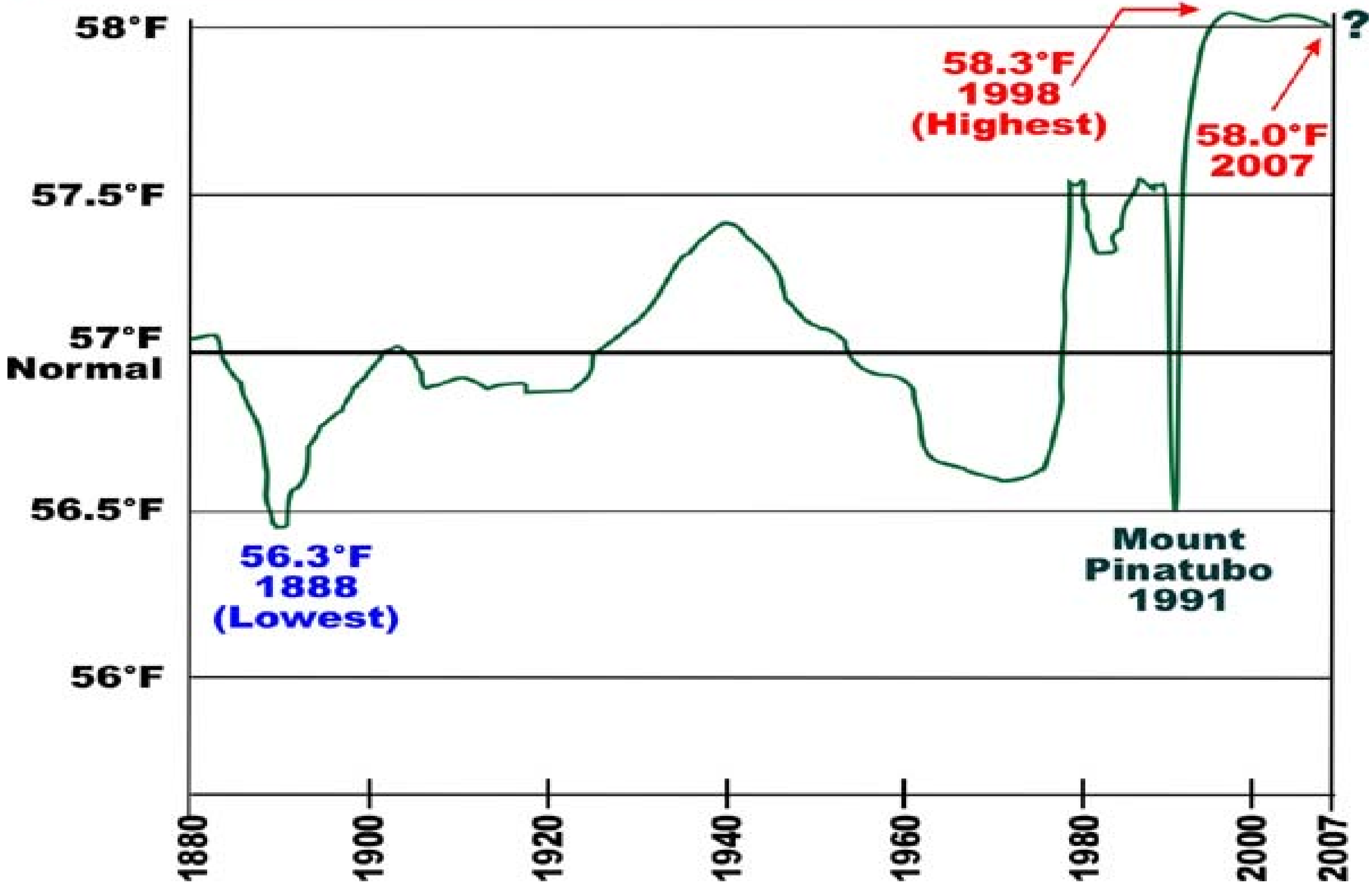
2007 Electric Integrated Resource Plan
Fourth Technical Advisory Committee Meeting
March 28, 2007

Randy Barcus


GLOBAL TEMPERATURES
(2500 B.C. TO 2007 A.D.)
MOUNT PINATUBO ERUPTION (Philippines)
1.1 Degree F. Rapid Cool Down (June 1991 to March 1992)
Global Temperature Went From 0.6 Degrees Above Normal
To 0.5 Degrees Below Normal.
1100 B.C.
Hebrew Exodus From Egypt
Only Scattered Volcanic Eruptions
VERY WARM
2200 B.C.
WARM
Sudden Cool Down
Sudden Cool Down
79 A.D. Vesuvius Erupts Pompeii Destroyed in Italy
4 B.C. Birth of Christ
0 A.D.
Roman Empire
WARM
Viking Explorations (Reached NE Canada)
Few Eruptions
Sudden Cool Down
1300 A.D.
WARM
Big Eruptions
1982 El Chichon Mexico
1991 Mount Pinatubo Philippines
1998 58.3°F
Fewer Eruptions
Now 58°F
1883 Krakatoa Indonesia
1851 Pelee Martinique
1845 Nevado del Ruiz Columbia
?
57°F Normal
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
200
400
600
800
1000
1200
1400
1600
1800
2000
At Least 10 Eruptions in Italy, Pacific and Alaska
Nomanic Time (Era of Great Migration)
25 Eruptions Pacific, Columbia, Italy & Iceland
Grecian Empire
COLD
Vesuvius Etna Italy
250 B.C.
35 Volcanic Eruptions
535-550 Krakatoa, Indonesia and at least 10 other eruptions
DARK AGES
COLD
55 Eruptions
1335-1360 24 Eruptions (Italy, Pacific, Alaska and Iceland)
"LITTLE ICE AGE"
VERY COLD
At Least 90 Major Eruptions (4 in 1660 alone)
1815 Mt. Tambora Indonesia
1792 Unzen Japan
1783 Lakagigar Iceland
1772 Papadanyan Indonesia
1741 Vesuvius Italy
1586 Kelut Indonesia
1607 Jamestown Founded (SE Virginia)
56.3°F?
Whenever SOLAR RADIATION has DECREASED and VOLCANIC ACTIVITY has INCREASED, global temperatures SUDDENLY PLUMMET, often within weeks or months.
2500 B.C. To 0 A.D.
0 A.D. To 2007
AT LEAST 75 MAJOR TEMPERATURE SWINGS IN THE LAST 4,500 YEARS!
Chart prepared by: Climatologist Cliff Harris & Meteorologist Randy Mann

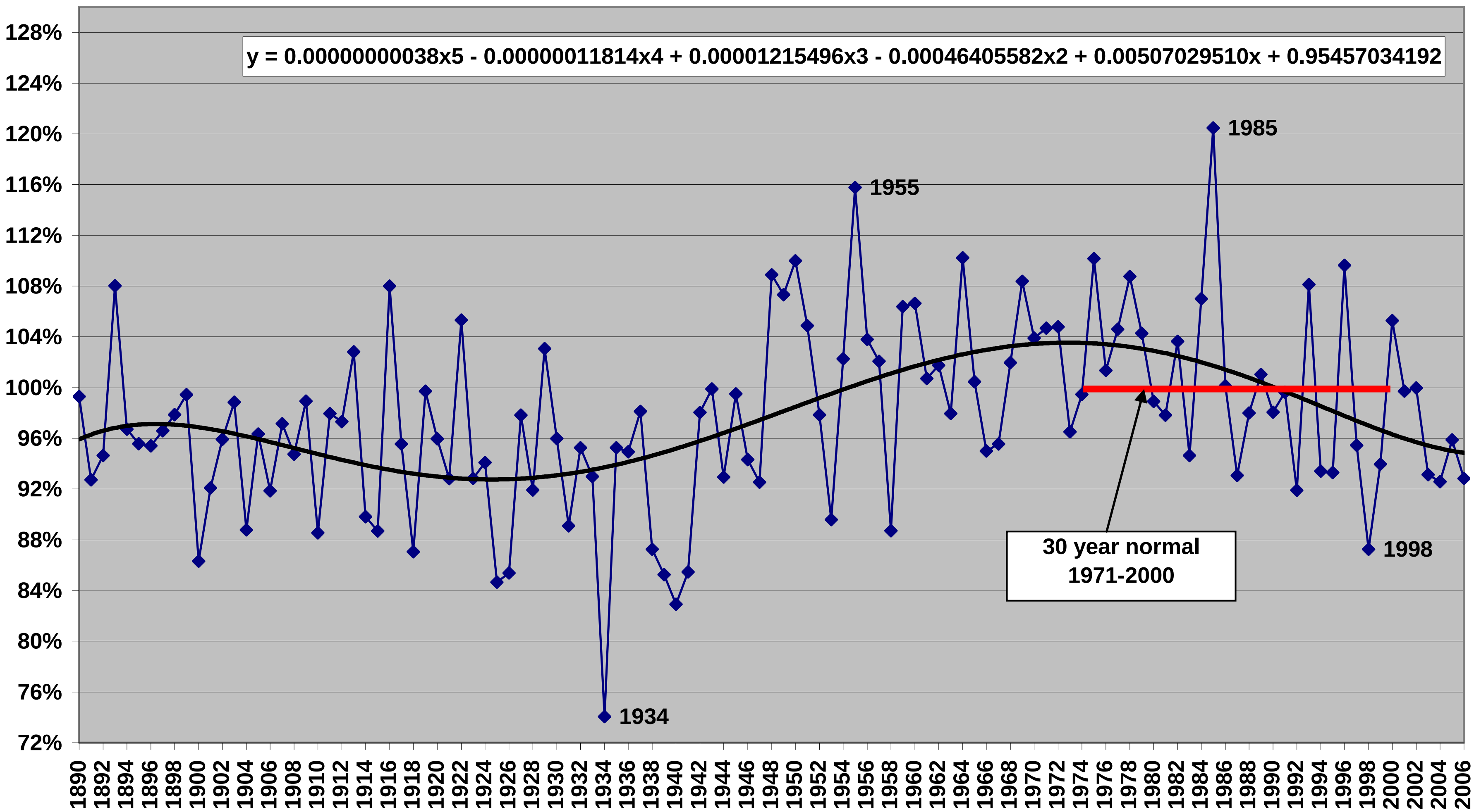
GLOBAL MEAN TEMPERATURE GRAPH SINCE 1880

Prepared by Cliff Harris and Randy Mann

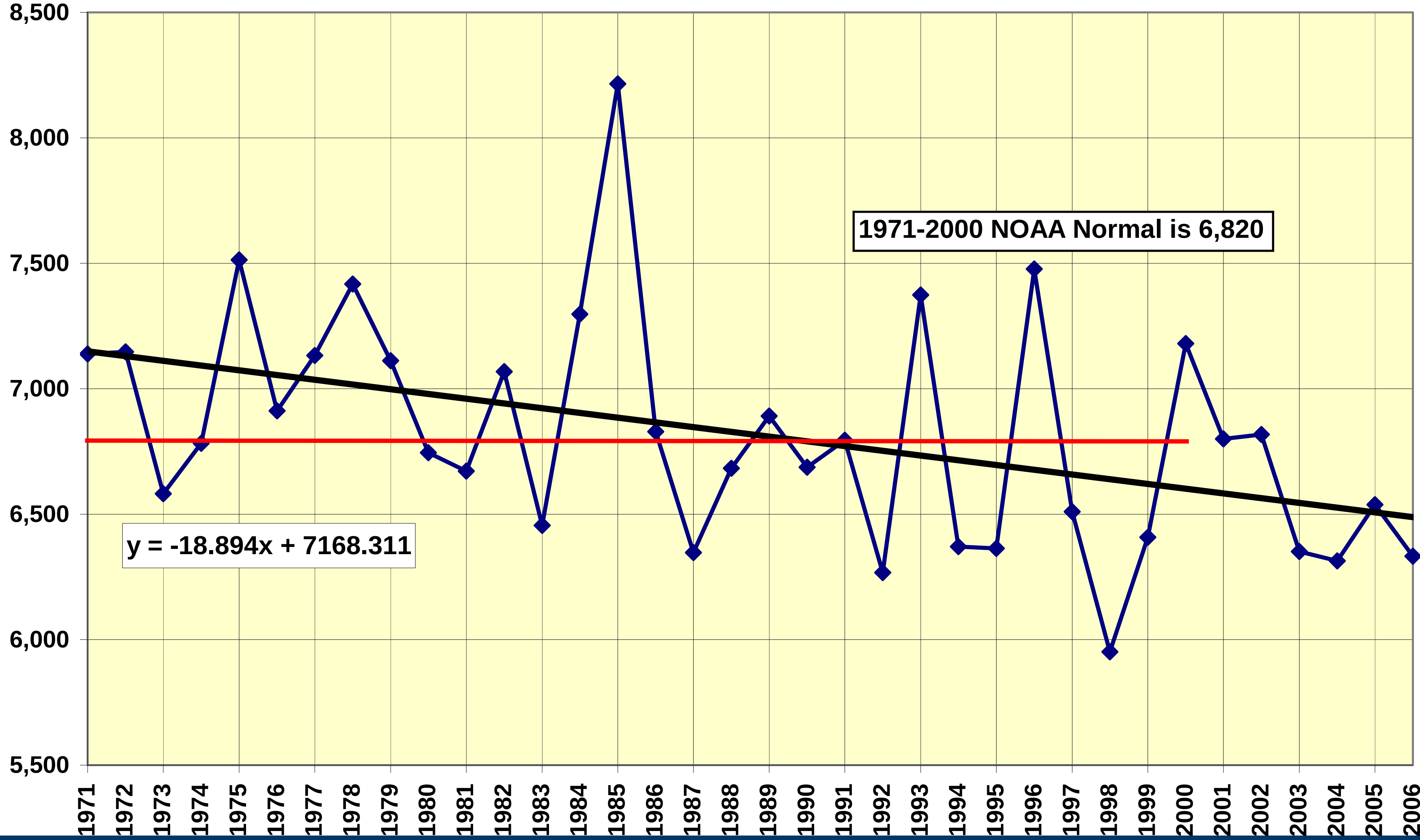


For Discussion Purposes Only

Annual Heating Degree Days, Percent of Normal - Spokane, WA

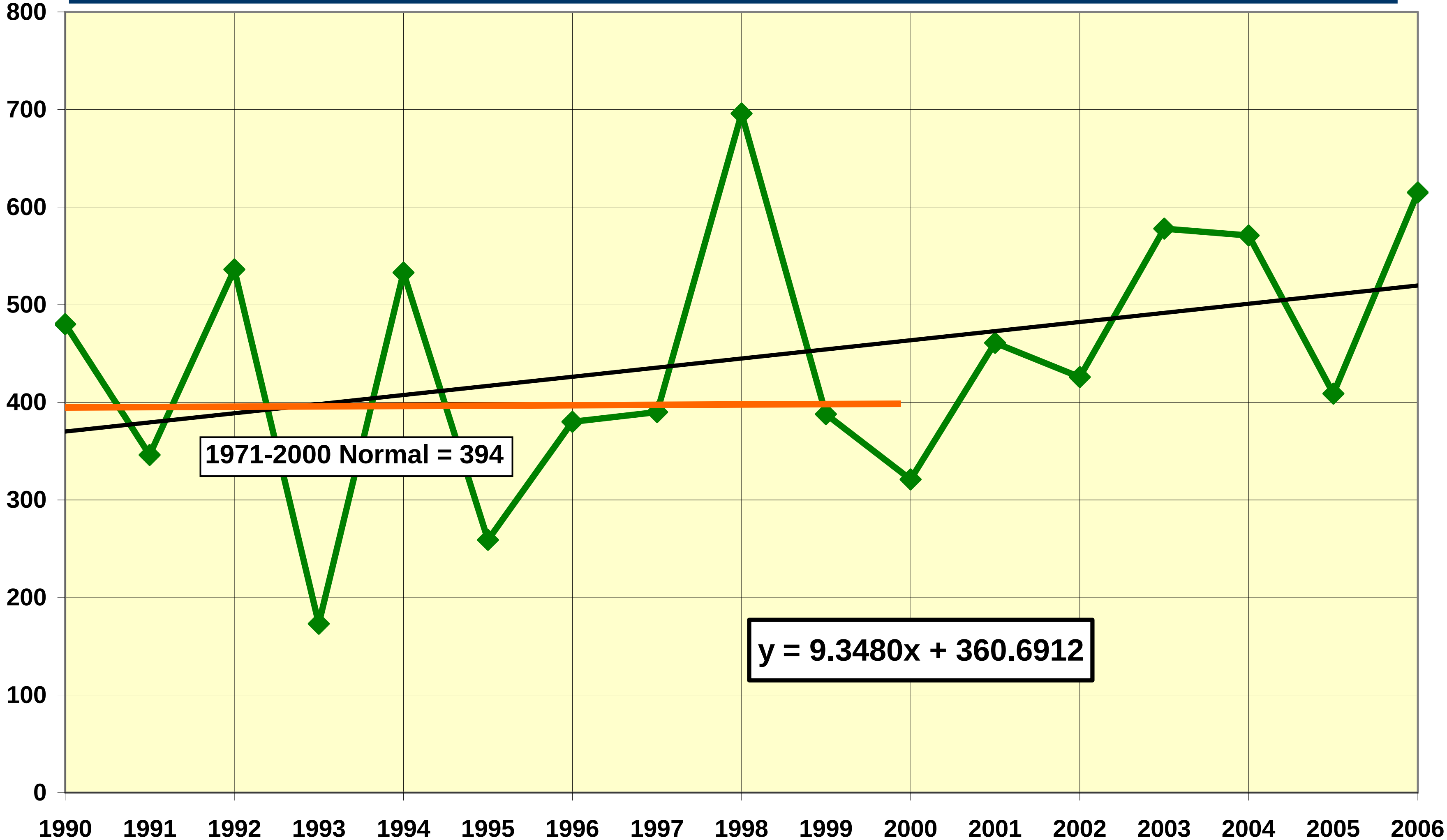


1971-2006 Spokane HDD Trend

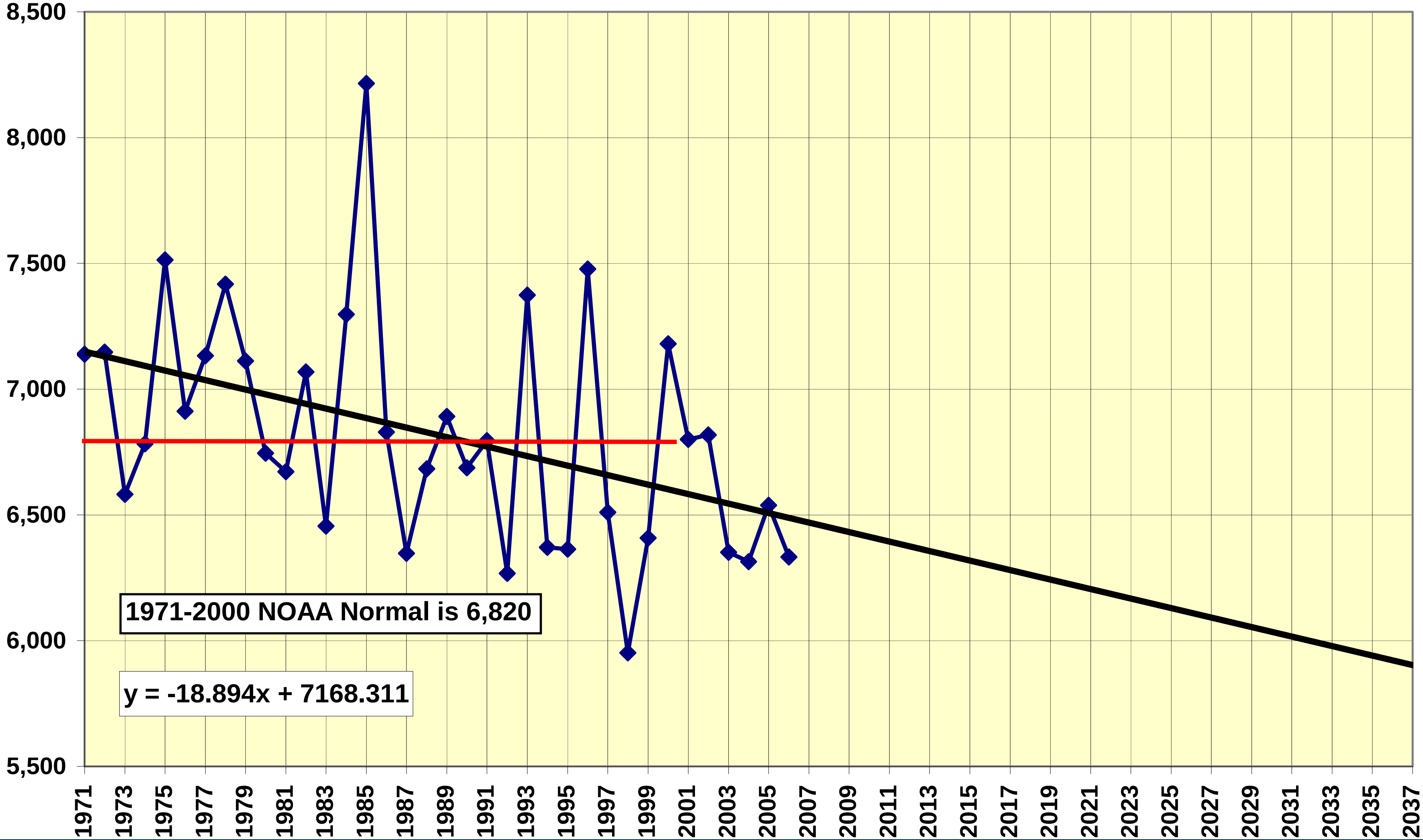


For Discussion Purposes Only

1990-2006 Cooling Degree Day Trend



1971-2006 Spokane HDD Trend



For Discussion Purposes Only

AVISTA

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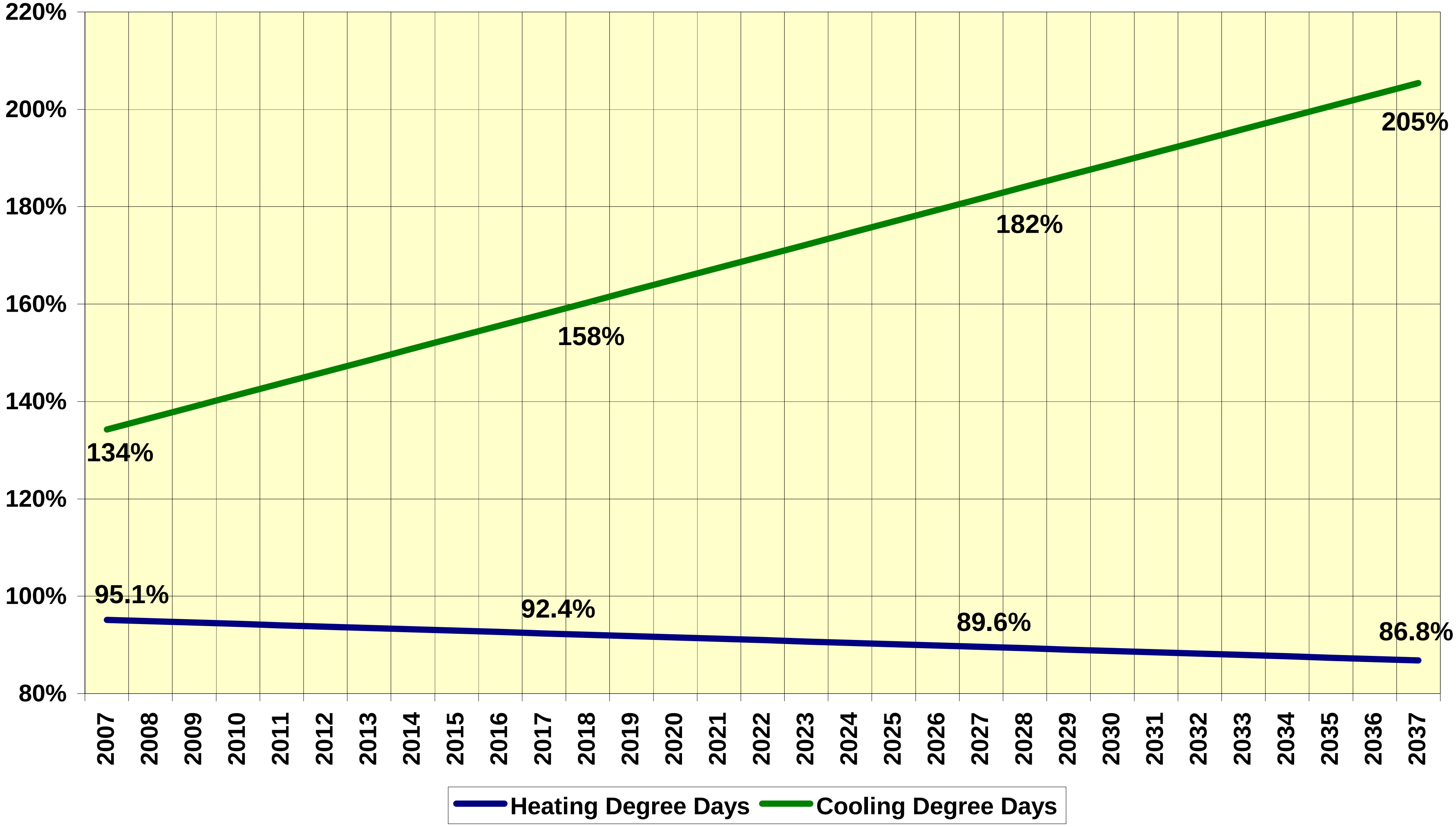
Global Warming Degree Day Trends (2007-2037)



Preliminary Load Forecast Impacts

Electric Load (semi-rough estimates)

▪ July/August	2007	+10 aMW	~0.9%
	2017	+18 aMW	~1.3%
	2027	+26 aMW	~1.6%
	2037	+34 aMW	~1.7%
▪ December/January	2007/8	-18 aMW	~(1.4%)
	2017/8	-29 aMW	~(1.8%)
	2027/8	-40 aMW	~(2.1%)
	2037/8	-51 aMW	~(2.1%)

Natural Gas Firm Load (very rough estimates)

▪ Calendar	2007	-3%
	2017	-5%
	2027	-7%
	2037	-9%

Discussion/Questions

The purpose of this presentation was designed to answer one simple question:
If temperatures rise during the long-range forecast horizon consistent with the science on global warming, how much would Avista's loads shift?

At this time, Avista's regulatory requirements indicate use of the National Oceanic and Atmospheric Administration's official 30-year normal.
Were that regulatory requirement to change, Avista would produce consistent regulatory filings based on the modified rules.

Heritage Project Update

2007 Electric Integrated Resource Plan

Fourth Technical Advisory Committee Meeting

March 28, 2007

Bruce Folsom

Heritage Project – Demand Response Initiative

Maintain focus on targets and existing DSM programs while

- assessing best practices status
- surveying and implementing:
  - expanded options and
  - expanded delivery mechanisms

Continue the Company's legacy:

- resource acquisition through least-cost demand response programs
- innovate, educate and communicate on customers' behalf

Heritage Project (Continued)

Acquire sufficient energy and demand savings to delay a thermal plant as long as financially possible

- through a comprehensive, state-of-the-art demand response initiative
- by examining and implementing:
  - expanded energy efficiency programs,
  - peak shaving programs,
  - consideration of time-of-use schedules and other pricing options,
  - and all other options (e.g., T&D efficiency),
- in a manner that is sustainable and fiscally credible

…pursue the most efficient portfolio (supply and demand response) that we can possibly deliver

Heritage Project Status

Road Maps completed:

- Energy Efficiency Task Force
- Load Management Task Force
- Transmission and Distribution Task Force
- Each has very different flavor

Next Steps:

- Bring on additional staff
- Design and implement 2007 enhanced and new programs
- Continue Analytics
- Plan for 2008 capital needs…"Blueprint for the Future"
- Implement outreach and communication program

Energy Efficiency Road Map

- Started with a very strong platform of energy efficiency services
- Inventoried macro-list
- Enhanced programs and new programs to be launched in 2007
- Focus on education and outreach supported by new programs
- Oregon Achievement Plan
- Avista Model Plan

Load Management Road Map

- Avista faces high peak costs, but different than other parts of country
- Technology costs continue to fall and technology can now be integrated
- Decisions are how best to apply which technology—“prices to devices”
    - Infrastructure needs
    - Defining system and hardware requirements
    - Assessing costs/benefits
    - Testing and experimenting with customer acceptance
- Five projects identified for 2007, after options were scrutinized
- Framework for 2008+ activities

Transmission & Distribution Road Map

- Focus to be on internal rates of return
- Nine projects identified for review
- Three specific improvements are underway or in the analysis stage

Analytics Road Map—Representative Example

Resource Value Component Summary

(All calculations assuming an illustrative flat load)

Component	10 yr Energy ($/MW)	20 year Energy ($/MW)	Capacity[5] ($/kW)
Avoided cost of energy	$49[1]	$57[1]	
Avoided emissions cost	$2[2]	$4[2]	
Reduction in energy cost volatility	$16[3]	$18[3]	
Reduction in T&D losses	$4[4]	$5[4]	
Value of deferred gen capacity			$300
Value of deferred T&D capacity			$105
TOTAL COST	**$71**	**$84**	**$405**

1. The flat load assumption is a simplification of a calculation that will be based upon a full 8760-hour stream of avoided energy costs.
2. It is likely that this fixed emissions cost adder will be applied until the impact of pending or likely legislative impacts can be modeled.
3. This is an adder to reflect the difference between the expected value of the avoided cost stream and the 95% confidence interval.
4. Based upon a 6.5% T&D loss assumption. In practice this will be applied to each individual hour of the 8760-hour avoided energy cost stream.
5. Capacity value is based upon the contributions of a resource to system-coincident peak load reduction. Presently we are moving forward based upon a winter space heating-driven system peak assumption.

Communications Planning

Sustained (3-5 year) outreach campaign

- Stage new roll-outs
- To each program, its best tool
  - Media release?
  - Paid media?
  - Other

Communications to all Company employees

Employee training in specific areas that have direct customer contact

- prepare employees to continue to inform customers about
  - energy conservation, and
  - available programs and rebates.

Current Avista Energy Efficiency Programs

Residential/Limited Income	Commercial/Industrial/Institutional
High-efficiency natural gas furnaces/boilers	Site Specific (any measure)[1]
High-efficiency heat pumps	Efficient lighting and occupancy sensors
High-efficiency variable speed motors	Food service equipment
High-efficiency water heaters	Rooftop HVAC maintenance (AirCare Plus)
Electric to natural gas heat	Variable frequency drives
Electric to heat pump	LEED certification
Electric to natural gas water heaters	Multi-family, replace electric DHW with gas
Ceiling/attic, floor and wall insulation	Premium efficiency motors
Windows	Supermarket and grocery store refrigeration
Limited income measures including health/safety	Power management for computer networks
	LED traffic signals
	Refrigerated warehouses
	Efficient spray head installation

[1]The Site Specific program is an all-encompassing offer to provide incentives on any cost-effective commercial and industrial energy efficiency measure. This is implemented through site analyses, customized diagnoses, and incentives determined for savings generated specific to customers' premise or process.

Proposed New Energy Efficiency Programs

Start Time	Residential & Small Commercial/Industrial	Commercial/Industrial/Institutional
1Q07	• Res & Small C&I Quick Hits Program – Something For Everyone Measures – Fireplace Dampers	• C&I Quick Hits Program – Side-Stream Filtration – Energy/Heat Recovery Ventilation (ERV/HRV) – Demand Control Ventilation (DCV) – Steam Traps
2Q07	• Super Efficient Habitat for Humanity (HFH) Homes	
3Q07	• Geographic Saturation Program	• Retro-Commissioning Program • Behavioral Program
4Q07	• Regional Natural Gas Market Transformation Program	• Facilities Model Program (ongoing)

Proposed 2007 Load Management Projects

- Residential Demand Response Pilot
- Small Commercial Demand Response Pilot
- Large Commercial/Industrial Interruptibility
- Avista Facilities Demonstration Project
- Large Commercial/Industrial Distributed Generation

Proposed 2008 Load Management Projects

- Support for Accelerated AMR Build-Out in Washington and AMI in Idaho
- Rate Design
- Demand Response
- Distributed Generation

Transmission and Distribution Road Map

- Secondary Districts
- Substations
  - Substation Size and Location
  - Substation Transformers
  - Substation Lighting and Parasitic Loads
- Feeders and Conductors
  - Feeder Balance
  - Economic conductor analysis
- Distribution Transformers
  - High Efficiency
  - Right Sizing
- Conservation Voltage Reduction (CVR)

T&D Continued

Three specific projects are under way or under consideration:

- Rockford/Latah
- Priest River
- Colville12F2 Reconductor

Customer Benefits

- Lower bills for participating customers
- Reduced costs for general body of customers
- Take some control of the bill in a period of increasing costs
- Interact with the utility; learn of other programs
  - Average monthly billing
  - Low-income rate assistance
  - Consumer programs, *et cetera*
- Helps address a re-awakened environmental focus due to "daily" GHG reports
- Customers like knowing they have options, even if they don't avail themselves of programs
- Satisfaction that their utility is "socially responsible"
- Conservation is a root value in our society with strong support

Company Benefits

- Implement IRP
  - Documents technical and achievable savings
  - Stakeholder involvement…meet with the expert public, the opinion leaders
- Acquire lower cost resources
- Potential for cost savings
- Customer touches
  - Customers and the community like good news
  - Provides for proactive customer assistance
  - Increases satisfaction ratings
- More information for large resource acquisition decisions
  - National and state policy (e.g., emission requirements)
  - Technology
- Reduced pressure on, or alternatives for, the capital budget?

2007 Implementation Items

- Energy Efficiency
  - To existing 21 programs, several enhanced and new programs/measures
- Load Management
  - Two pilots (res and com) at Liberty Lake and Sandpoint
  - Large customer interruptibility and distributed generation
- Transmission and Distribution
  - Examining nine potential projects and 3 are work in progress
- Costs are based on each set of unique circumstances--
  - Energy efficiency, the avoided cost of a base load plant or purchase
  - Load management, the cost of peaking resources (e.g., gas turbines)
  - T&D, the internal rate of return (IRR) compared to other capital projects
- Communications
  - External and internal

Overall Key Points

- Focus on existing DSM targets while assessing best practices…
- Continue the Company's legacy: innovation/education on customers behalf
- Acquire sufficient energy and demand savings through a comprehensive, state-of-the-art demand response initiative
  - by examining and implementing:
    - expanded energy efficiency programs,
    - peak shaving/shifting programs,
    - and all other options (e.g., T&D efficiency),
  - in a manner that is sustainable and fiscally credible

Preferred Resource Strategy Criteria & Analysis

2007 Electric Integrated Resource Plan

Fourth Technical Advisory Committee Meeting

March 28, 2007

James Gall

Linear Programming Decision Support Systems (LP DSS)

- Used outside of utility industry for decades
  - Power utilities are "behind the times" in adopting LP DSS
- Support highly complex decision-making with single- and multiple-objective functions
- Utility portfolio development is complicated & expensive
- Requires advanced portfolio and market analyses
- Avista used LP DSS starting with 2003 IRP
  - The PRS Model
  - Enhancements added in each IRP cycle

Preferred Resource Strategy (PRS) Methodology

- Linear program that solves for the optimal resource strategy to meet resource deficits over planning horizon.
- Model selects its resources to reduce cost and risk.

Minimize:

(X_1* NPV of Total Cost$_{2008\text{-}2017}$ + X_2*Absolute Deviation Power Supply Costs$_{2017}$* F) + (X_1*(10% NPV of Total Cost$_{2018\text{-}2027+}$ + X_2*10% Absolute Deviation Power Supply Costs$_{2027}$ * F)

Subject to:

Capacity Need +/- deviation

Energy Need +/- deviation

Wash St. Renewable Portfolio Standard

Resource Limitations and Timing

Capital Spending

Where:

X_1 = Weight of cost reduction (between 0 and 1)

X_2 = Weight of risk reduction (1 - X_1)

F = Factor to equate Risk and Cost at 50/50 study

Requirements for PRS Model (Inputs)

- Expected load & resource balance for next 20 years
- 20 year by 300 iteration matrix of resource values
  - Avista's current resource portfolio cost
  - Each new resource alternatives market value (electric price less fuel costs, variable O&M, and emissions offsets "taxes")
- Conservation estimates
- Generation capital costs, fixed operating costs, transmission costs, revenue requirements
- Availability assumptions (how much and when)

What Does The PRS Model Tell Us?

- Specific quantity of resource selection and timing
- Expected power supply cost for each year
- Expected risk or volatility in expected power supply costs for each year
- Expected power supply-related rate impacts
- Capital requirements and cash flow expectations
- Cost ($/MWh) in excess to market to meet capacity needs
- Illustrates the trade off between risk and cost of different portfolios

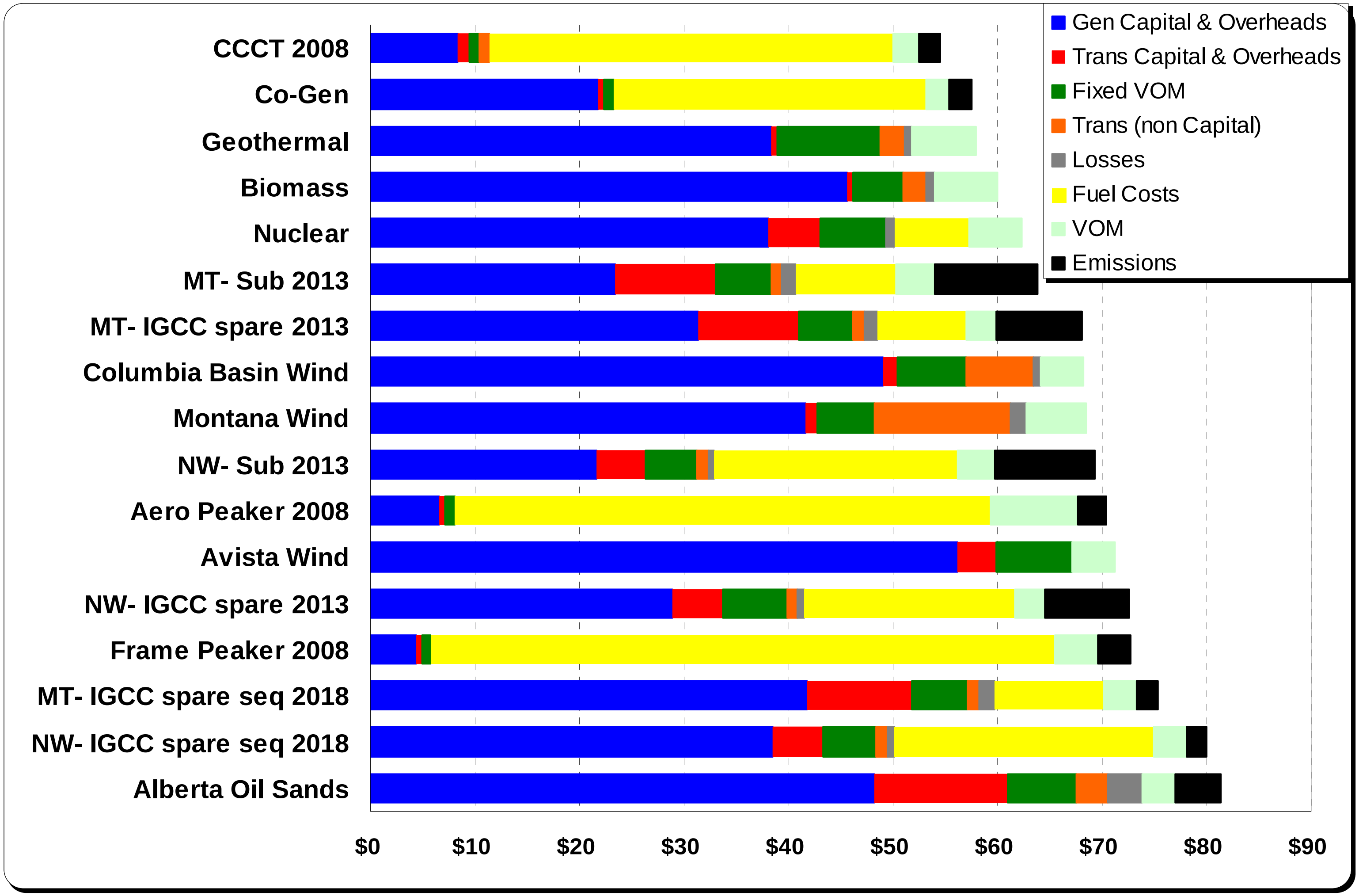
The PRS Model Does Not Make the Decision

PRS Model Assumptions

- No non-sequestered coal or nuclear are permitted (Base Case)
- No more than 400 MW of wind between 2008 and 2017
- No more than 600 MW of wind between 2008 and 2027
- Must meet WA RPS by building resources or buying green tags at the 4% revenue requirement cap
- No capital spending constraints (Base Case)
- May purchase fixed-price gas contract for CCCT plants
- May purchase/sell in short-term market for annual balancing
- Must approximate (i.e., not over-/under-build) needs

Short List Resource Options

(Levelized $2007 "real"/MWh)



Resource Capital Costs *(Excludes Transmission)*

Resource Option	2007$/kW		Resource Option	2007$/kW
CCCT	786		Coal – Subcritical	1,906
SCCT-Aero	628		Coal – Supercritical	2,004
SCCT-Frame	419		Coal – Ultracritical	2,010
Wind	1,884		Coal – CFB	2,155
Geothermal	4,000		IGCC	2,378
Biomass	3,500		IGCC - w/Spare Gasifier	2,524
Oil Sands	3,963		IGCC – Sequestered	3,045
Nuclear	3,100		IGCC - Sequestered w/Spare Gasifier	3,232
Small Co-Gen	2,100			

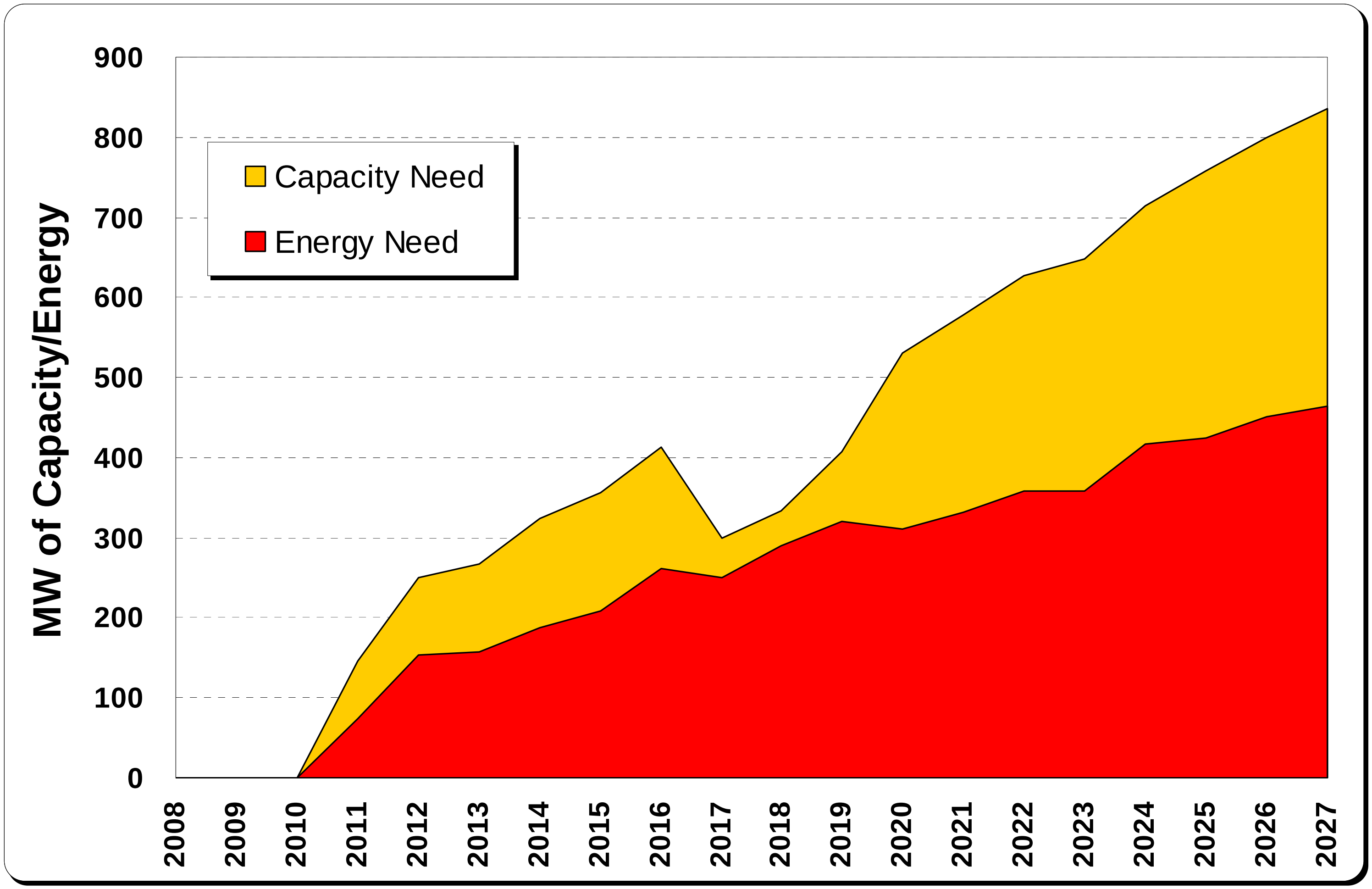
Gas-Fired Combined Cycle With Fixed Gas

- Medium- to long-term fixed-price gas contract, or
- Could be coal gasified into pipeline-quality gas
  - Provide a significant new source of gas supply
  - Create a sequestered IGCC plant w/o operational trade-offs
    - Remote locations, altitude penalties, gasifier reliability
- Model is flexible in modeling any type of fixed gas price
- Fixed versus spot gas price assumptions

Year	Fixed	Spot	Year	Fixed	Spot
2012	6.75	5.35	**2022**	9.52	8.93
2018	8.3	7.14	**2027**	11.31	11.28

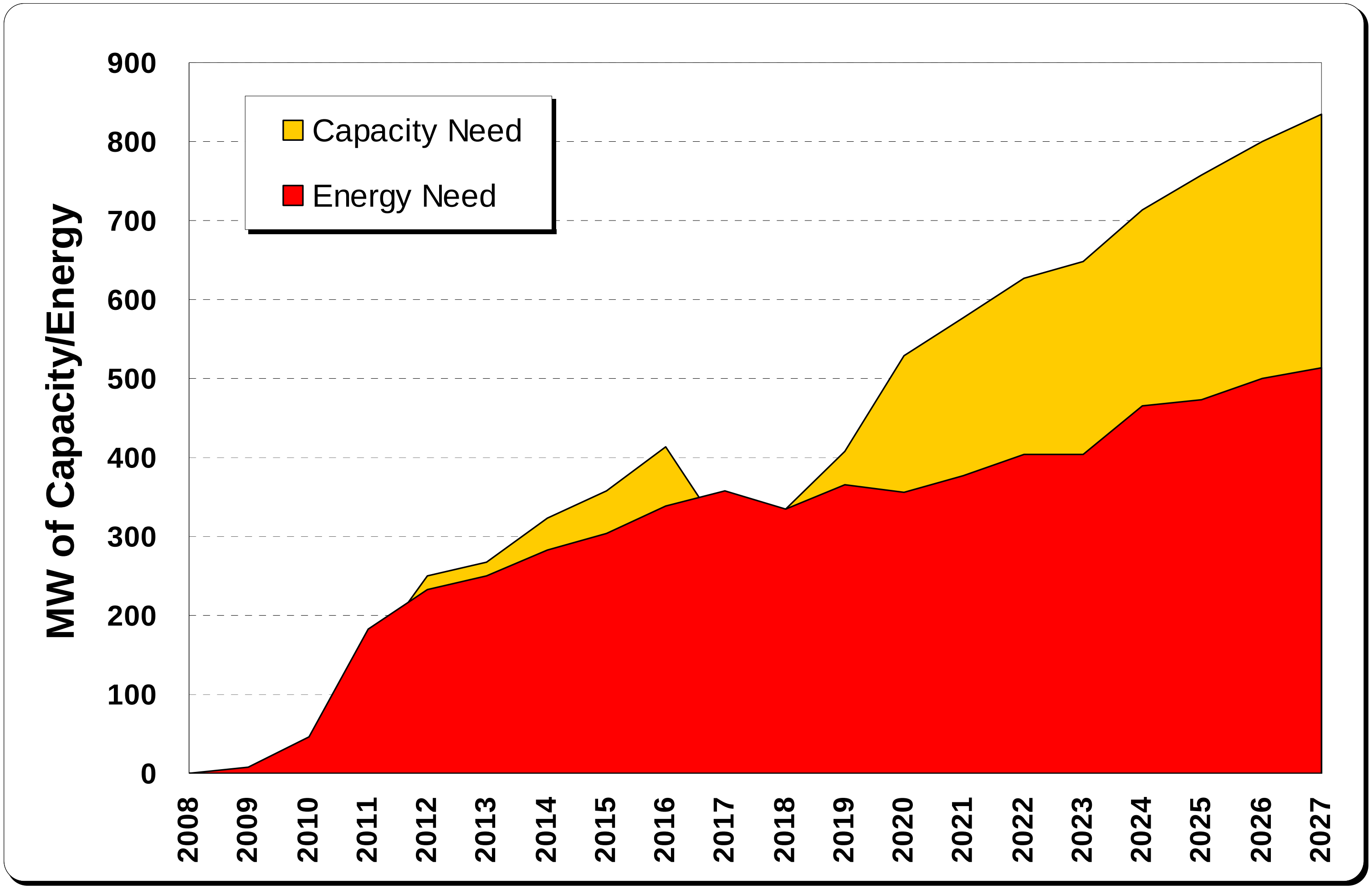
- Intent of this resource is to illustrate the ability to reduce power cost risk without building a coal resource directly

Avista's Annual Average Resource Need



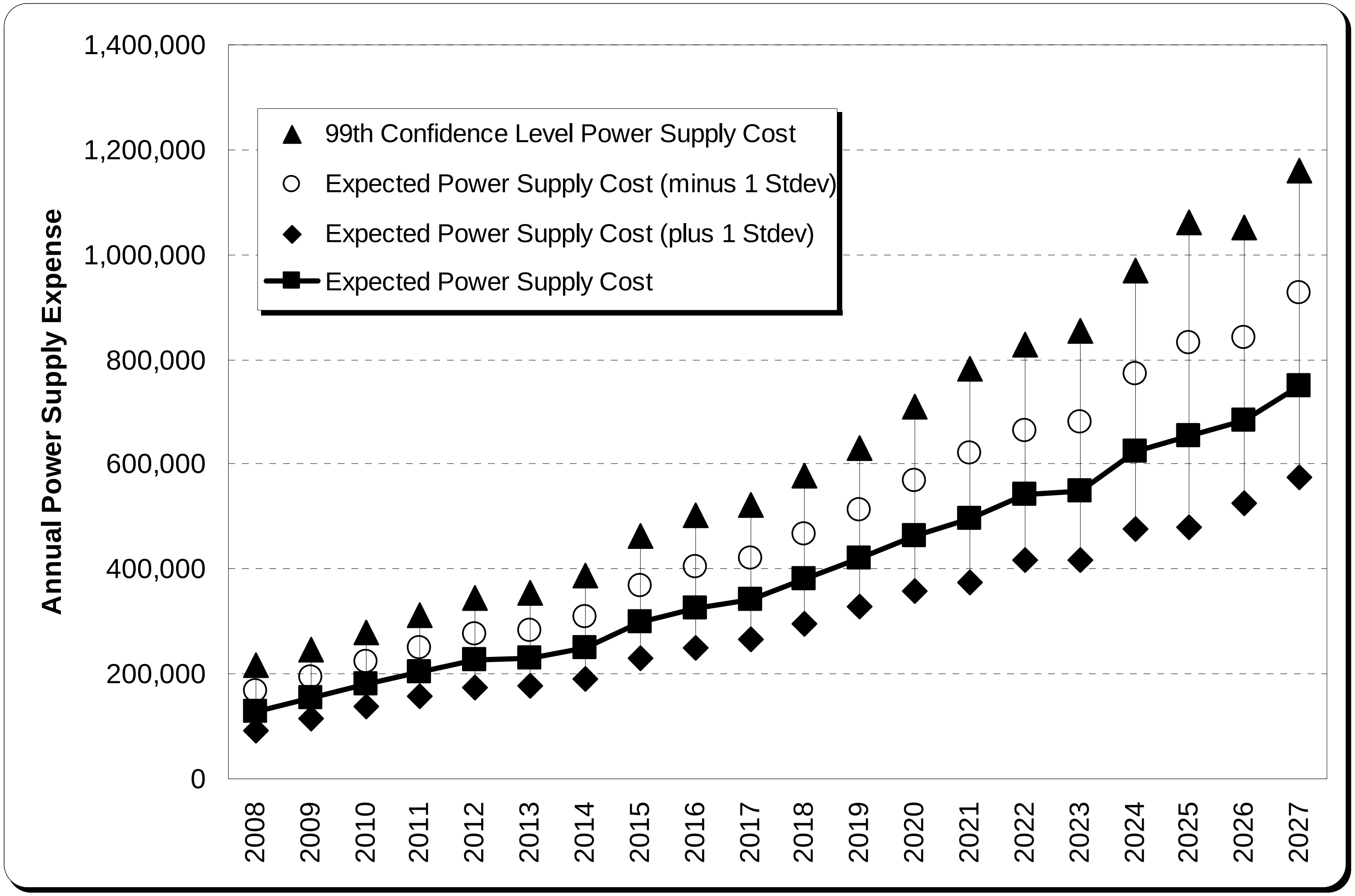
Excludes Additional Conservation

Avista's Annual Average Resource Need (excluding Q2)



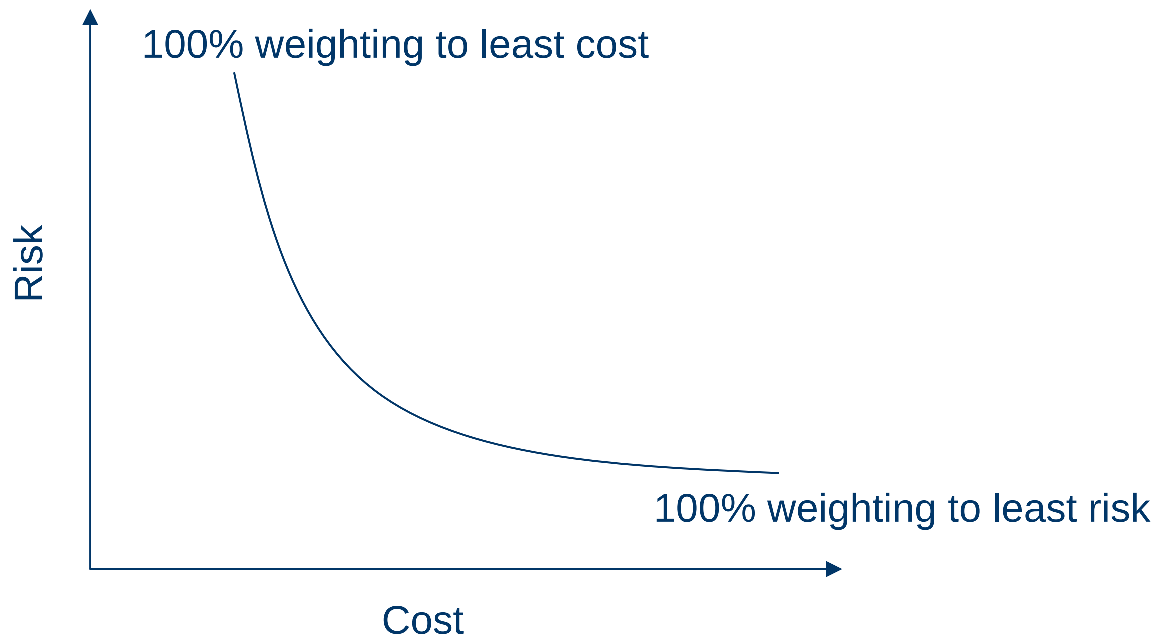
Excludes Additional Conservation

Current Portfolio Costs and Risk

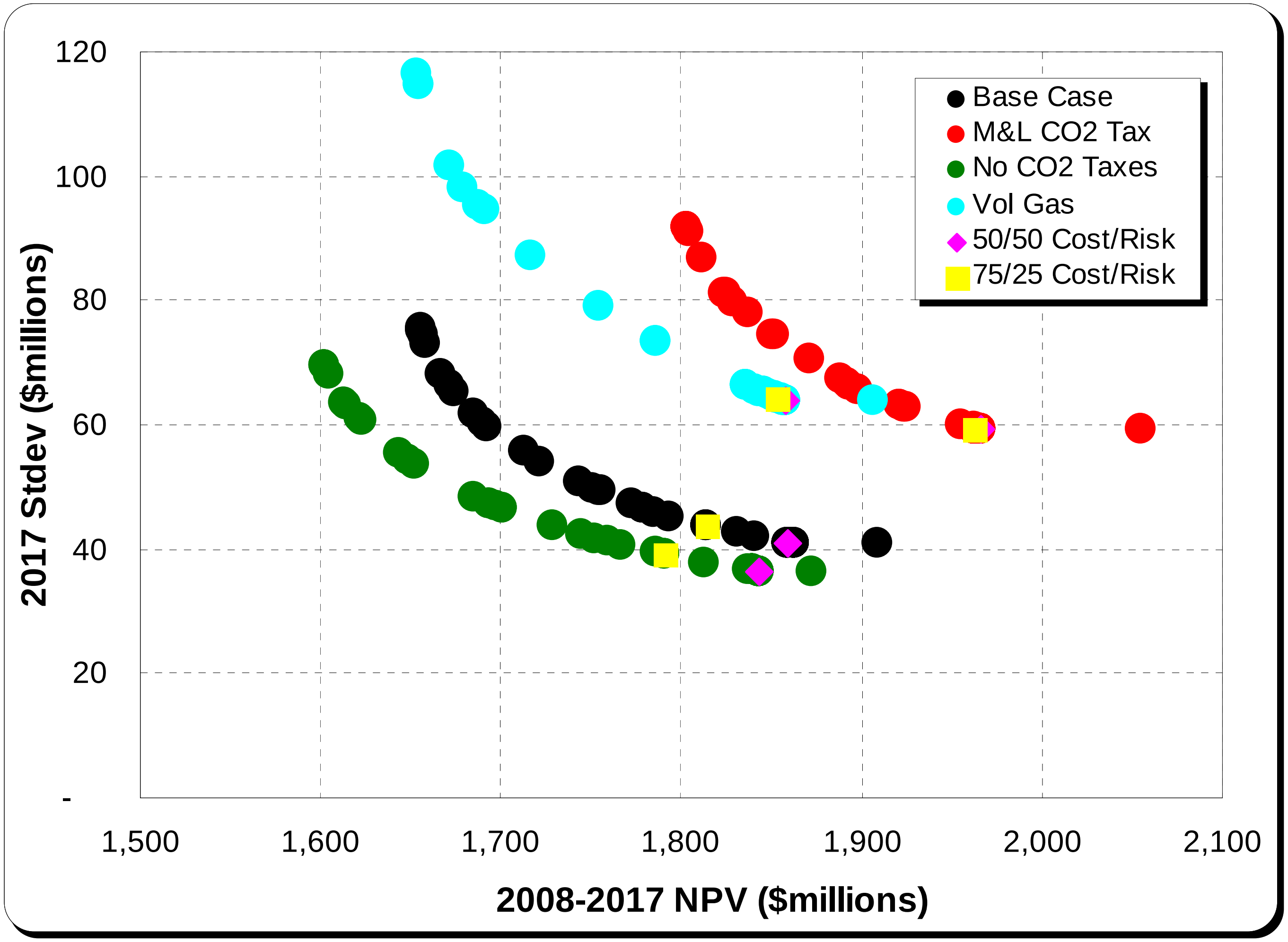


What is the Efficient Frontier?

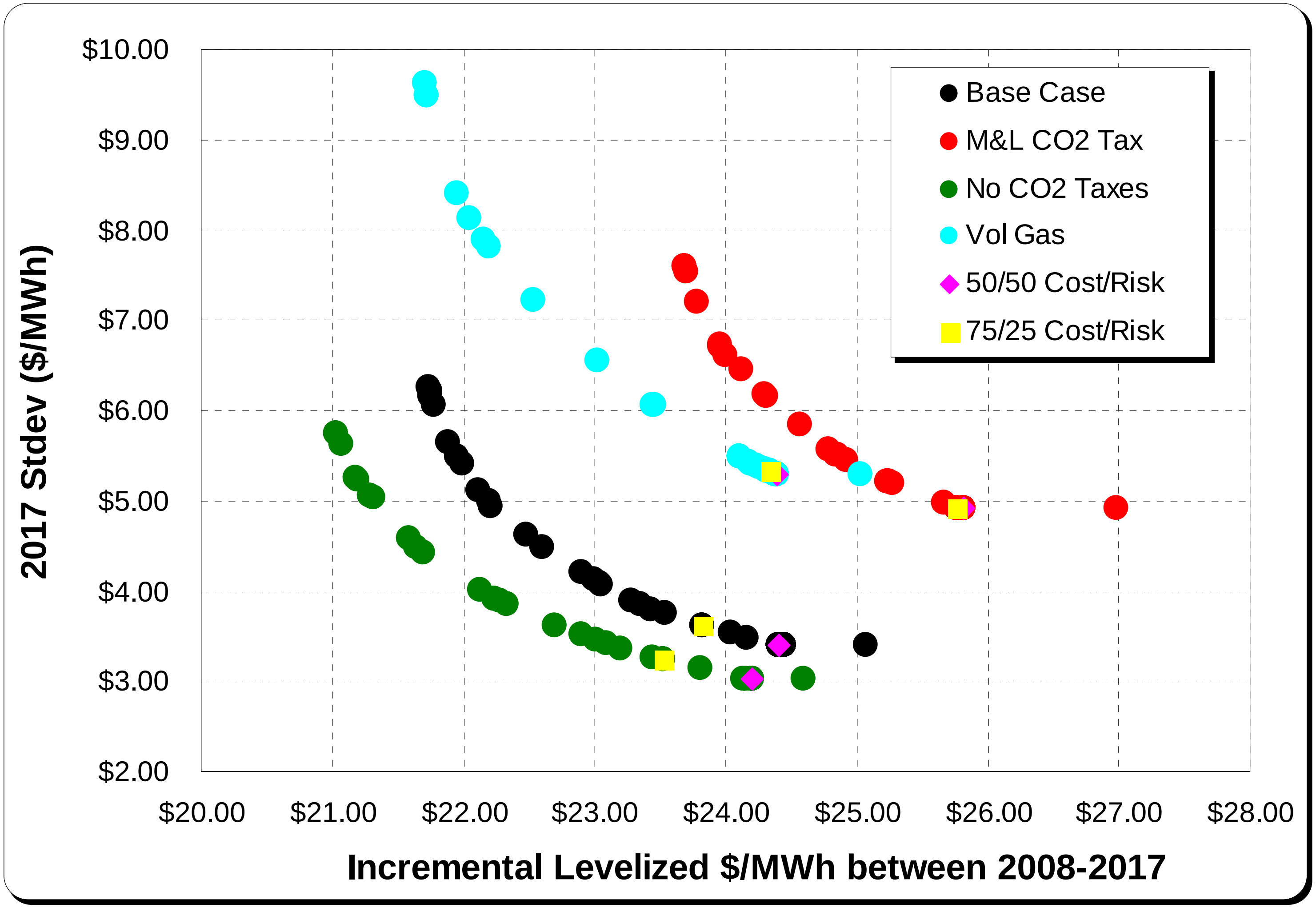
- Demonstrates the trade off of cost and risk
- Difficulty: how much additional cost are we willing to pay to reduce risk



Efficient Frontiers

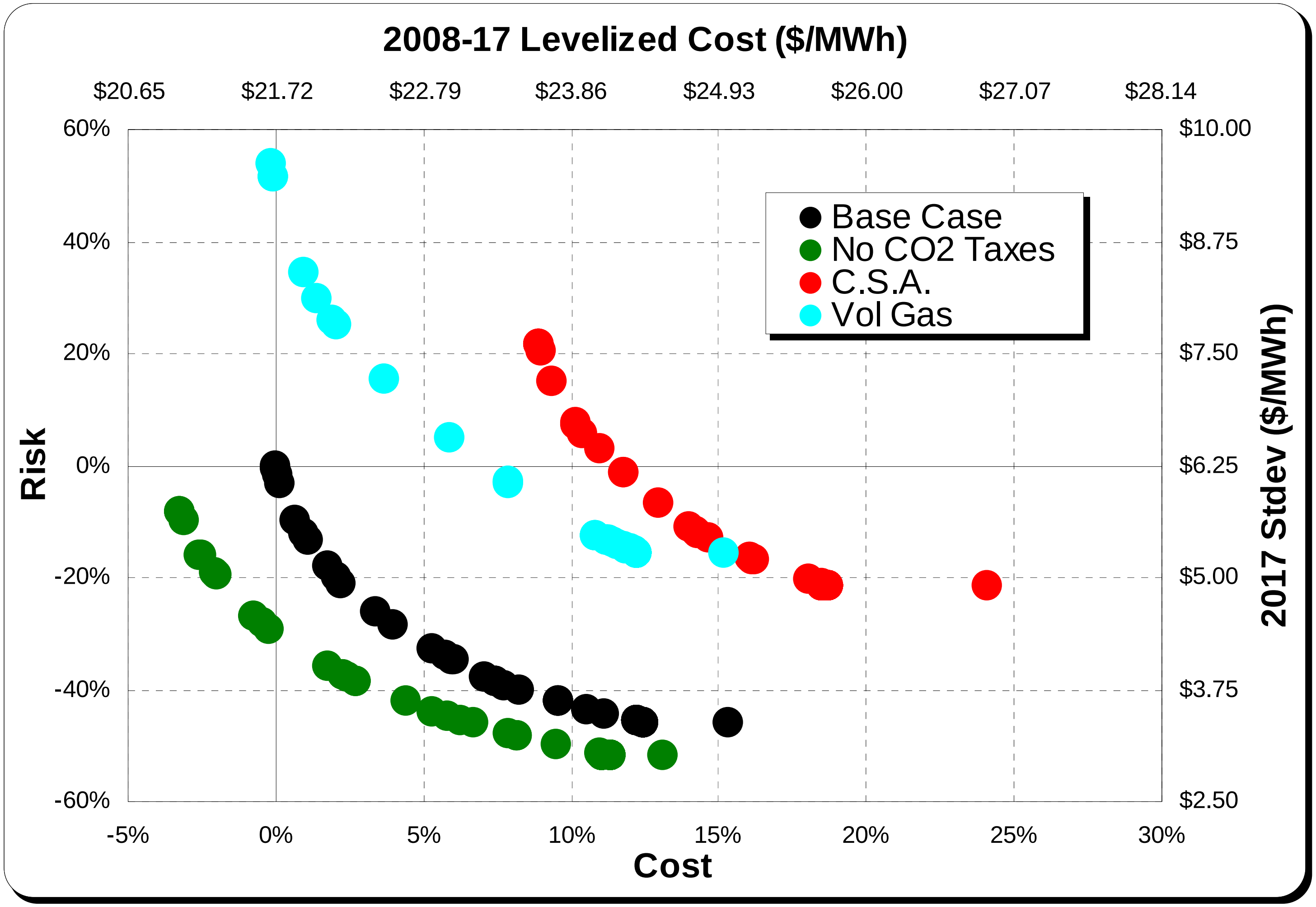


Efficient Frontiers (Incremental $/MWh)

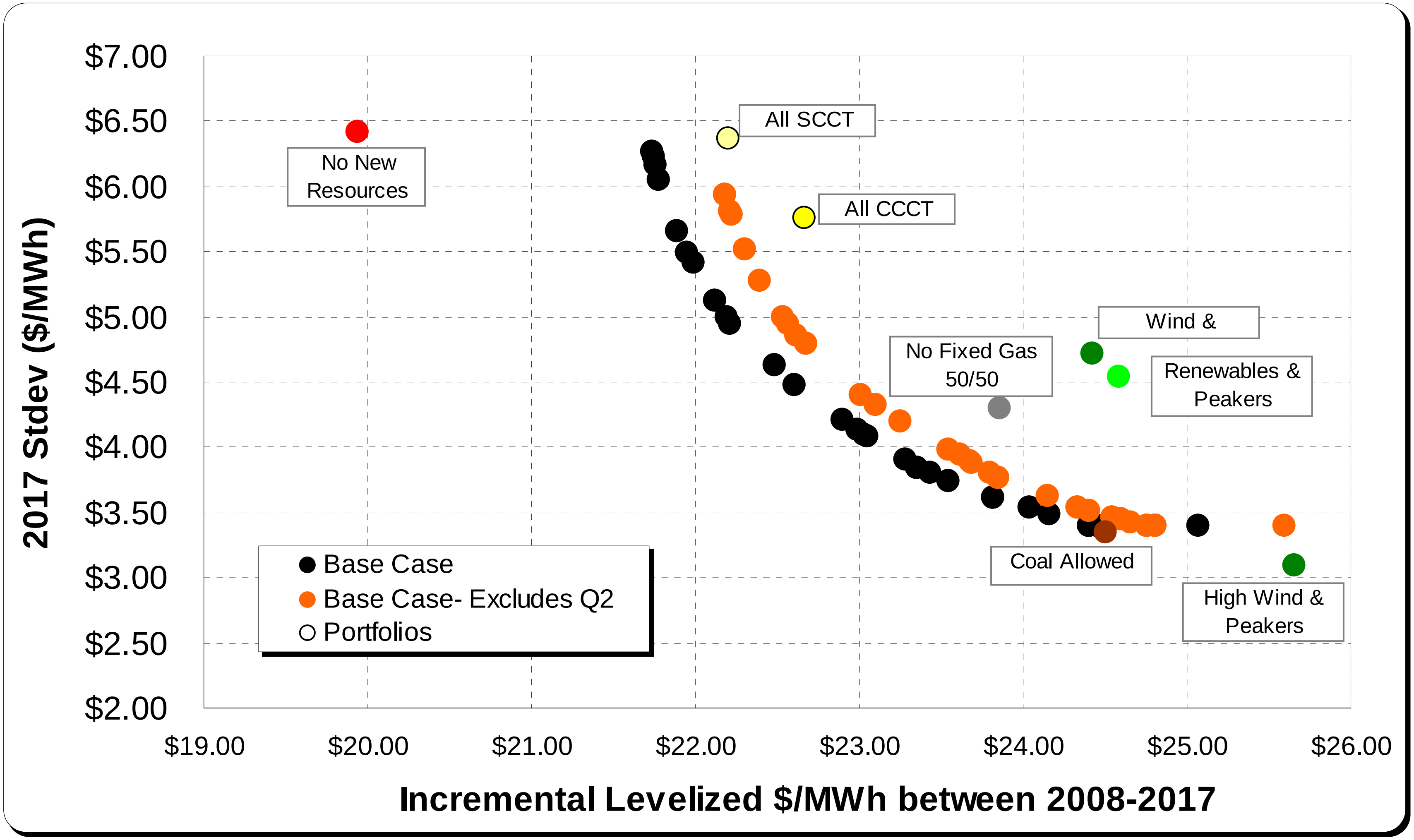


15

Efficient Frontiers (Incremental $/MWh & Percent Change)



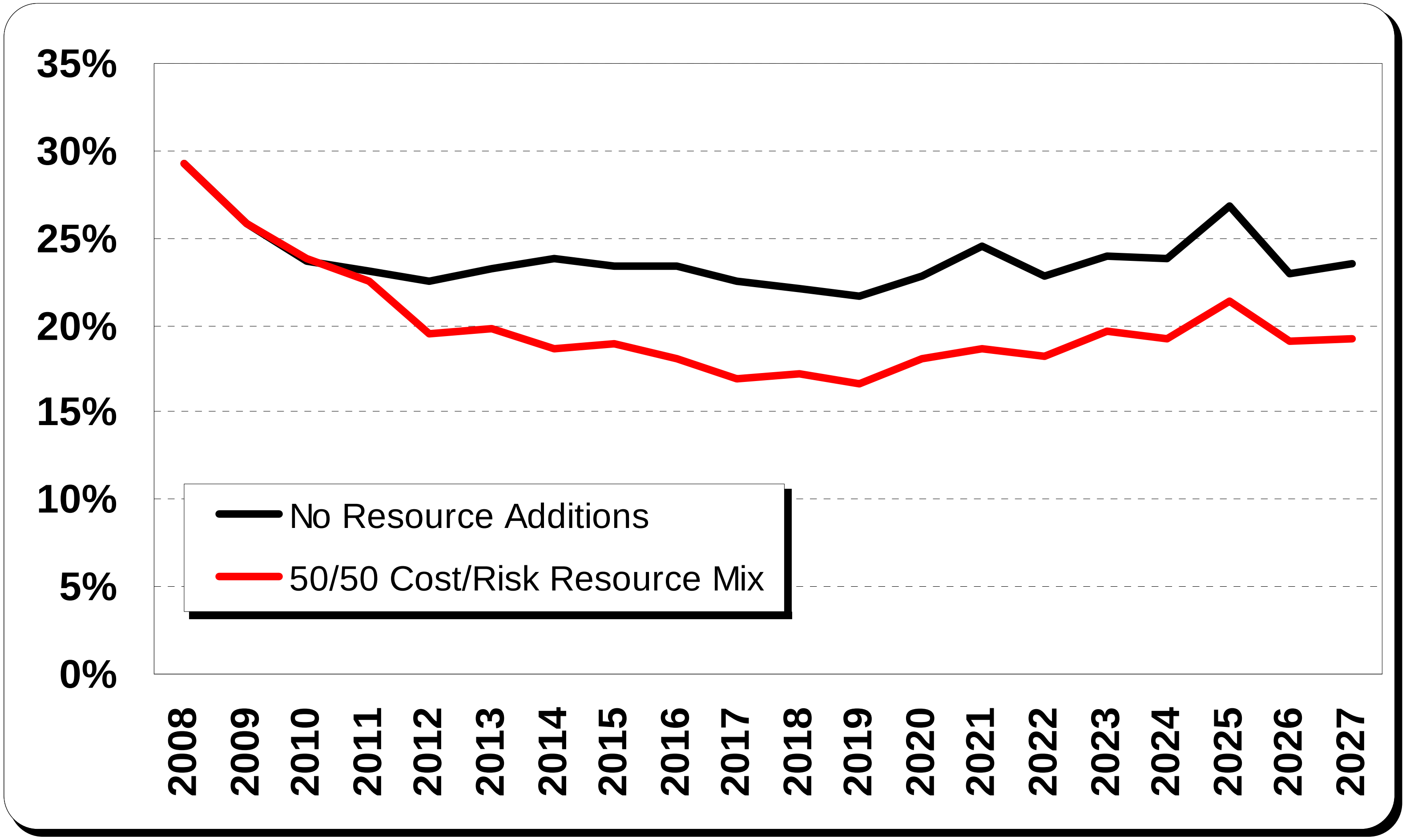
Base Case Options & Portfolios Efficient Frontiers (Incremental $/MWh)



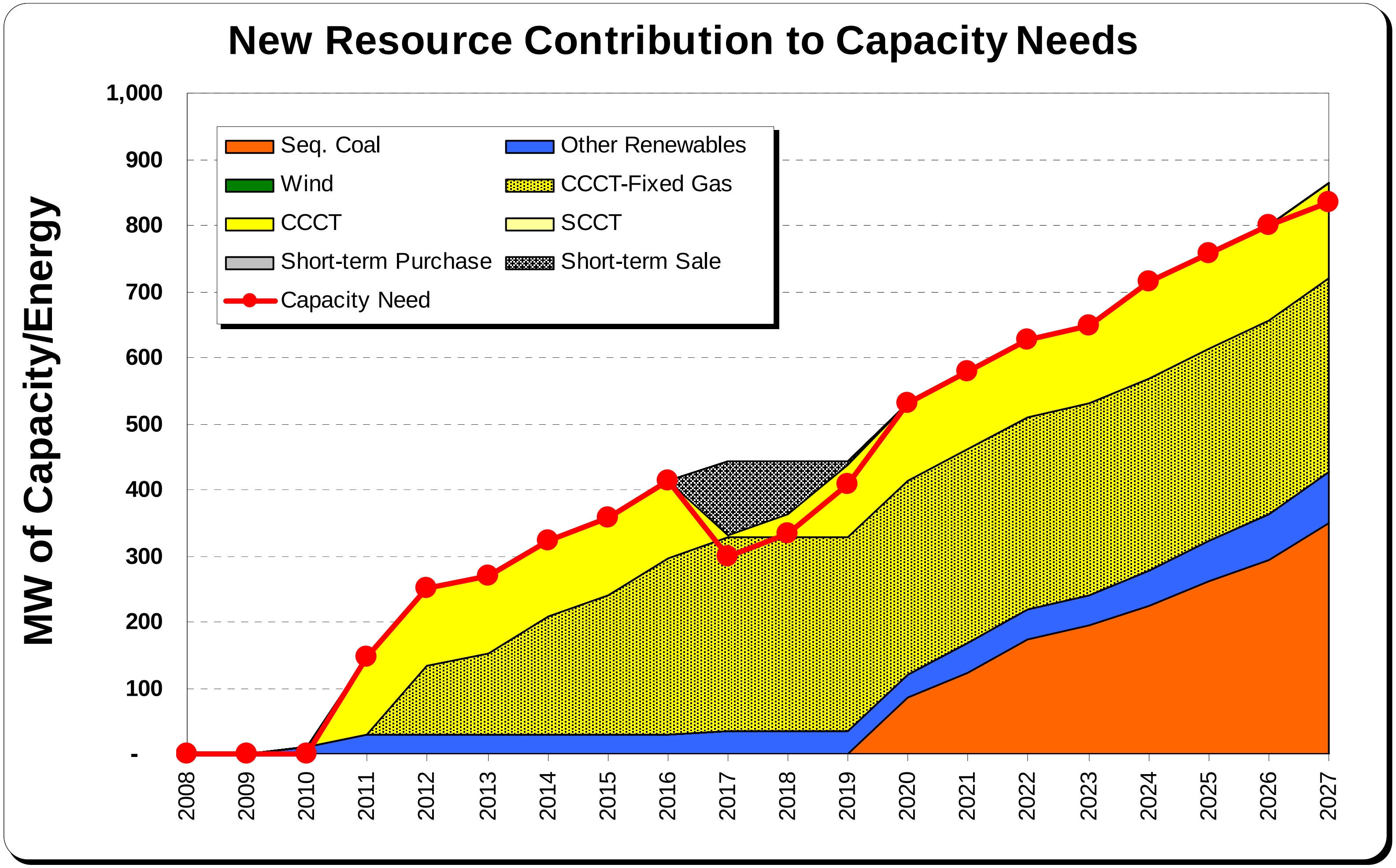
Summary Table: Base Case

#	Item	100/0	90/10	75/25	60/40	50/50	40/60	25/75	10/90	0/100
1	NPV Total Power Cost to 2017	1,656	1,692	1,814	1,859	1,859	1,862	1,862	1,862	1,909
2	NPV Total Power Cost to 2027	4,613	4,735	4,954	5,442	5,586	5,629	5,651	5,872	5,916
3	Power Cost in 2017	392	430	481	491	491	492	492	492	484
4	Power Cost in 2027	832	834	851	953	995	1,006	1,014	1,081	1,072
5	Power Cost Stdev in 2017	76	60	44	41	41	41	41	41	41
6	Power Cost Stdev in 2027	173	145	116	68	60	58	58	56	56
7	Power Cost ABSDEV in 2017	28	22	17	16	16	16	16	16	16
8	Power Cost ABSDEV in 2027	149	138	124	81	71	68	67	65	65
9	C. of V. 2016	19.3%	13.9%	9.1%	8.4%	8.4%	8.3%	8.3%	8.3%	8.5%
10	C. of V. 2027	20.8%	17.4%	13.6%	7.1%	6.0%	5.8%	5.7%	5.2%	5.2%
11	Acc. Capital Cost 2016	232	272	464	594	594	608	608	608	724
12	Acc. Capital Cost 2027	785	1,236	1,983	3,690	3,913	4,043	4,093	4,339	4,505
13	Rate AARG 2017	5.2%	5.8%	6.7%	6.9%	6.9%	6.9%	6.9%	6.9%	6.7%
14	Rate AARG 2027	4.7%	4.7%	4.8%	5.3%	5.4%	5.5%	5.5%	5.8%	5.8%
15	Rate Max Year	9.3%	9.6%	9.5%	9.5%	9.5%	9.9%	9.8%	11.9%	12.6%
16	2017 95th% Diff	144.9	116.6	81.5	72.9	72.9	72.5	72.5	72.5	72.5
17	DSM Reduction to Capacity by 2017									
18	Coal Capacity by 2017	-	-	-	-	-	-	-	-	-
19	CCCT Capacity by 2017	-	16	117	117	117	106	106	106	106
20	CT Capacity by 2017	394	233	-	-	-	-	-	-	-
21	Wind Nameplate by 2017	-	100	300	400	400	400	400	400	400
22	Oil Sands Capacity by 2017	-	-	-	-	-	-	-	-	-
23	OtherRenew Capacity by 2017	20	34	34	34	34	34	34	34	34
24	Other Resources Capacity by 2017	-	160	292	292	292	303	303	303	303
25	DSM Reduction to Capacity by 2027									
26	Coal Capacity by 2027	-	-	-	238	349	377	377	186	171
27	CCCT Capacity by 2027	-	16	249	226	145	106	106	106	106
28	CT Capacity by 2027	815	600	215	-	-	-	-	-	-
29	Wind Nameplate by 2027	-	100	300	600	600	600	600	600	600
30	Oil Sands Capacity by 2027	-	-	-	-	-	-	-	211	226
31	OtherRenew Capacity by 2027	20	59	78	78	78	78	78	59	59
32	Other Resources Capacity by 2027	-	160	292	292	292	303	303	303	303

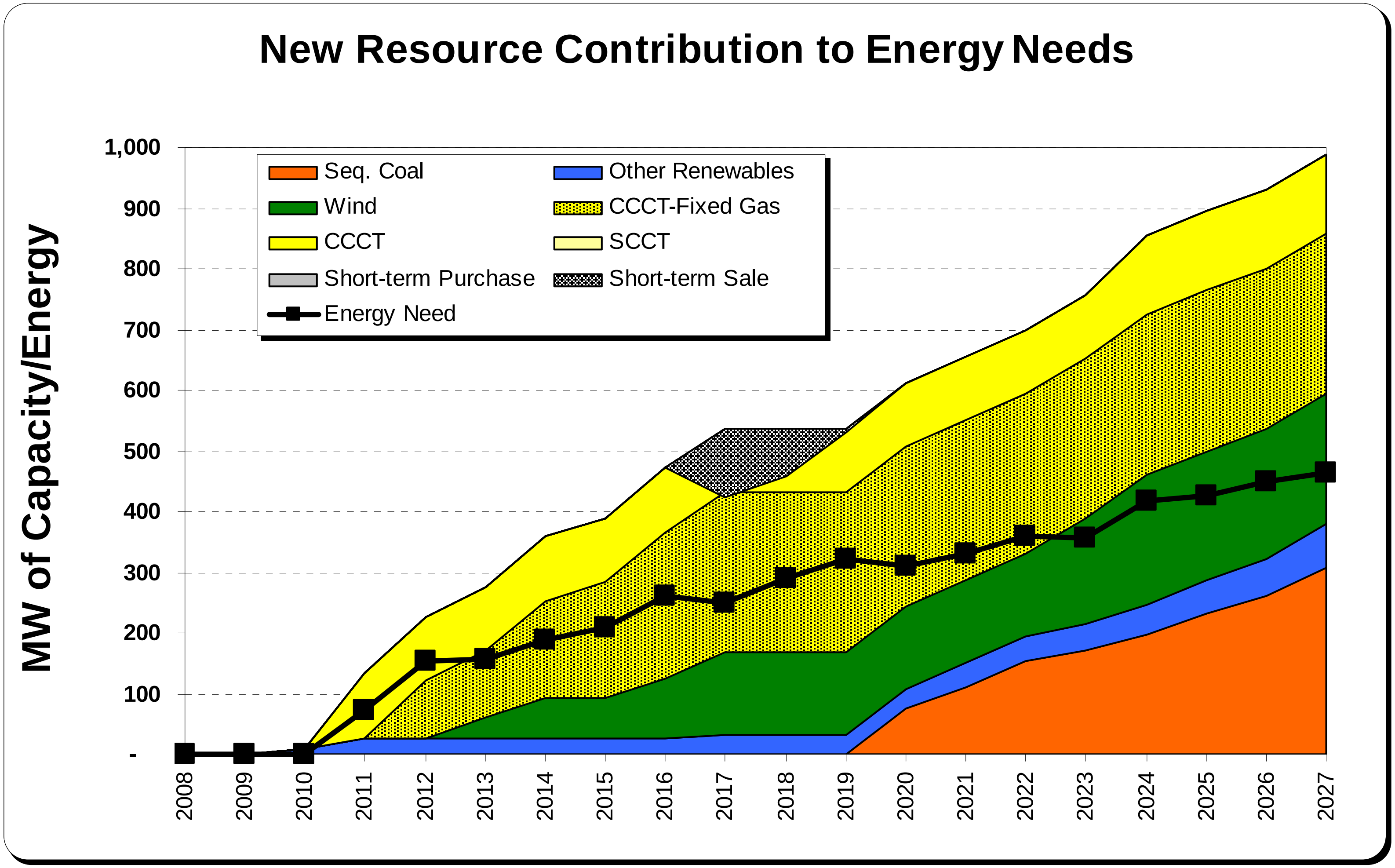
Power Supply Risk Comparison



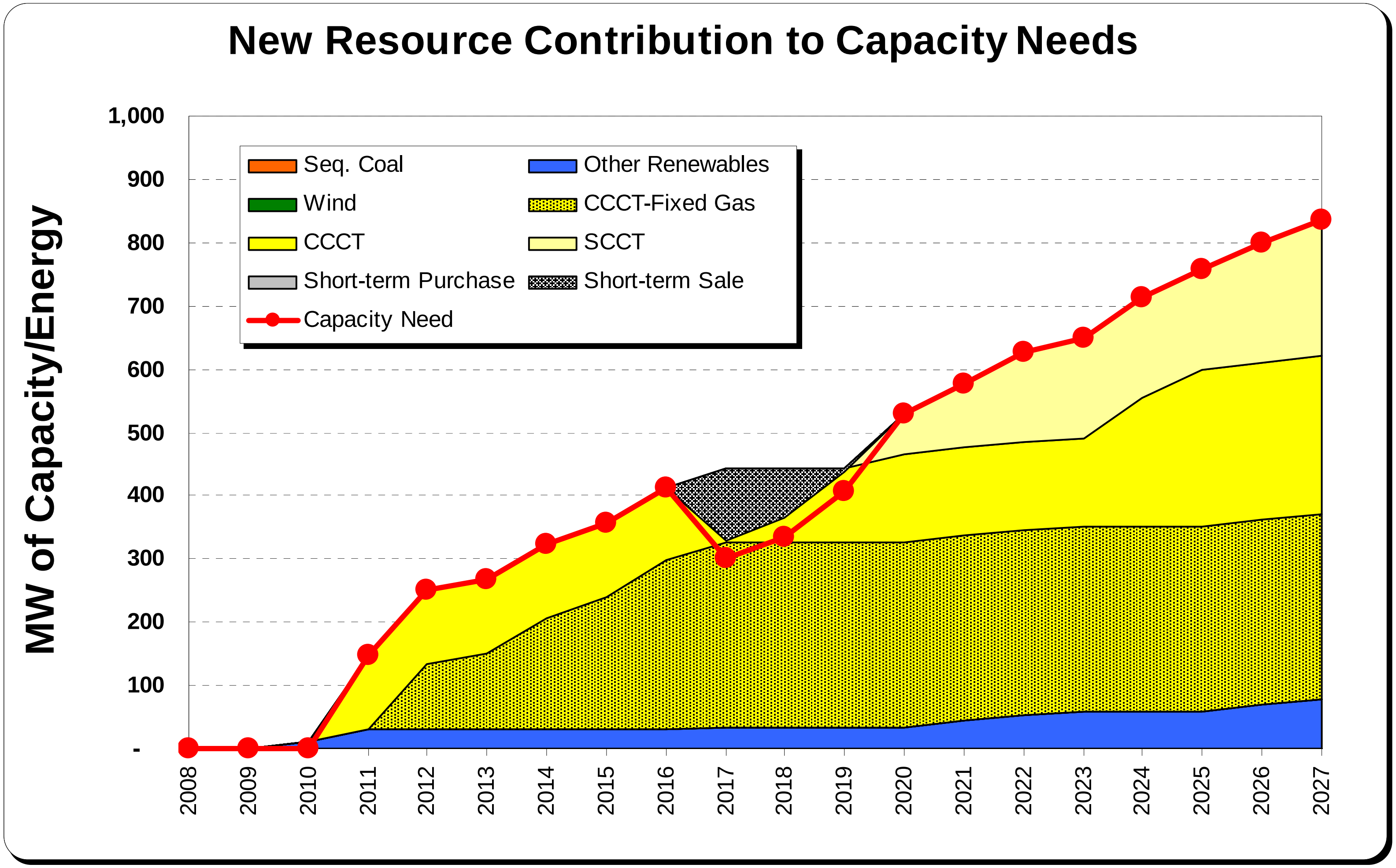
Resource Mix (50/50) Capacity



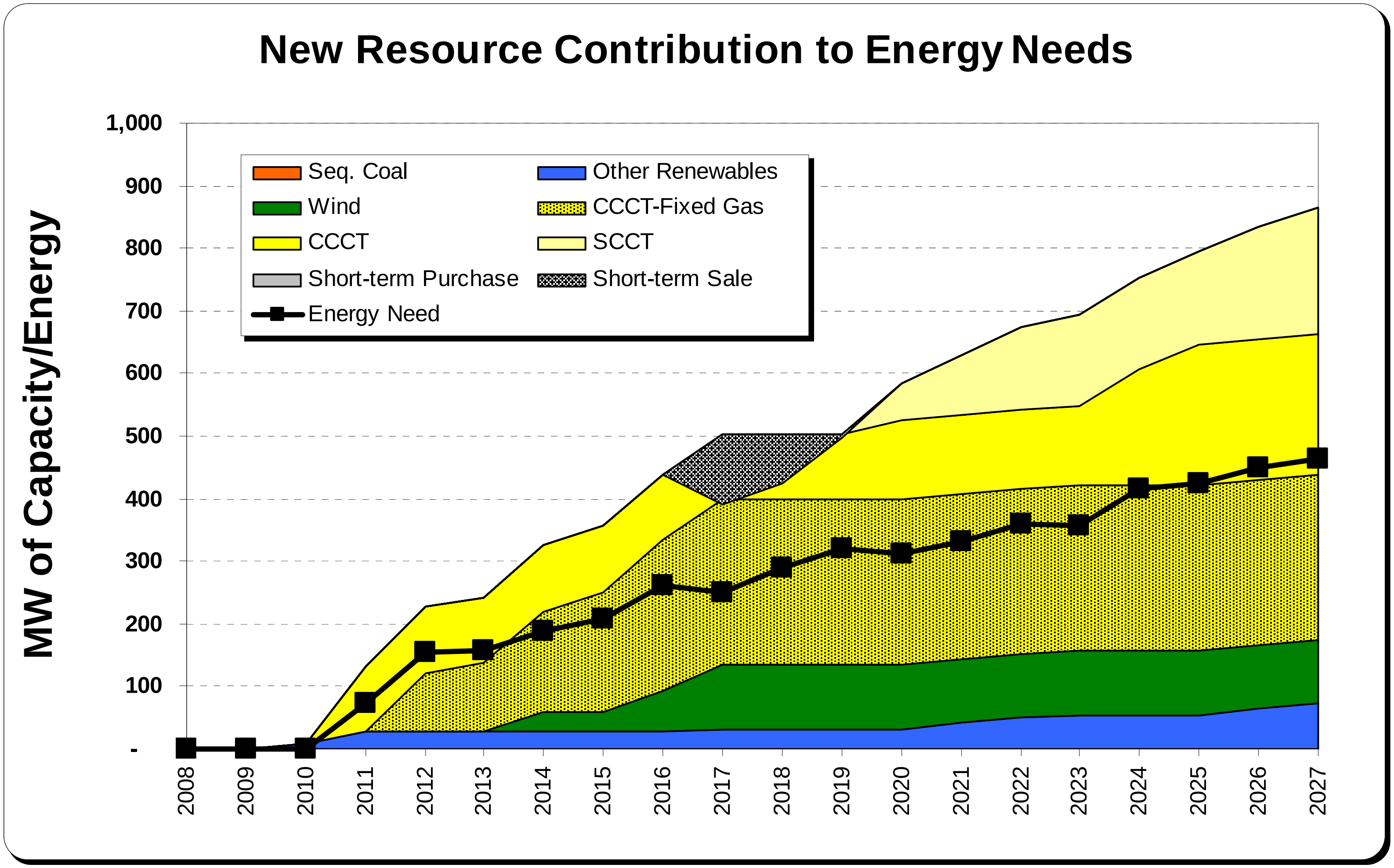
Resource Mix (50/50) Energy



Resource Mix (75/25) Capacity



Resource Mix (75/25) Energy



Next Steps

- Finalize Preferred Resource Strategy and add “lumpiness”
- Conduct additional portfolio analysis
- Test Preferred Resource Strategy against all futures & scenarios

Cost of Service

2007 Electric Integrated Resource Plan
Fourth Technical Advisory Committee Meeting
March 28, 2007

Tara Knox

Cost of Service Background

Cost of Service Process (See handout)

- Purpose is to determine the share of total cost each customer group should pay based on usage characteristics

Production and Transmission Costs are classified as energy-related and demand-related components

- Energy is total annual consumption
- Demand is simultaneous consumption (peak)

Over the past 20 years, Washington has used “peak credit” to classify Production and Transmission Costs, Avista has also used “peak credit” in Idaho over the same period

Avista's Current Cost of Service Calculation

- Replacement Cost Comparison (See handout)
- All Avista resources represented
- Thermal segregated from Hydro, with their own peak credit factors
  - CS2 as intermediate plant included with thermal base load
  - Brings down the average thermal cost which raises the demand proportion
- Transmission ratio is 50/50 weighting of thermal and hydro ratios

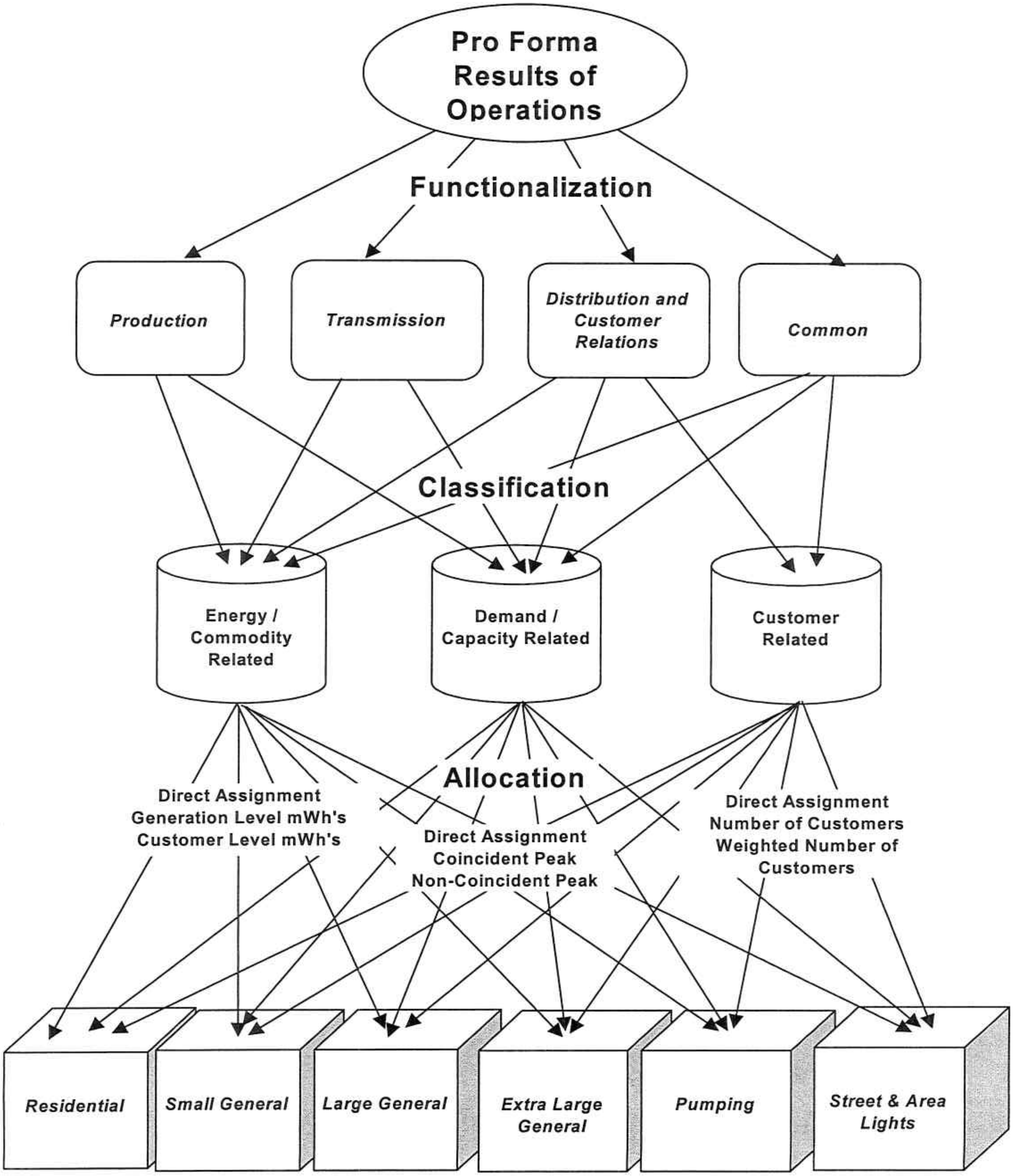
Puget Sound Energy – Cost of Service

- PSE uses a levelized cost comparison
  - Compares hypothetical CT with a hypothetical CCCT
  - Peaking unit hours of operation and fuel choices are derived from the Puget IRP

Cost of Service Questions

- Can we incorporate IRP information into Avista’s Demand/Energy classification?
- From an operating prospective, what is the appropriate cost split between demand and energy?
- Looking for suggestions

ELECTRIC COST OF SERVICE STUDY FLOWCHART



Pro Forma Results of Operations by Customer Group

Peak Credit Demand/Energy Allocator Calculation

	Replacement Cost "$" (1)	Installed Capacity KW (2)	Cost per KW $	%	Classification
Thermal and Coyote Springs					
Kettle Falls (212)	169,066,749	50,700	$3,335		
Colstrip (410)	292,403,948				
Colstrip (411)	211,270,898				
Total Colstrip	503,674,846	233,400	$2,158		
Coyote Springs II (610)	162,320,975	287,000	$566		
Total Thermal	835,062,570	571,100	$1,462		
Peaking Units					
Kettle Falls CT (211)	9,164,018	7,200	$1,273		
Norteast Spokane CT (213)	27,081,245	61,800	$438		
Boulder Park CT (216)	31,567,782	24,600	$1,283		
Rathdrum CT (310)	59,872,834	166,500	$360		
Total Peaking Units	127,685,880	260,100	$491		
Hydro Plant					
Monroe Street (201)	46,947,839	14,800	$3,172		
Little Falls (202)	104,086,383	32,000	$3,253		
Long Lake (203)	271,004,114	70,000	$3,871		
Upper Falls (204)	58,288,767	10,000	$5,829		
Nine Mile (205)	82,084,830	26,400	$3,109		
Post Falls (300)	79,262,577	14,800	$5,356		
Cabinet Gorge (304)	433,446,950	265,000	$1,636		
Noxon Rapids (401)	584,184,717	473,400	$1,234		
Total Hydro	1,659,306,177	906,400	$1,831		
Thermal Plant Average Replacement Cost per KW Capacity			$1,462	100.00%	
Less:					
Peaking Units Average Replacement Cost per KW Capacity			$491	33.57%	Demand
Remainder			$971	66.43%	Energy
Thermal Peak Credit					
Hydro Plant Average Replacement Cost per KW Capacity			$1,831	100.00%	
Less:					
Peaking Units Average Replacement Cost per KW Capacity			$491	26.82%	Demand
Remainder			$1,340	73.18%	Energy
Hydro Peak Credit					
Transmission					
50/50 Weighting Thermal and Hydro Demand Percentages				30.19%	Demand
50/50 Weighting Thermal and Hydro Energy Percentages				69.81%	Energy
Transmission Peak Credit				100.00%	Total

(1) From Replacement Cost Column on the Plant Report Titled "Insurance Report - FA Cost 2004 2005 - FINAL with Subtotals" for the Year Ended 12-31-2005.

(2) From 2005/Q4 FERC Form 1, Pages 402, 403, 406, 407, and 410, line 5 for each plant.

Estimated Resource Integration Costs

Randy Gnaedinger

System Planning Engineer

Topics

Study Work Performed

Avista's Transmission System vs. Other Utilities System

Regional Concerns

Resource Integration Report

Study Work Outline

- Generation Size
  - 50 to 400+ MW
  - At 23 total different locations
- Indifferent of Fuel Type
  - Wind vs. Natural Gas
- Timeframe – 2015
- Powerflow
  - 3 seasons

Outside vs. Inside Avista's Transmission System

- Knowledge of One's Own System
- Future Projects
- Special Circumstances
  - Western Montana Hydro Agreement

Regional Concerns

Transmission Paths

- West of Hatwai
- Idaho to Northwest
- Montana to Northwest

Regional Process and Other Utility Assessment

2007 IRP Integration Report

2015 Timeframe

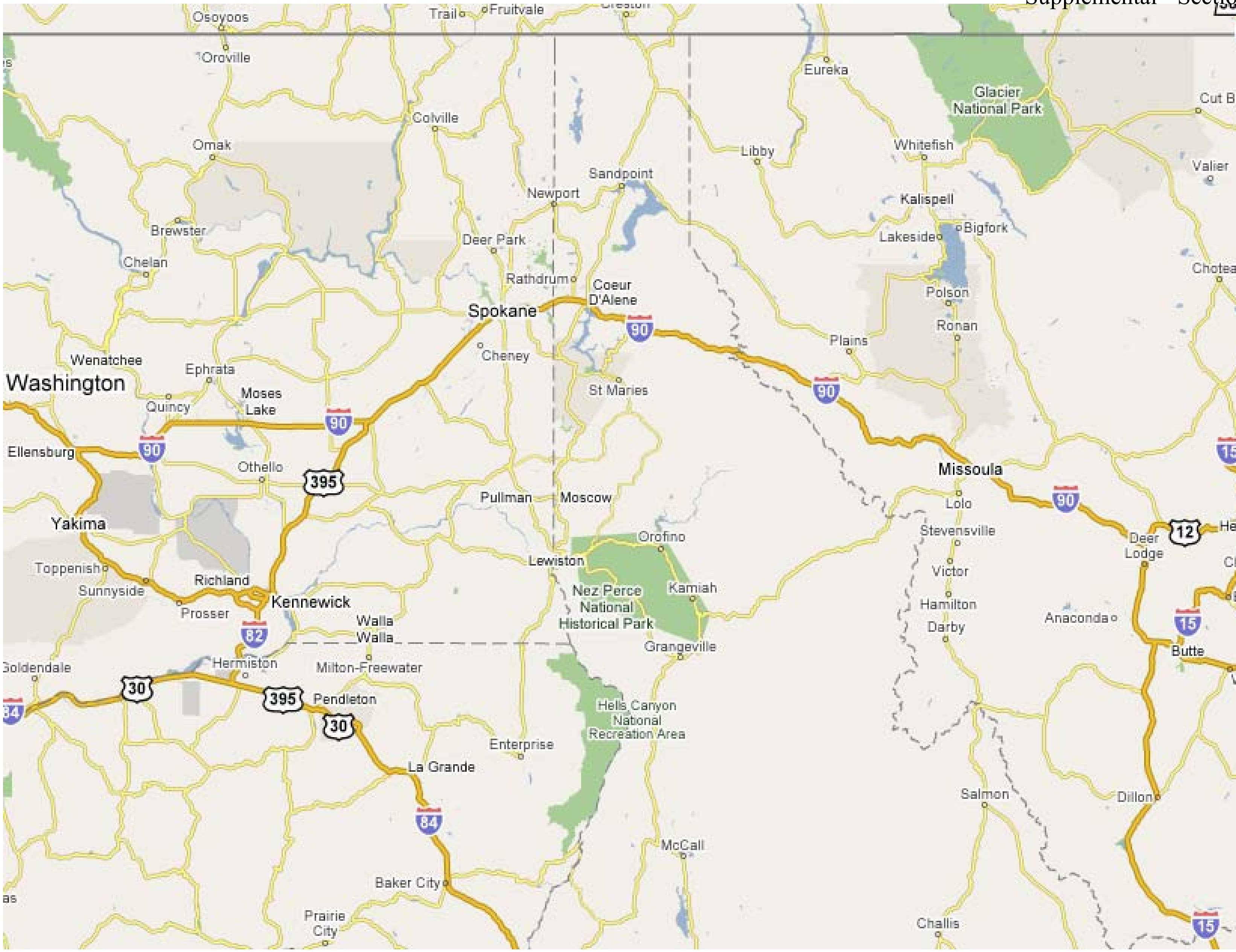
Smaller Project Integration

Larger Project Integration

Cost Estimates

Estimated Integration Costs Inside Avista's System

MW Size / Location	50 MW	100 MW	250 MW	400+ MW
Sprague, WA	NA	NA	$58M	$80+M
Spokane/ Coeur d'Alene	$3M	$7M	$32M	$32M-$500M
Mica Peak	$4M	NA	NA	NA
Clark Fork Hydro	$0	NA	NA	NA
Dayton, WA	$32M	$32M	NA	NA
Reardan, WA	$2M	$13M	NA	NA
Lind, WA	$1.5M	$6M	NA	NA
Othello, WA	$1.5M	NA	NA	NA
Colfax, WA	$1.5M	NA	NA	NA


Osoyoos
Trail
Fruitvale
Oroville
Eureka
Glacier National Park
Colville
Omak
Libby
Whitefish
Valier
Sandpoint
Newport
Kalispell
Brewster
Lakeside
Bigfork
Deer Park
Chelan
Choteau
Rathdrum
Coeur D'Alene
Polson
Spokane
90
Ronan
Plains
Cheney
Wenatchee
Ephrata
Washington
St Maries
90
Moses Lake
Quincy
90
15
Ellensburg
90
Missoula
Othello
395
Lolo
90
Pullman
Moscow
Yakima
Stevensville
Orofino
12
Deer Lodge
Lewiston
Toppenish
Victor
Richland
Nez Perce National Historical Park
Kamiah
Sunnyside
Kennewick
Hamilton
Prosser
Walla Walla
Anaconda
Darby
82
15
Grangeville
Butte
Hermiston
Milton-Freewater
30
395
Pendleton
Hells Canyon National Recreation Area
30
Enterprise
La Grande
Salmon
Dillon
84
McCall
Baker City
Prairie City
Challis
15

Questions?

2007 IRP Estimated Resource Integration Costs Document is posted on Avista's OASIS

Avista Utilities 2007 Integrated Resource Plan

Technical Advisory Committee Meeting No. 5 Agenda

Wednesday April 25, 2007

	Topic	Time	Staff
1.	Introductions	9:30	Barcus
2.	Review of 4th TAC Meeting	9:40	Lyons
3.	Presentation of PRS for 2007 IRP	9:45	Kalich/Gall
4.	Lunch	12:00	
5.	PRS continued	12:45	Kalich/Gall
6.	Action Items	3:00	Lyons
7.	Adjourn	3:30	

Review of the Fourth Technical Advisory Committee Meeting

2007 Electric Integrated Resource Plan

Fifth Technical Advisory Committee Meeting

April 25, 2007

John Lyons

Fourth Technical Advisory Committee Meeting

- Market Analysis
- Load Forecast Scenario on Global Warming
- Conservation Program Update
- DSM at Avista Facilities
- Portfolio Selection Criteria
- Cost of Service
- Transmission Cost Estimates for the 2007 IRP

Preferred Resource Strategy Analysis

2007 Electric Integrated Resource Plan

Fifth Technical Advisory Committee Meeting

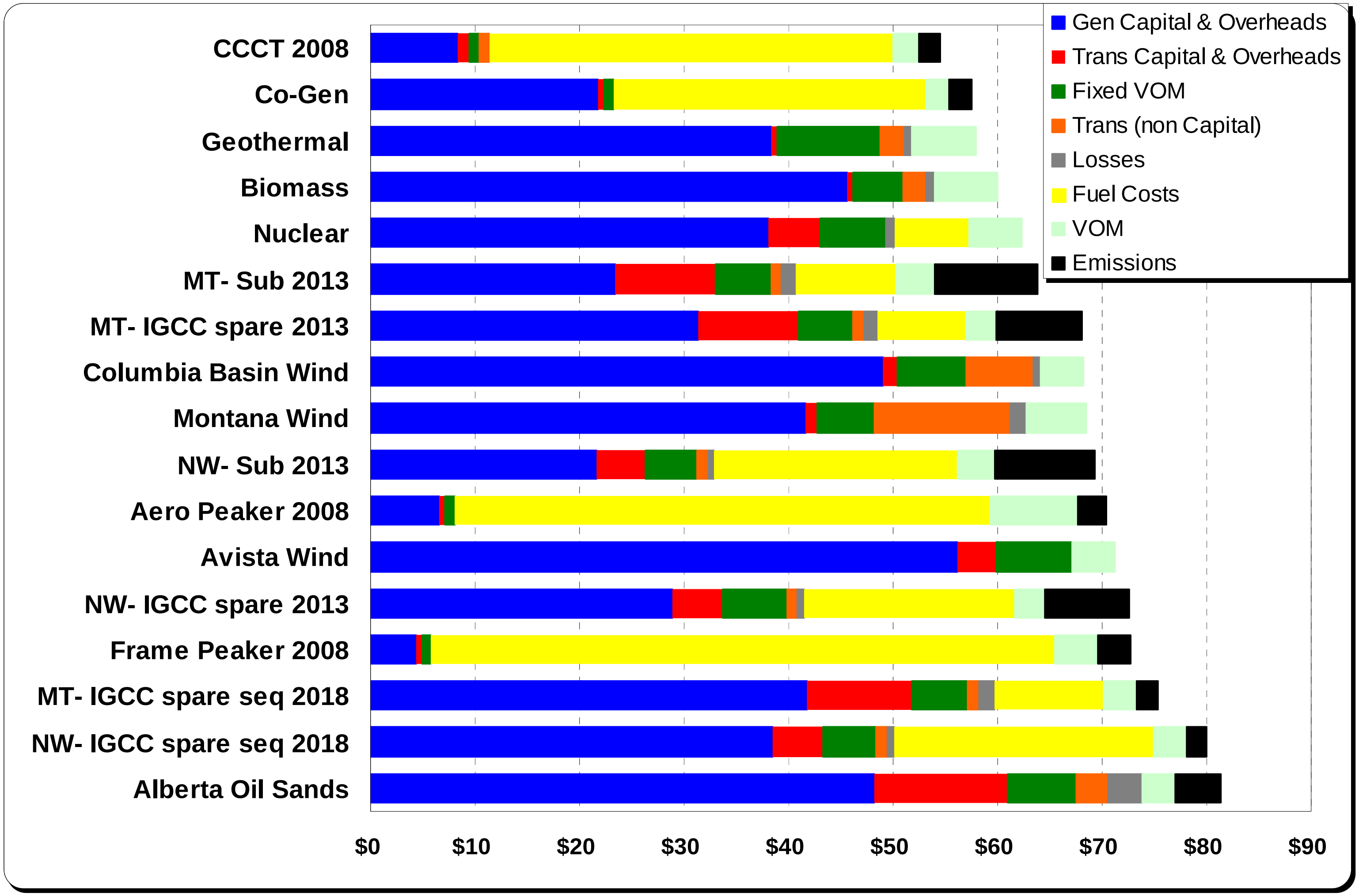
April 25, 2007

Clint Kalich

James Gall

Short List Resource Options

(Levelized $2007 "real"/MWh)



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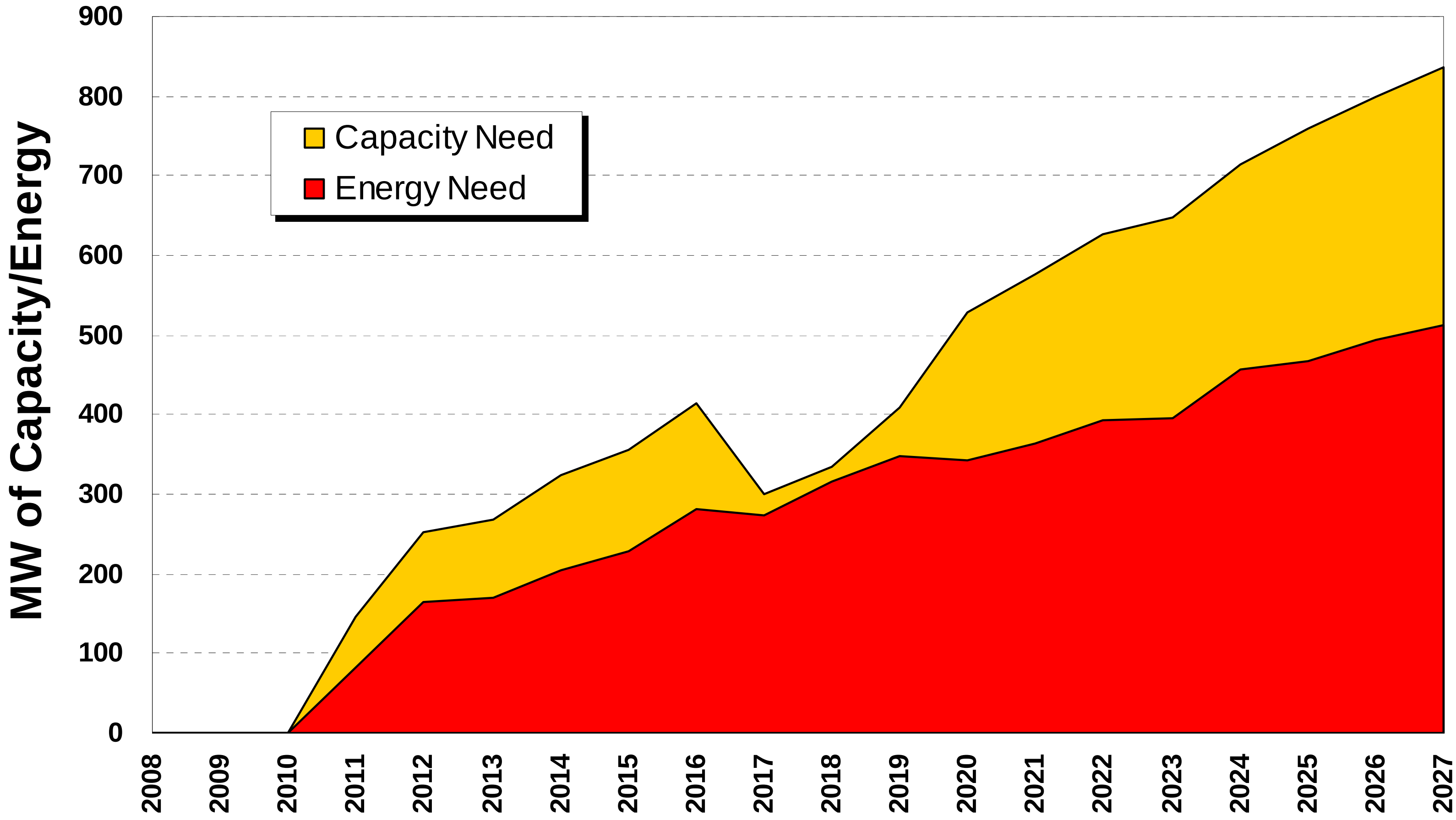
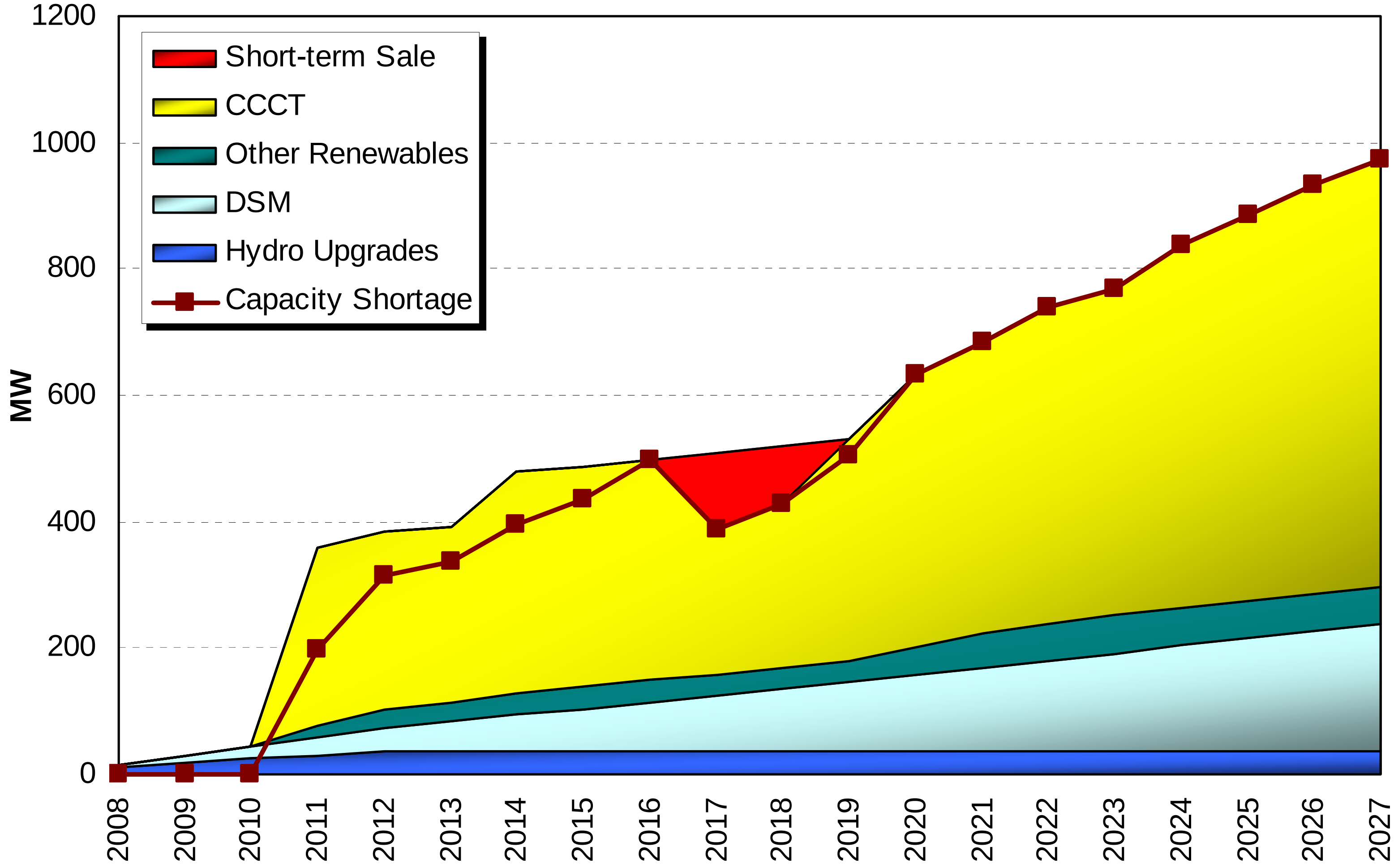
Oil Sands	3,963		IGCC – Sequestered	3,045
Nuclear	3,100		IGCC - Sequestered w/Spare Gasifier	3,232
Small Co-Gen	2,100			

Company cannot construct options highlighted in red

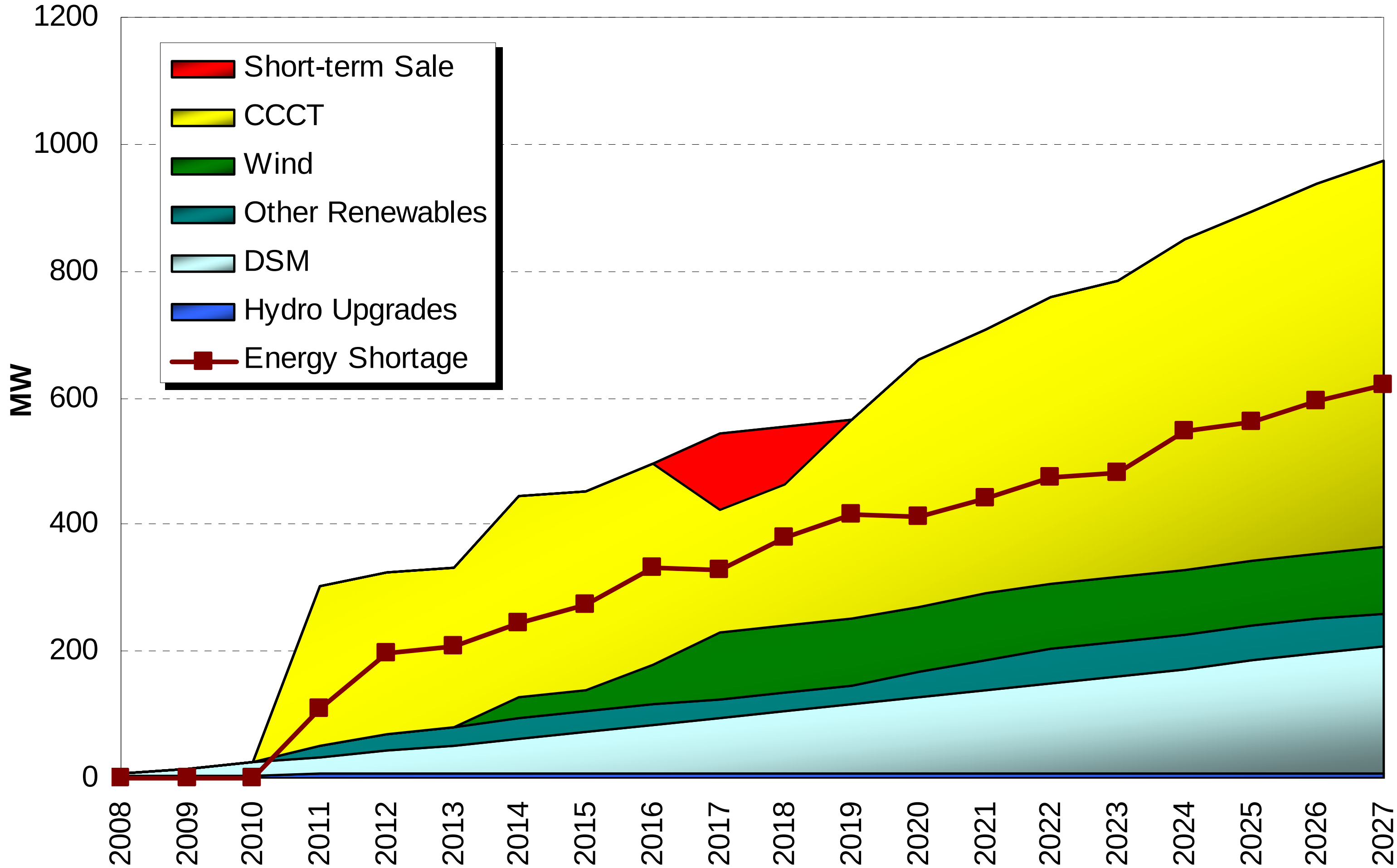
Avista's Annual Average Resource Need



Preferred Resource Strategy- Capacity

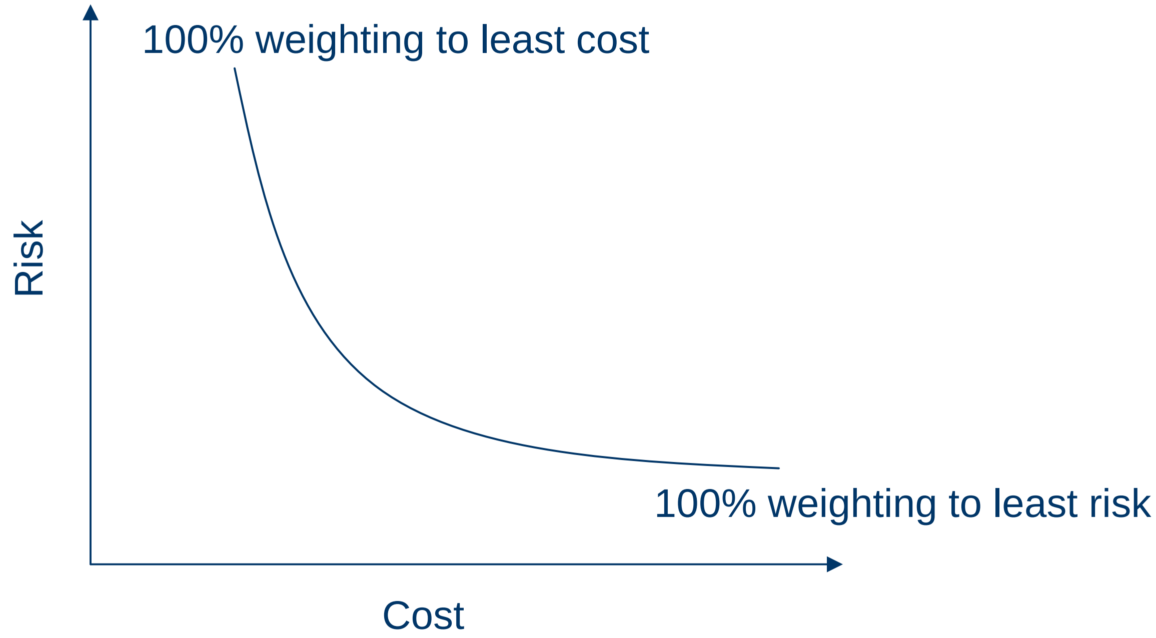


Preferred Resource Strategy- Energy

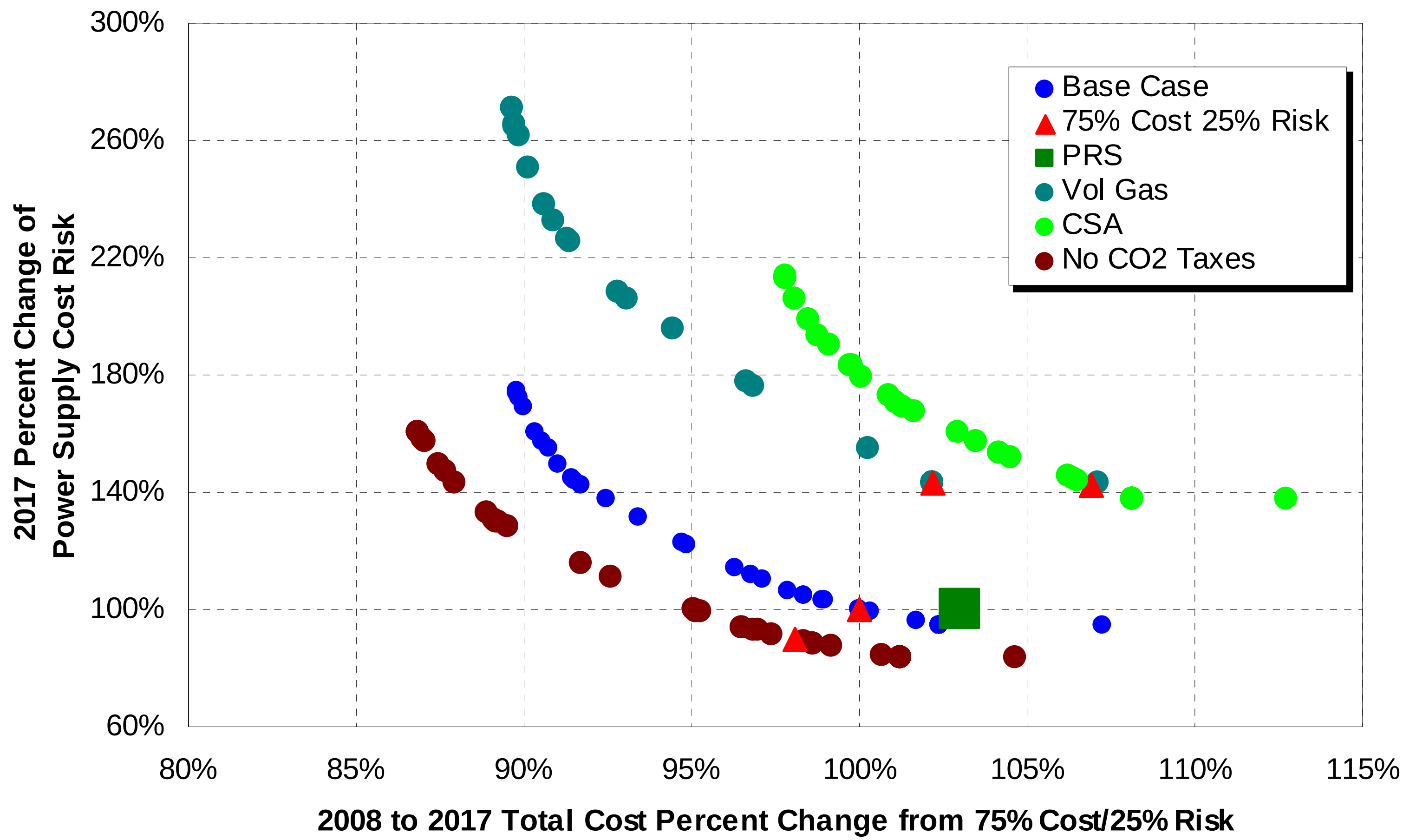


What is the Efficient Frontier?

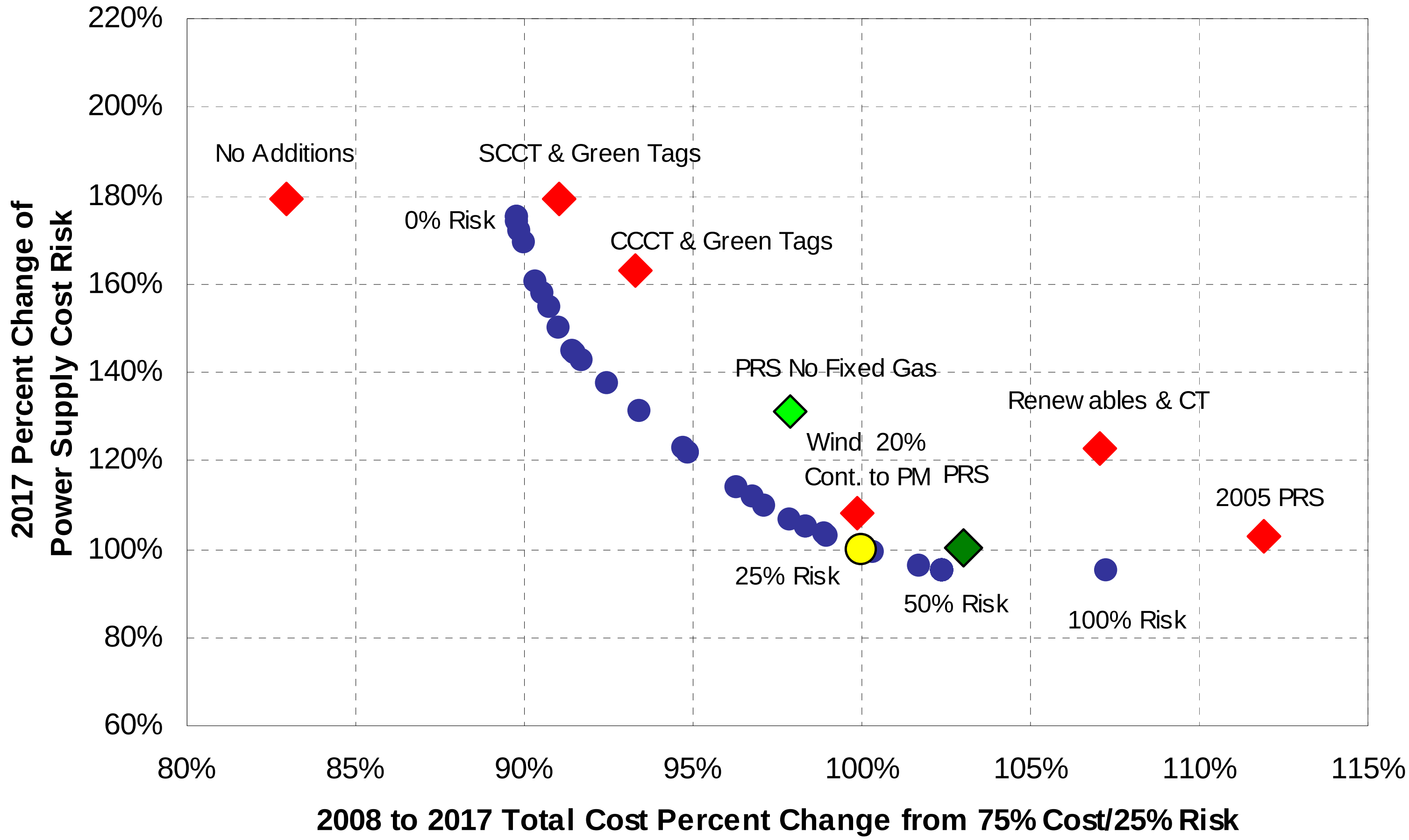
- Demonstrates the trade off of cost and risk
- Difficulty: how much additional cost are we willing to pay to reduce risk



Efficient Frontiers

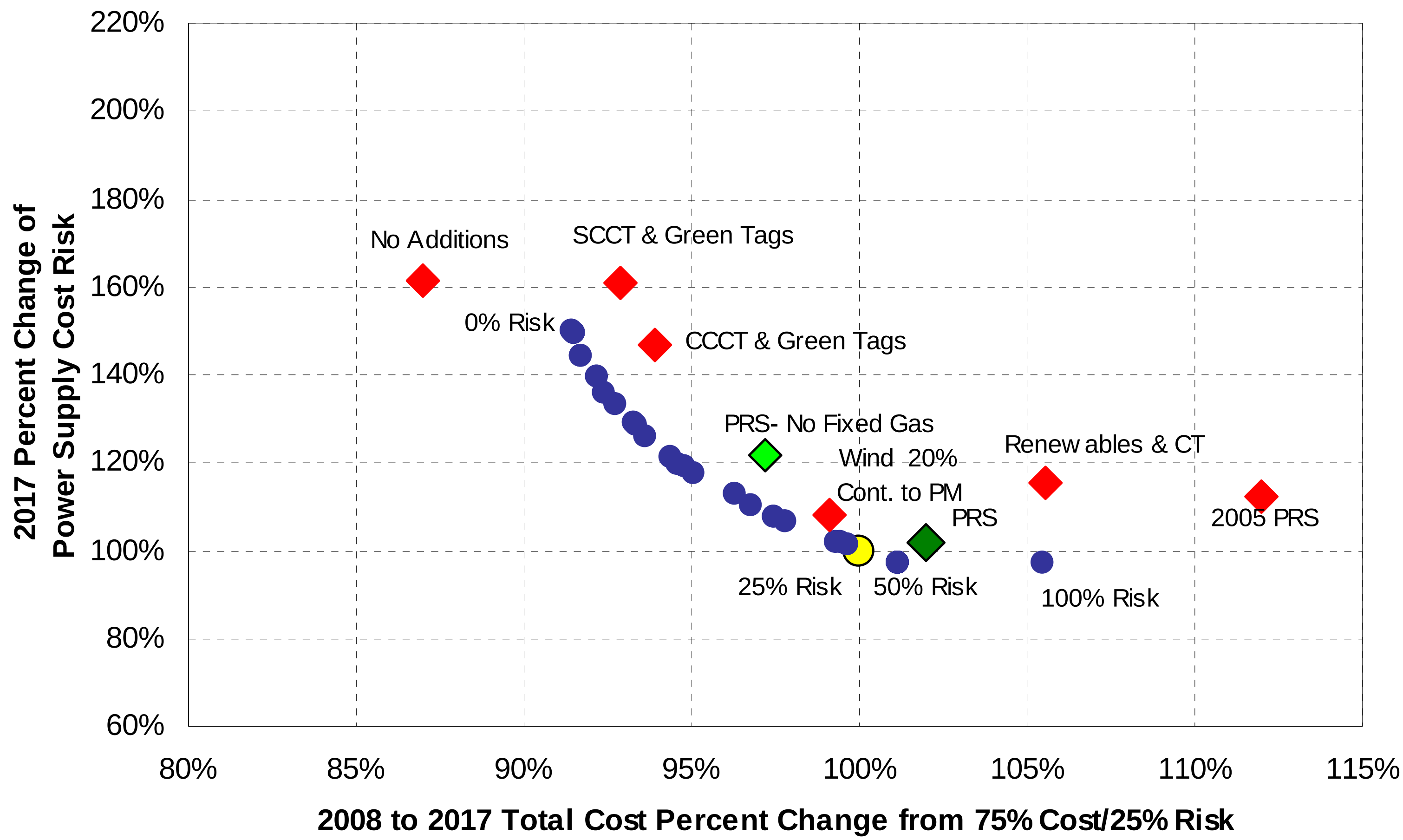


Efficient Frontier- Base Case

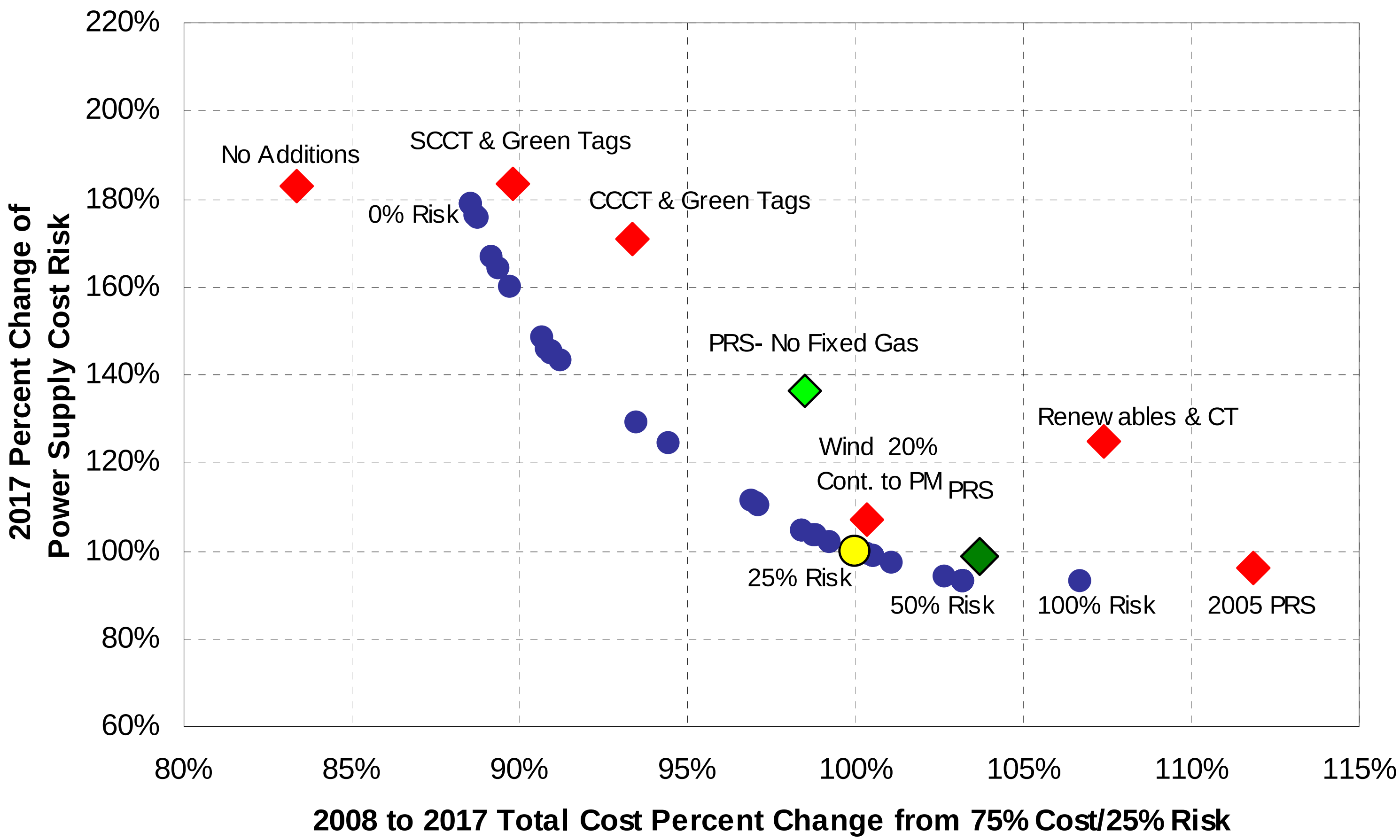


No RPS and Corporate RPS to be included in final document

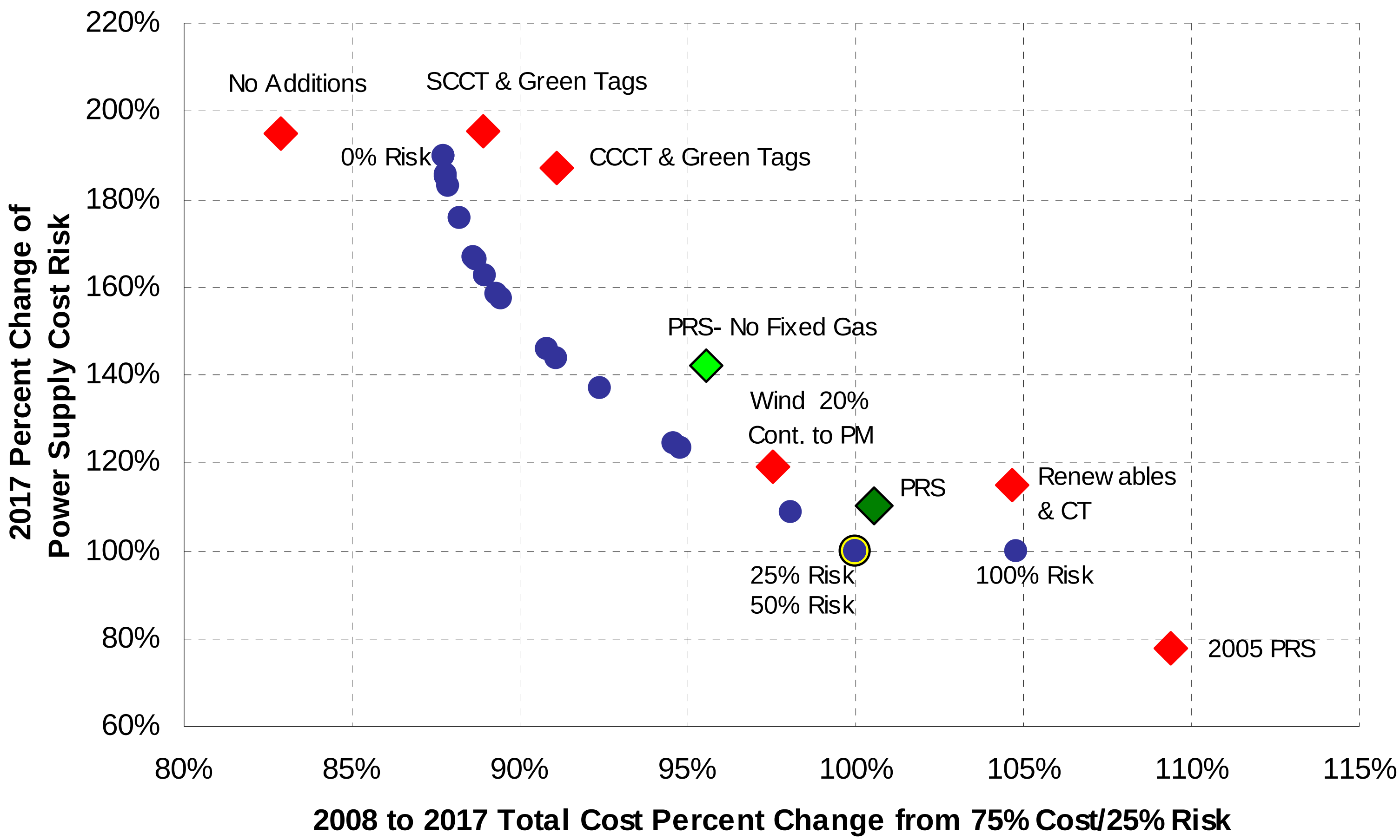
Efficient Frontier- C.S.A. Future



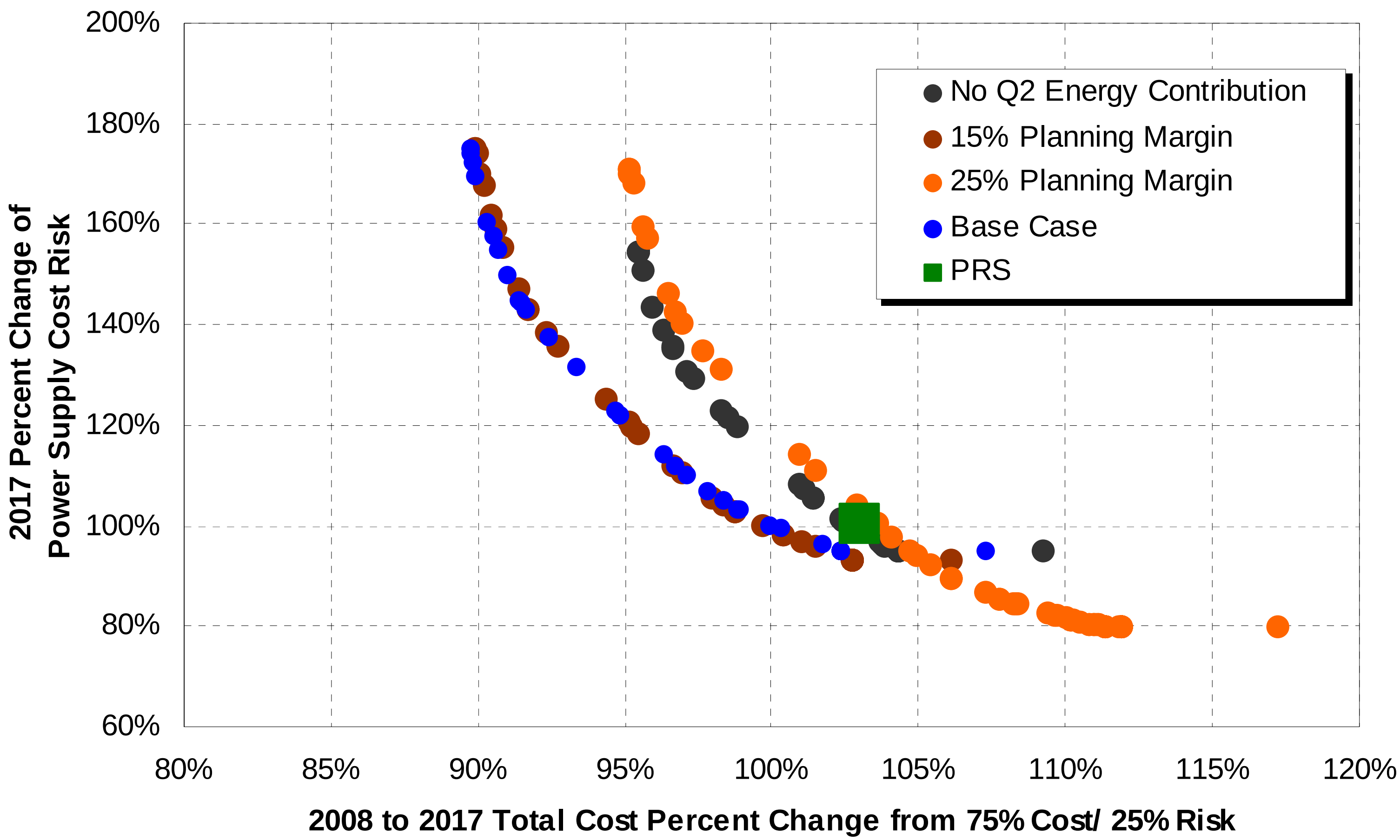
Efficient Frontier- Carbon “Okay” Future



Efficient Frontier- Volatile Natural Gas Price Future

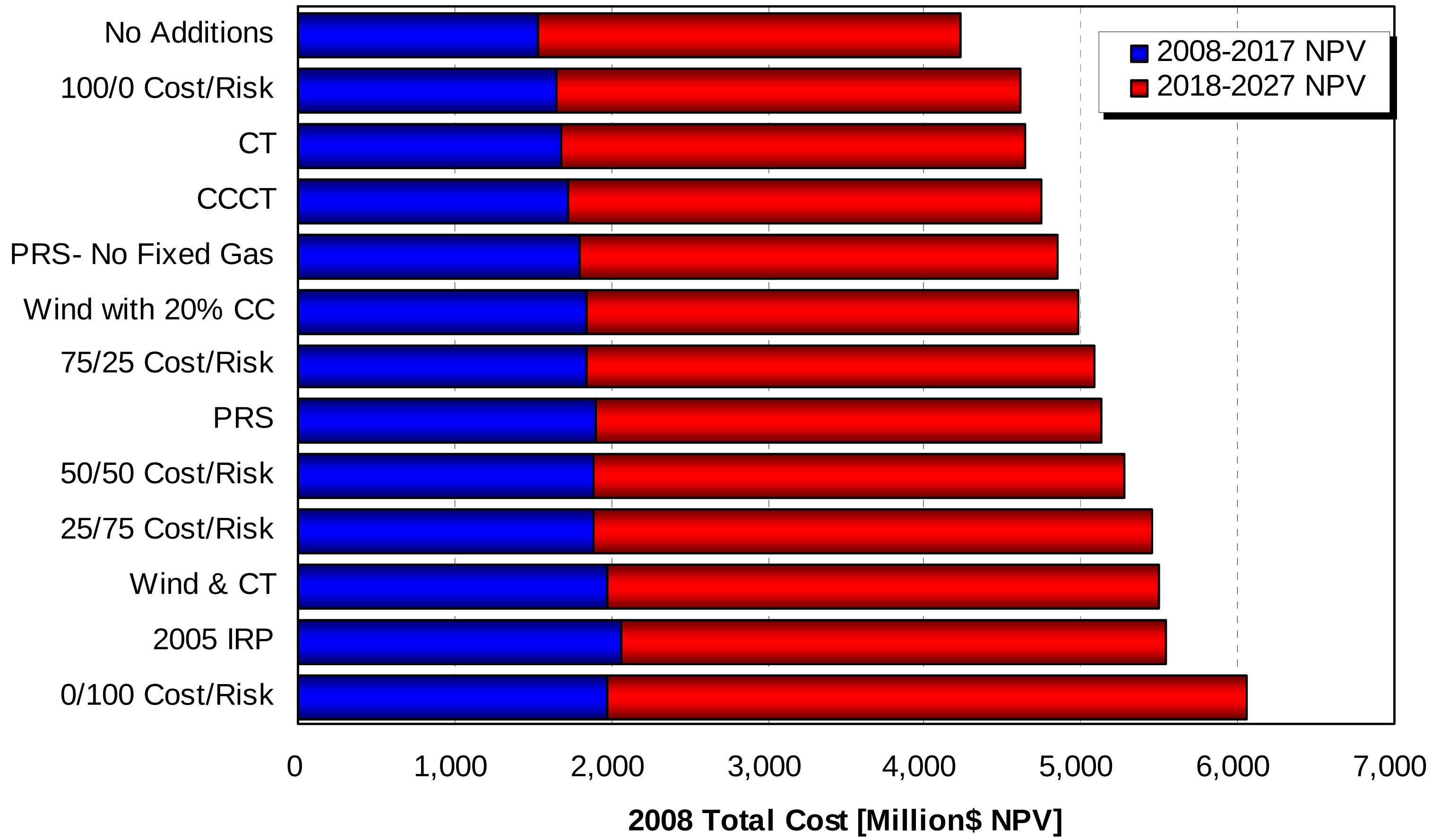


Efficient Frontier- Alternative Planning Criteria



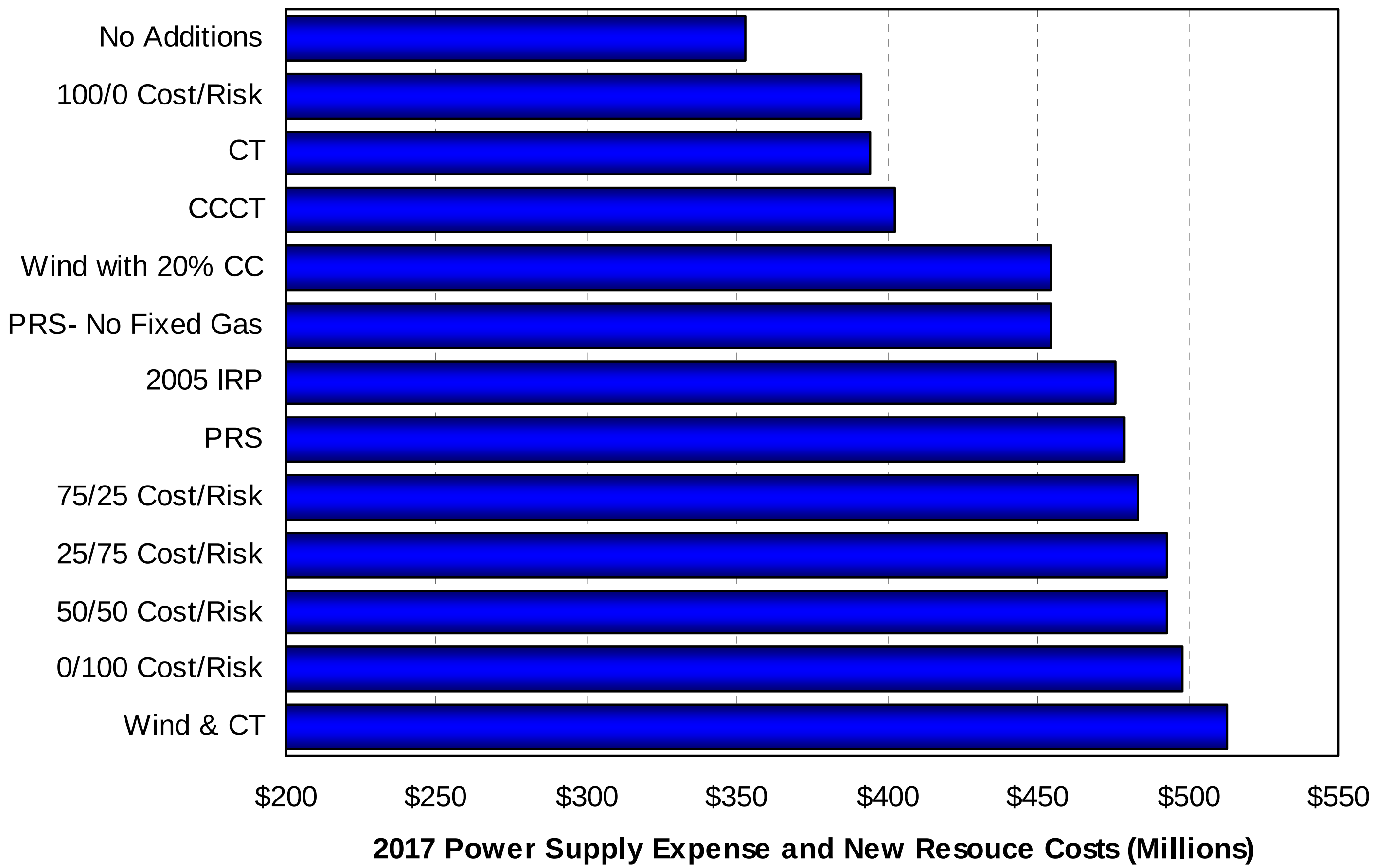
Portfolio Comparison- Total Cost

Power Supply Expense and New Resource Costs



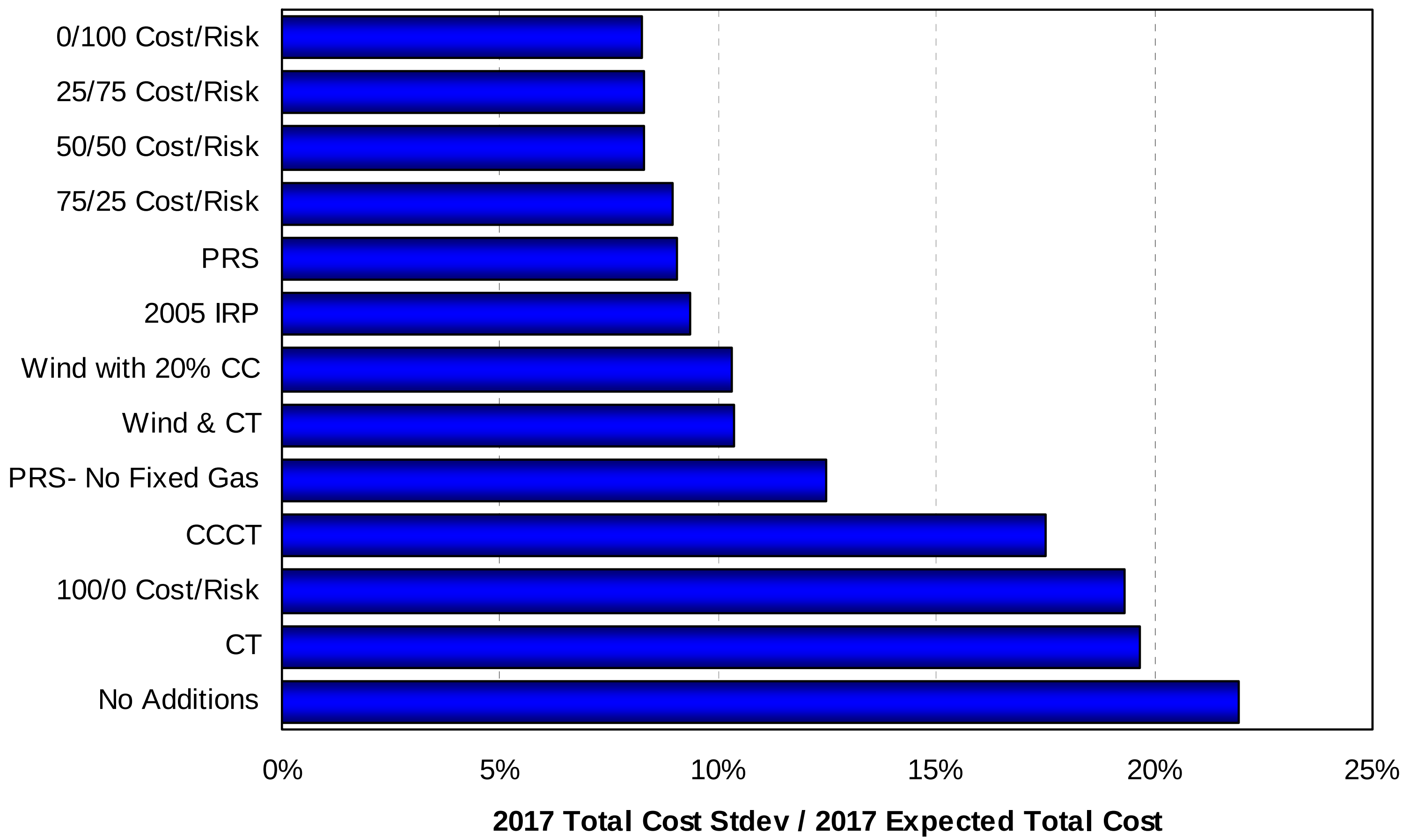
Portfolio Comparison- 2017 Total Cost

Total of existing portfolio and new resources



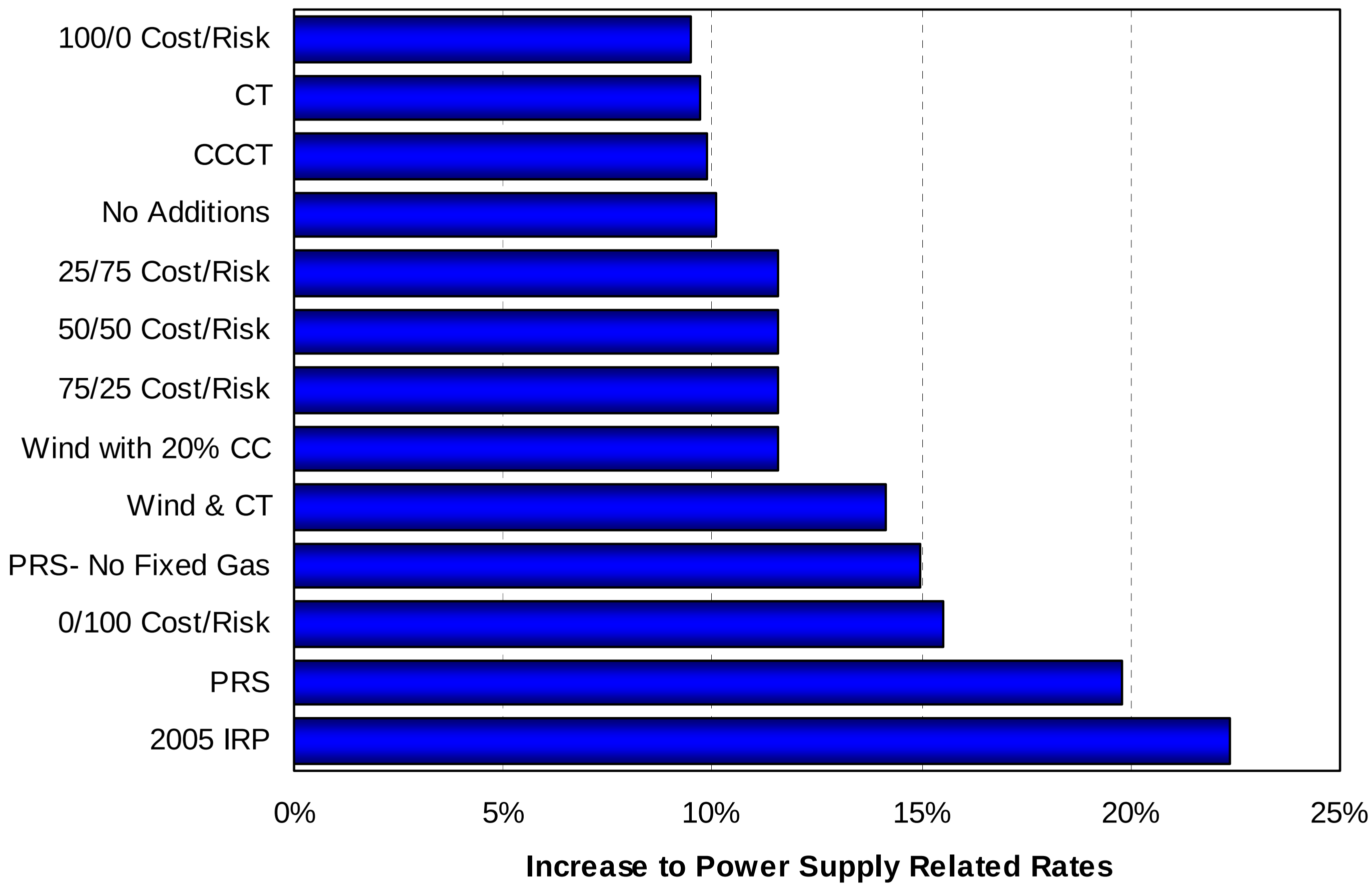
Portfolio Comparison- 2017 Risk

Coefficient of variation (standard deviation divided by total expected cost)



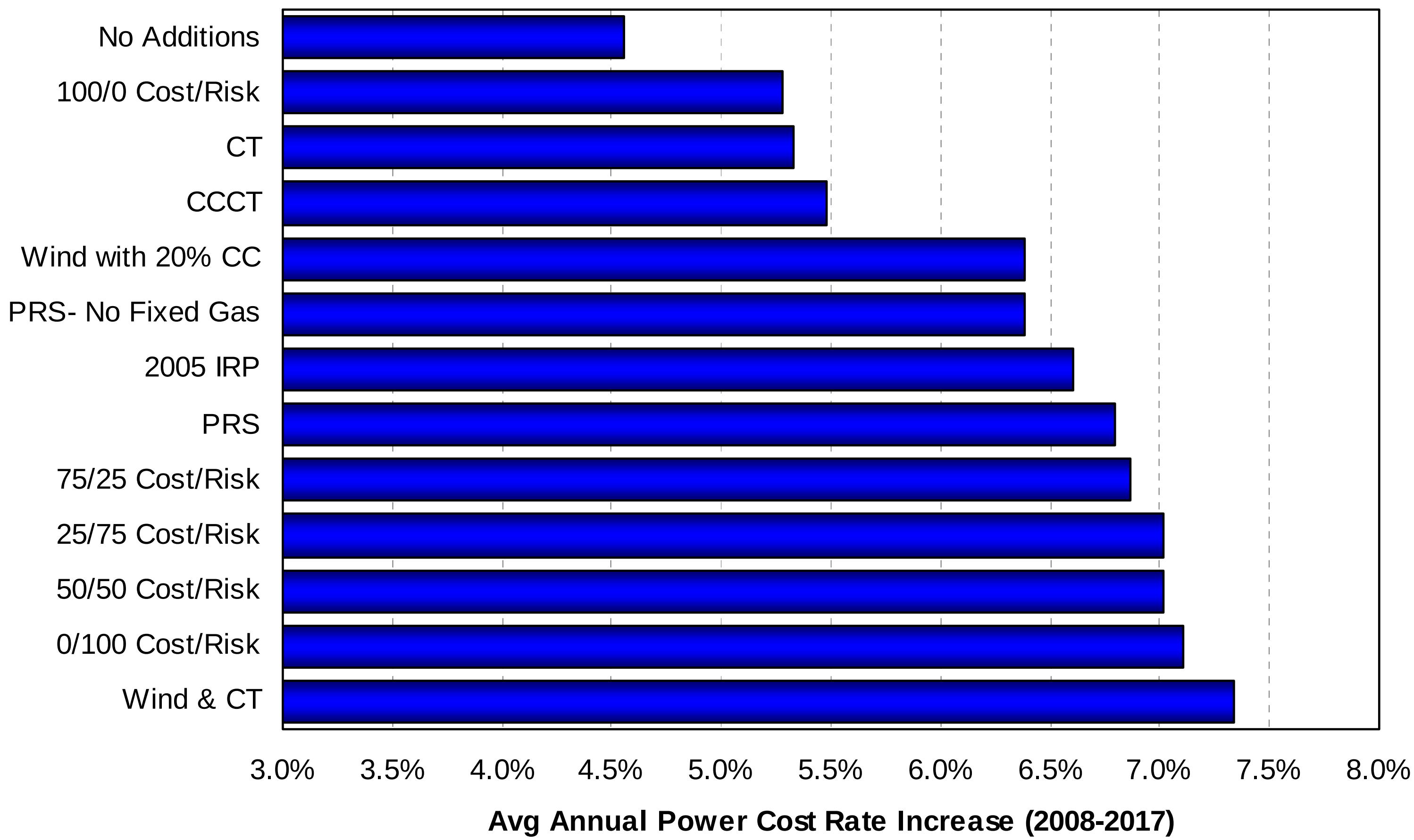
Portfolio Comparison- Max Annual Increase

Power supply-related costs ONLY (2008-2018 timeframe)



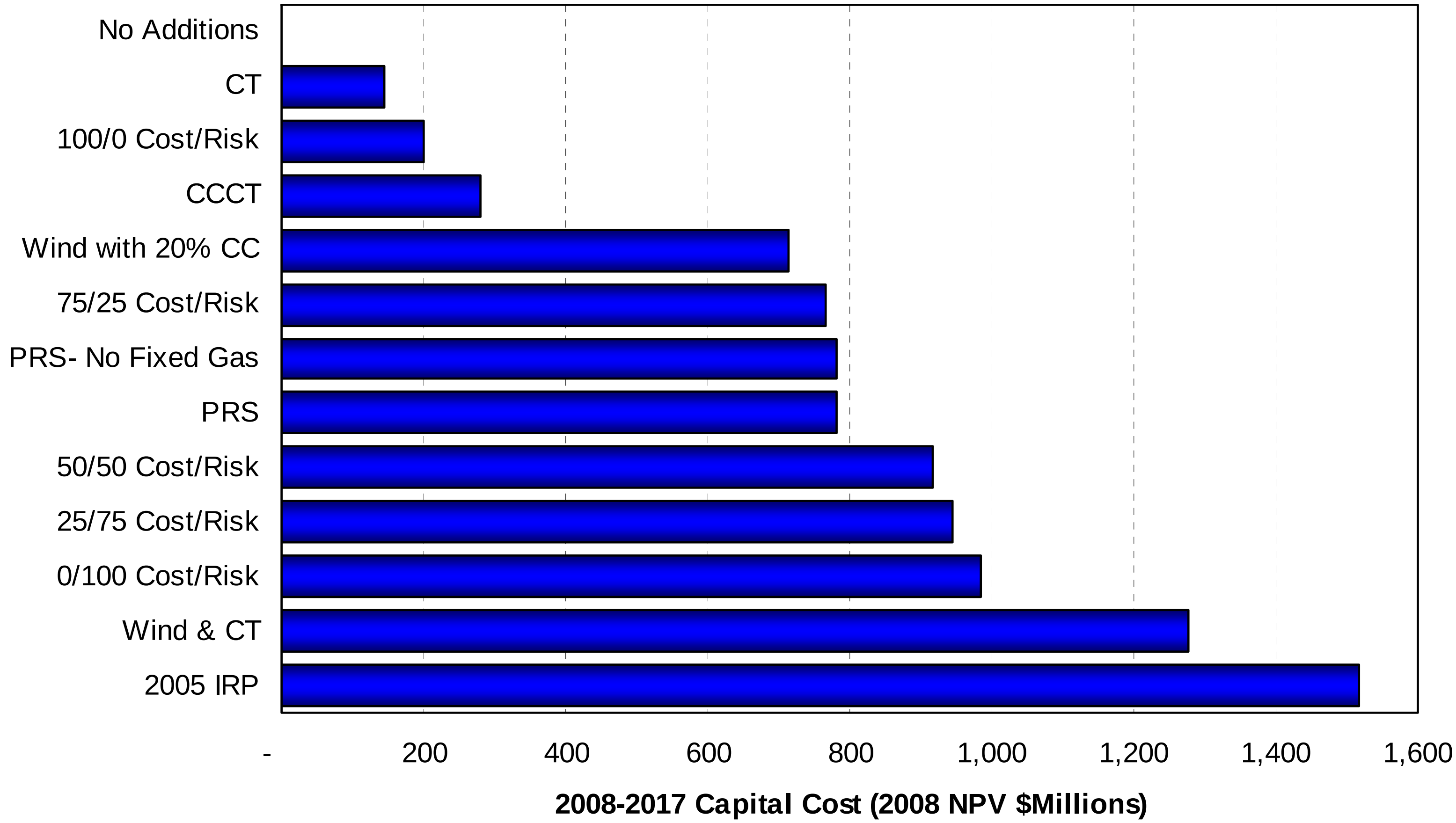
Portfolio Comparison- Avg Increase

Power Supply Related Costs ONLY (2008-2018 timeframe)



Portfolio Comparison- Capital Costs

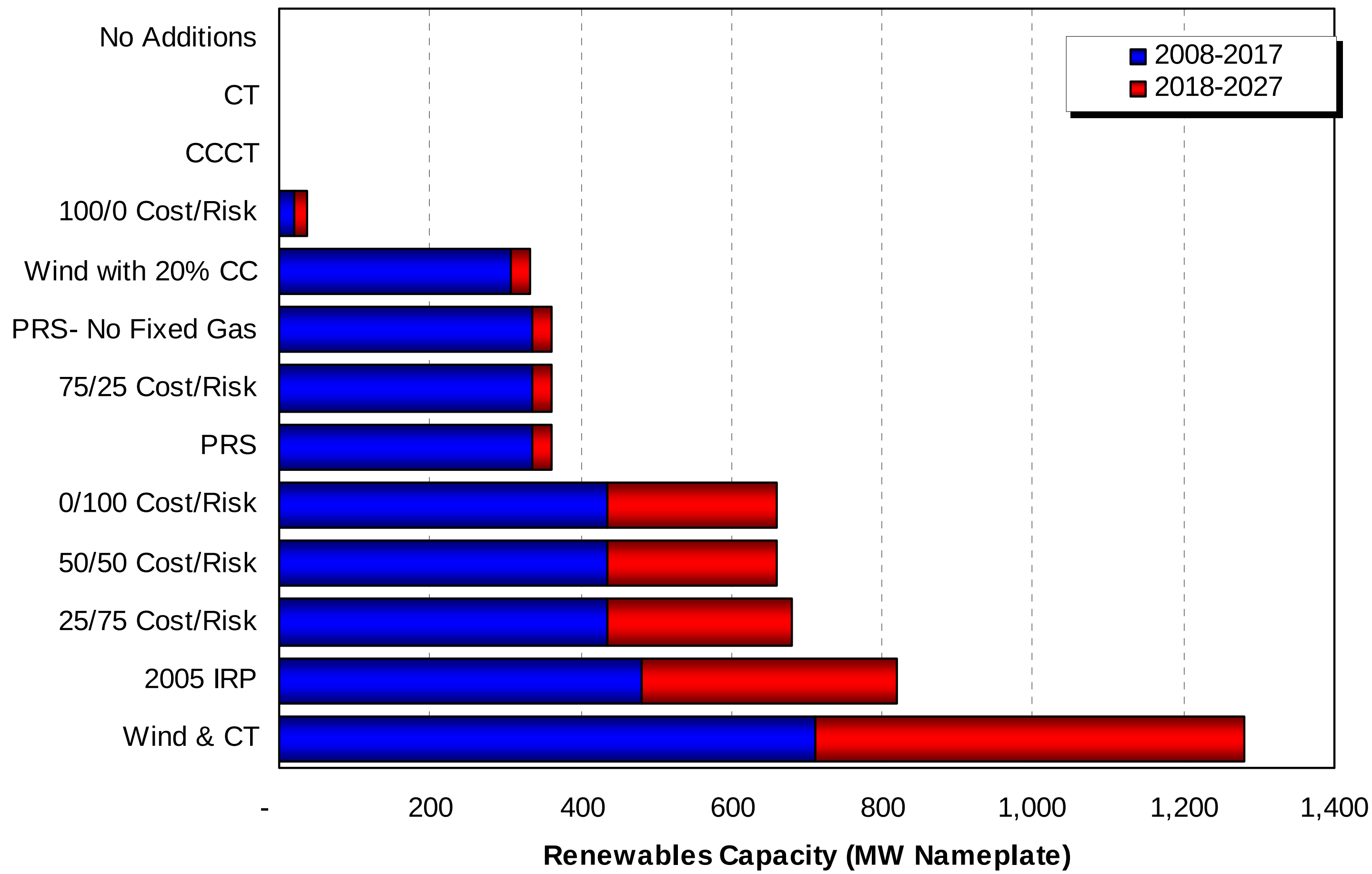
Net Present Value of 2008-2017 Capital Expenditures



PRS may require capital or debt equivalents to stabilize the price of natural gas

Portfolio Comparison- Renewables

Nameplate Renewable Resources



Gas-Fired Combined Cycle With Fixed Gas

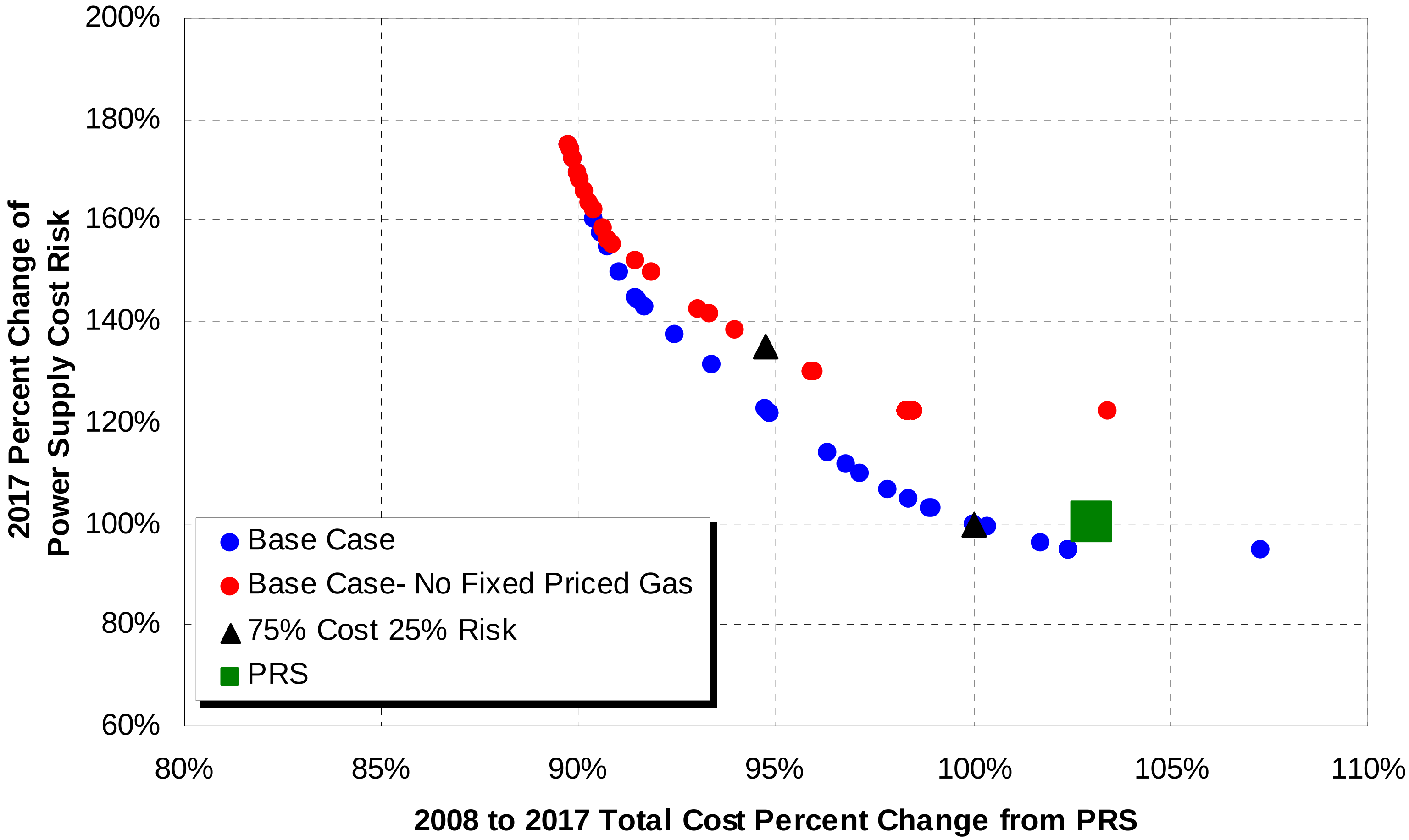
- Medium- to long-term fixed-price gas contract, or
- Could be coal gasified into pipeline-quality gas
  - Provide a significant new source of gas supply
  - Create a sequestered IGCC plant w/o operational trade-offs
    - Remote locations, altitude penalties, gasifier reliability
- Model is flexible in modeling any type of fixed gas price
- Intent of this resource is to illustrate the ability to reduce power cost risk without building a coal resource directly

Base Case/PRS Fixed Gas Assumptions

- Can select resource in any year
- Pay $2 premium above expected gas price
- Purchase 75% of the fuel as fixed
- All combined cycle plants have fixed gas component
- What if:
  - Pay $3.50 gas price premium
  - Pay $5.00 gas price premium
  - All spot market purchases
  - Purchase 25% of fuel as fixed
  - Purchase 100% of fuel as fixed

May need to create new tool to optimize the amount of fuel to be purchased at a fixed price

Efficient Frontier- Fixed NG Gas Price Sensitivity



Fixed Gas Selection Impacts (MW)

75% Cost/25% Risk Portfolio Criteria (2008-2017)

	CCCT	CCCT Fixed	Wind	Other
PRS (75% fixed gas fueling @ $2/dth premium)	0	350	300	35
$3.50 Gas Price Premium (75% fixed gas)	129	221	322	35
$5.00 Gas Price Premium (75% fixed gas)	211	139	400	35
0% Fixed Price Fueling	340	0	300	40
25% Fixed Price Fueling @ $2/dth premium	0	350	300	35
100% Fixed Price Fueling @ $2/dth premium	31	319	257	35

Impacts of Varying Capital Costs

Applied to 25% Risk Reduction Portfolio Criteria

Assumptions: $/kW

Resource	Low	Base Case	High
Wind	1,300	1,884	2,500
Combined Cycle	600	786	1,000
IGCC Coal w/ Sequestration	2,500	3,232	N/A
Alberta Oil Sands	2,000	3,963	N/A

Sensitivity did not change the amount of resource selection

Wind Results

Limit Reached

	2008-2017	2017-2027
Base Case	300	0
Low	400	200
High	143	0

Impacts of Varying Capital Costs (MW)

Quantifies Low Risk Portfolios Changes to Capital Intensive Resources

	50/50	40/60	25/75	0/100
Base Case				
IGCC w/ Seq	0	0	130	101
Alberta Oil Sands	0	0	0	226
IGCC @ 2,500				
IGCC w/ Seq	0	66	299	101
Alberta Oil Sands	0	0	0	226
Oil Sands @ 2,000				
IGCC w/ Seq	0	0	0	101
Alberta Oil Sands	210	226	226	226

Key PRS Message Points

- Meets requirements of I-937 & SB6001
- Conservation up 100% from 2003 IRP, 50% from 2003
- No coal-fired generation, but sequestration possible in outer years
- Higher capital costs reduced renewables contribution by half
- A return to gas-fired resources
- Fixed gas contracts provide significant portfolio benefits, allowing emulation of coal plant characteristics (stable rates)
- Plan guided by linear programming PRSiM model
- Ignoring Q2 surpluses in L&R tabulation increases costs without reducing risk
- Resource acquisition allows approximately a 15% planning margin

Action Items for the 2007 IRP

2007 Electric Integrated Resource Plan

Fifth Technical Advisory Committee Meeting

April 25, 2007

John Lyons

2005 IRP Action Plan

1. Renewable energy and emissions
   - Wind potential study, monitor legislation, research clean coal and sequestration, and assess biomass potential
2. Modeling enhancements
   - 70-year water record and improve Avista Linear Programming Model
3. Transmission modeling and research
   - Maintain existing rights, collaborate with BPA, regional participation, and cost study
4. Conservation
   - Load shifting programs and complete conservation control project

2007 IRP Action Plan – Renewable Energy

Renewable Energy

- Continue to study potential wind sites within service territory
- Study Montana wind resources and transmission issues
- Learn more about non-wind renewables to satisfy RPS requirements

2007 IRP Action Plan – Conservation

- Reevaluate the process of integrating conservation into the IRP
- Study and quantify transmission and distribution efficiency concepts
- Determine potential impacts and costs of load management options currently being reviewed by the Heritage Project
- Develop and quantify the long-term impacts of the recently signed contractual relationship with the Northwest Sustainable Energy for Economic Development organization

2007 IRP Action Plan – Emissions

- Continue to monitor local, state, and federal level rules and regulations concerning power plant emissions. Most notably greenhouse gases.
- Continue to study emissions markets and costs/benefits of participating in an active market like the Chicago Climate Exchange

2007 IRP Action Plan – Modeling and Forecasting Enhancements

- Study potential for fixed gas through financial arrangements or gasified coal
- Continue to study the impact of global warming on the load forecast
- Monitor the following conditions for the load forecast: large load additions, Shoshone county mining developments, and the market penetration of electric cars

2007 IRP Action Plan – Transmission Issues

- Maintain existing transmission rights
- Continue to work with BPA on transmission issues
- Participate in regional and sub-regional transmission planning efforts
- Continue to evaluate the cost of integrating new resources into our system

2007 IRP Action Plan – Other Areas of Interest

Suggestions for Action Items to be developed for the 2009 IRP?

Next Steps

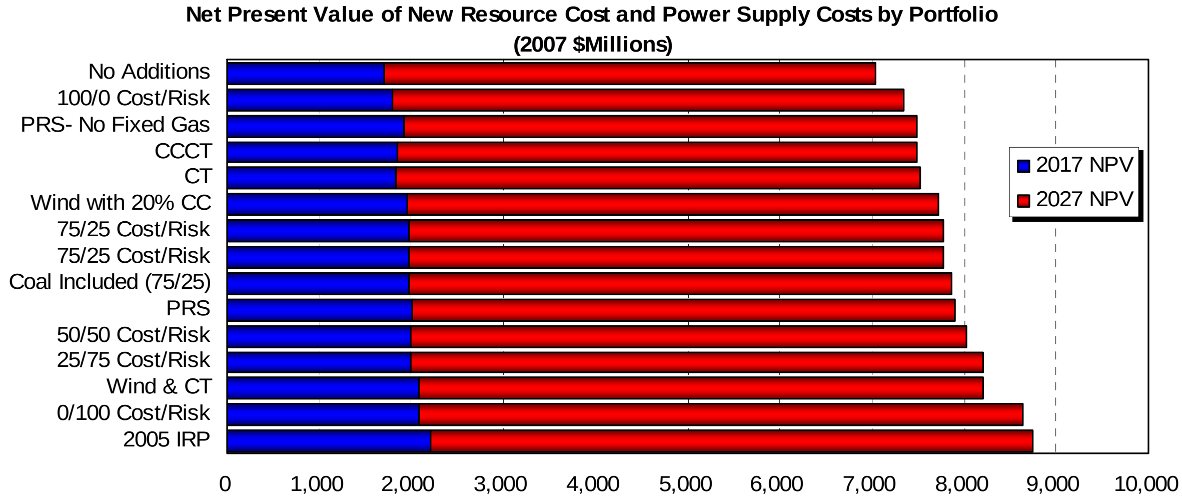
2007 Electric Integrated Resource Plan
Fifth Technical Advisory Committee Meeting
April 25, 2007

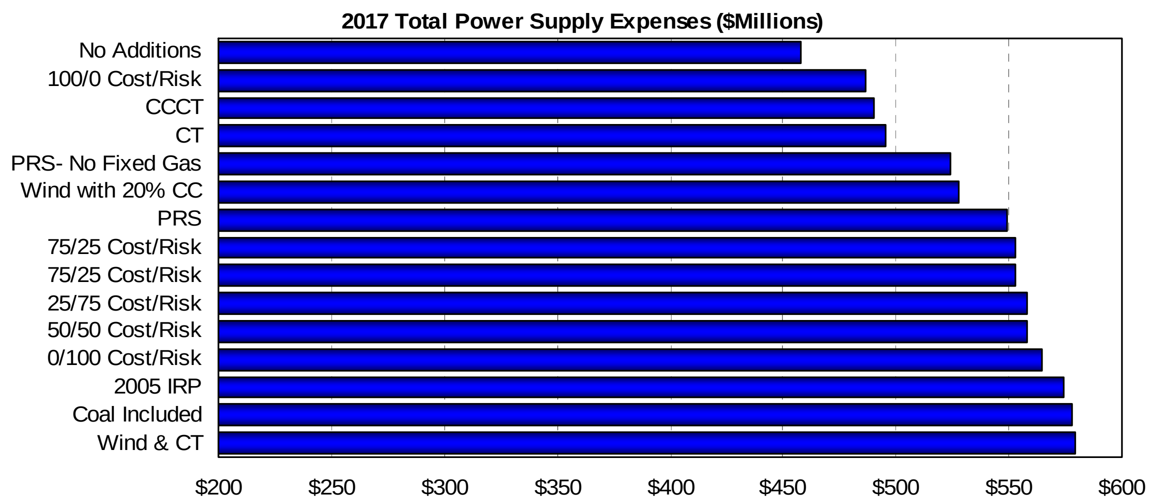
Clint Kalich

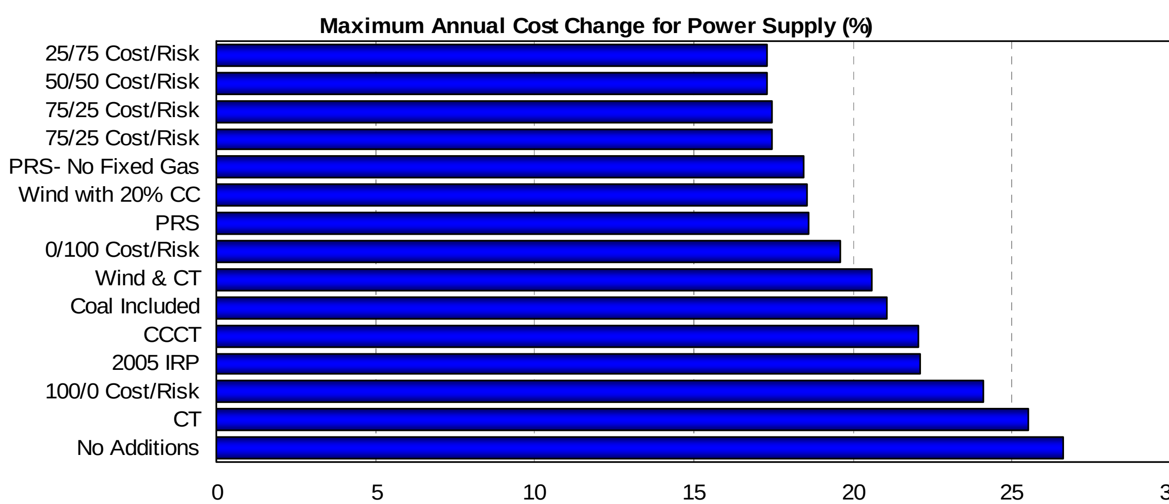
Next Steps

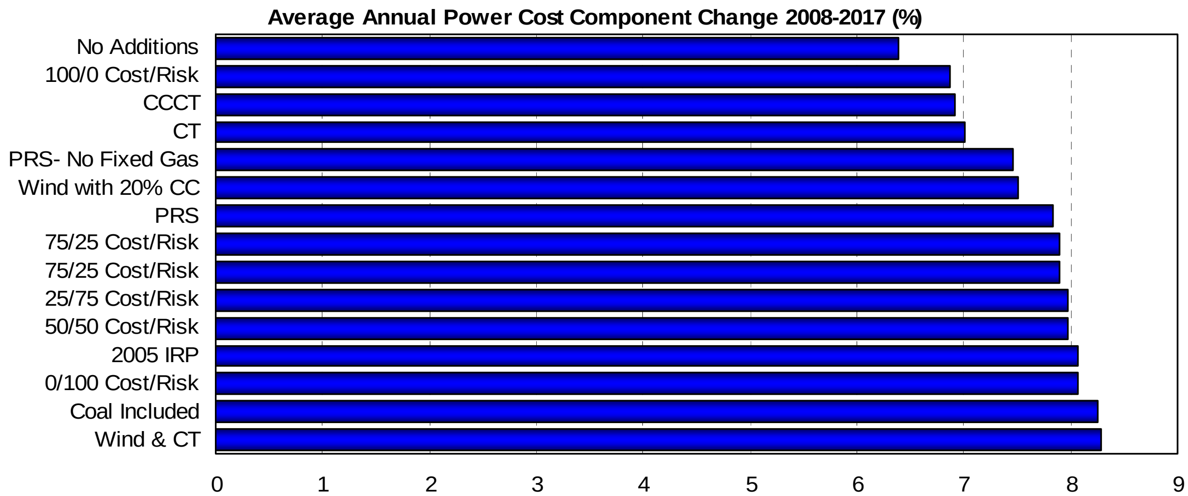
- Management Review Draft Released on Tuesday, May 1
  - Comments back on or before June 1
- Draft IRP Released to TAC Members on Friday, June 15
  - Comments back on or before Friday, July 13
  - Does TAC want to reconvene prior to or on July 13?
- Final 2007 IRP Released August 31
- On to the 2009 IRP!!!

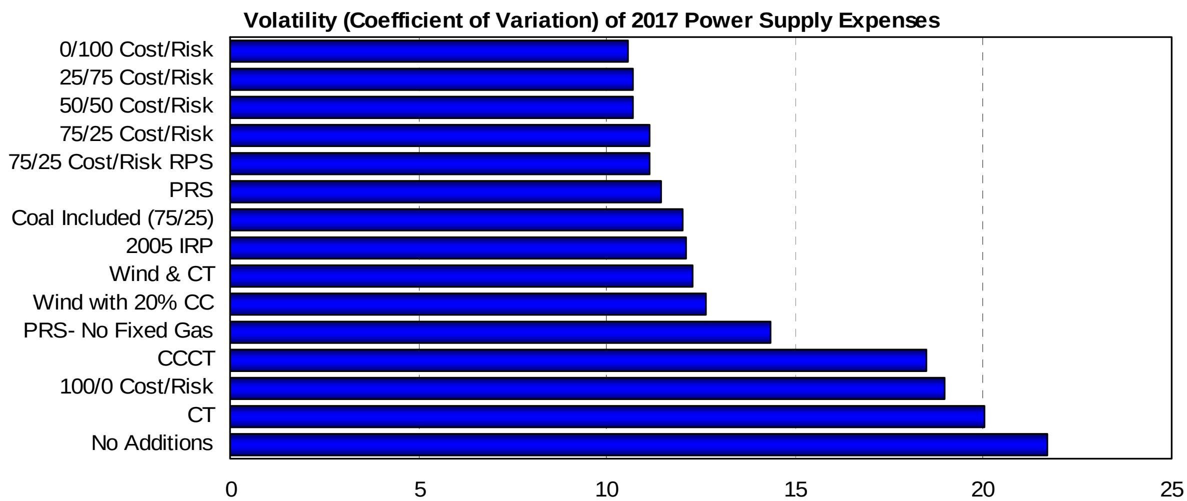
Climate Stewardship Act Future








Average Annual Power Cost Component Change 2008-2017 (%)
No Additions
100/0 Cost/Risk
CCCT
CT
PRS- No Fixed Gas
Wind with 20% CC
PRS
75/25 Cost/Risk
75/25 Cost/Risk
25/75 Cost/Risk
50/50 Cost/Risk
2005 IRP
0/100 Cost/Risk
Coal Included
Wind & CT
0 1 2 3 4 5 6 7 8 9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50/50 Cost/Risk
75/25 Cost/Risk
75/25 Cost/Risk RPS
PRS
Coal Included (75/25)
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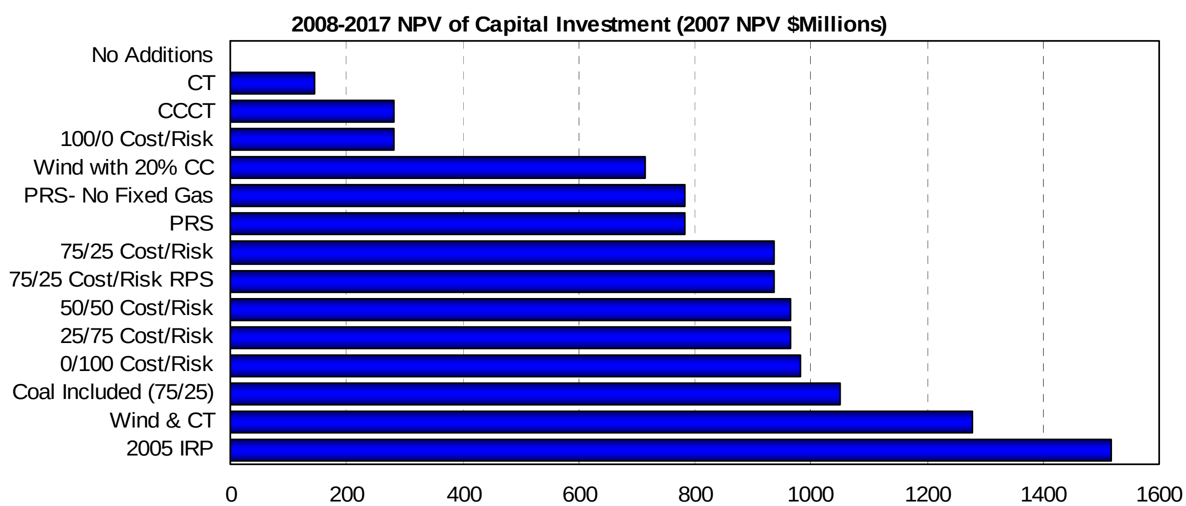
Wind with 20% CC
PRS- No Fixed Gas
CCCT
100/0 Cost/Risk
CT
No Additions
0 5 10 15 20 25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0/100 Cost/Risk
Coal Included (75/25)
Wind & CT
2005 IRP
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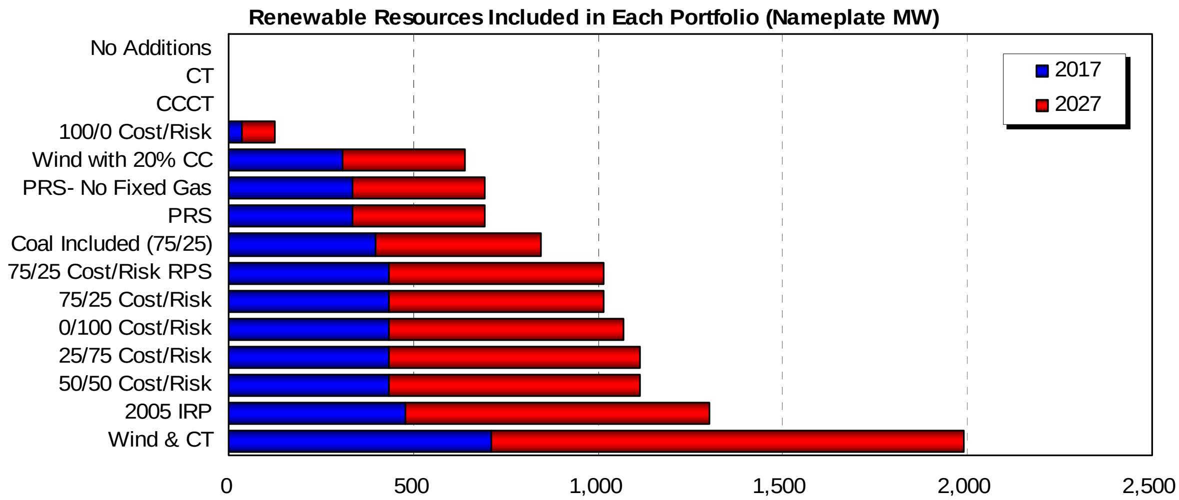
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75/25 Cost/Risk
0/100 Cost/Risk
25/75 Cost/Risk
50/50 Cost/Risk
2005 IRP
Wind & CT
2017
2027
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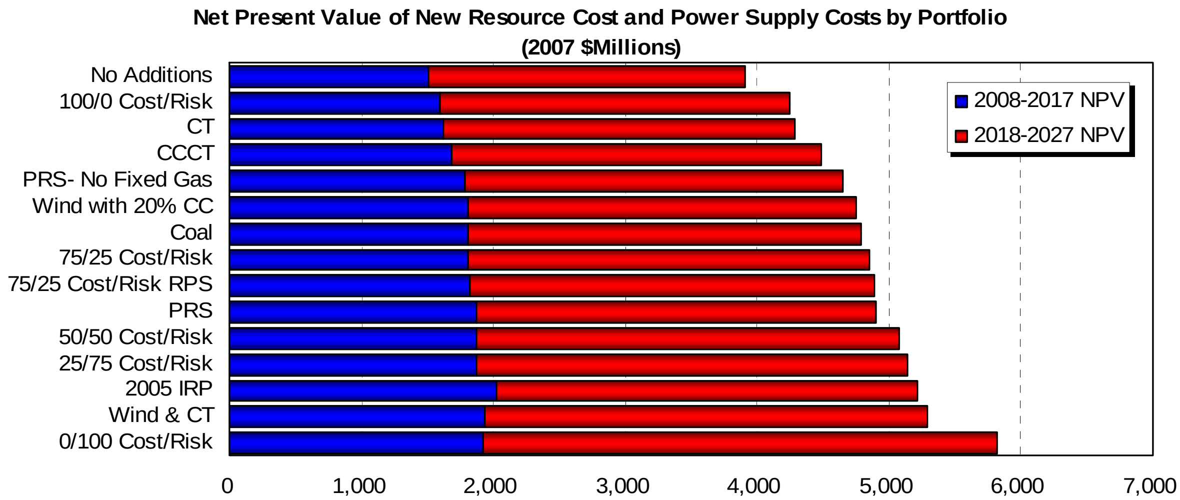
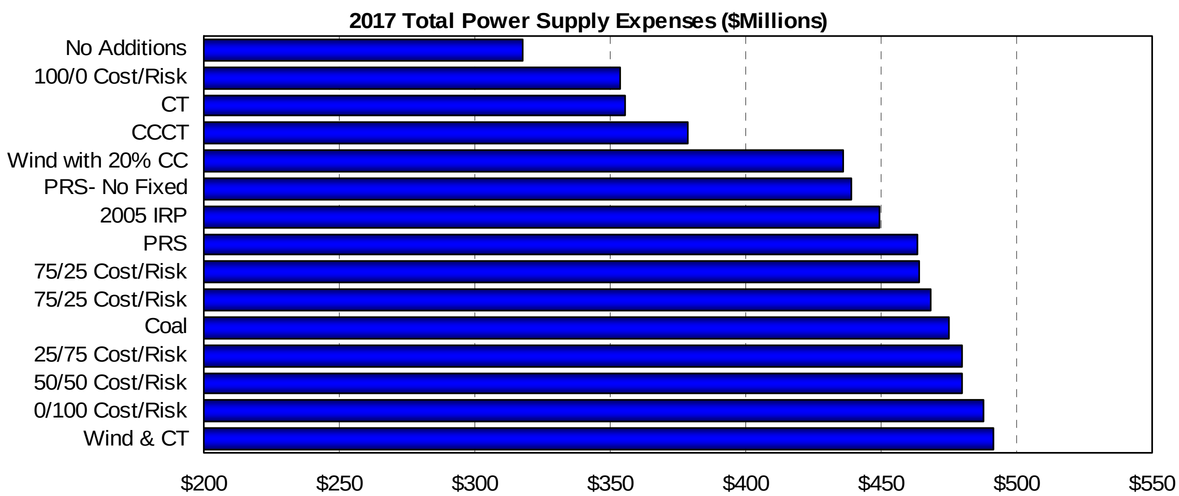
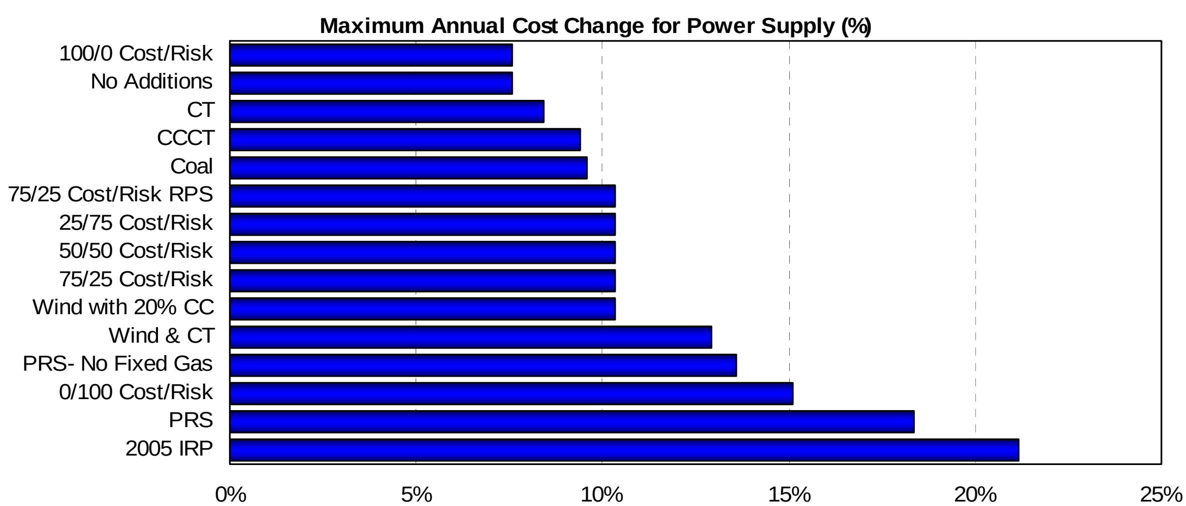
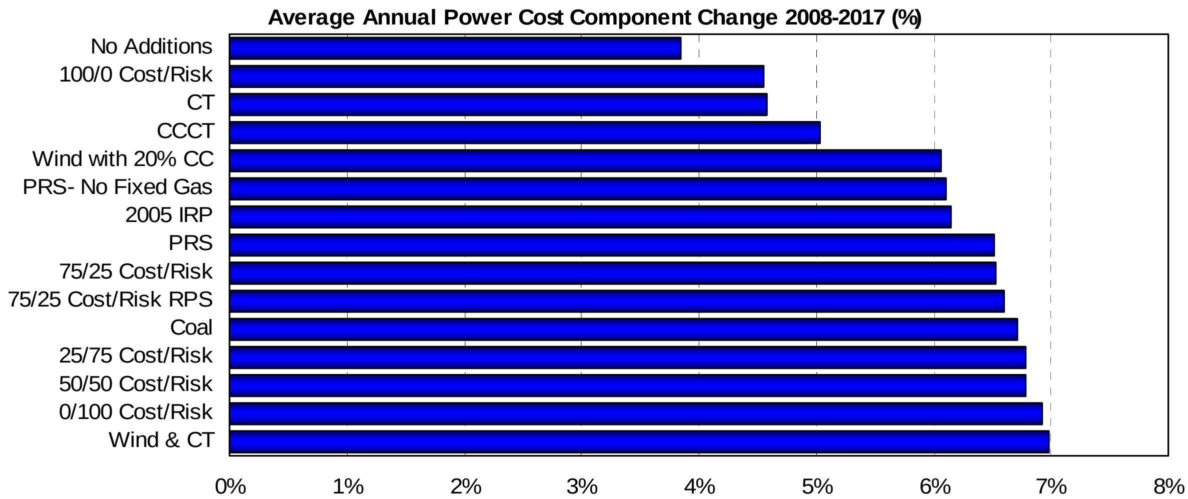
1,500
2,000
2,500

No Carbon Legislation Future





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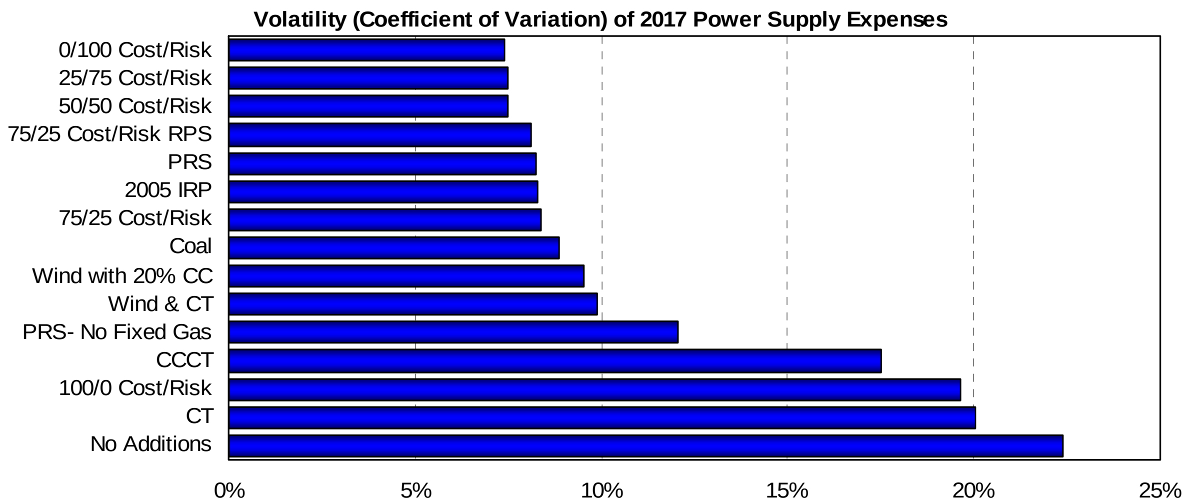
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CCCT
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CT
No Additions
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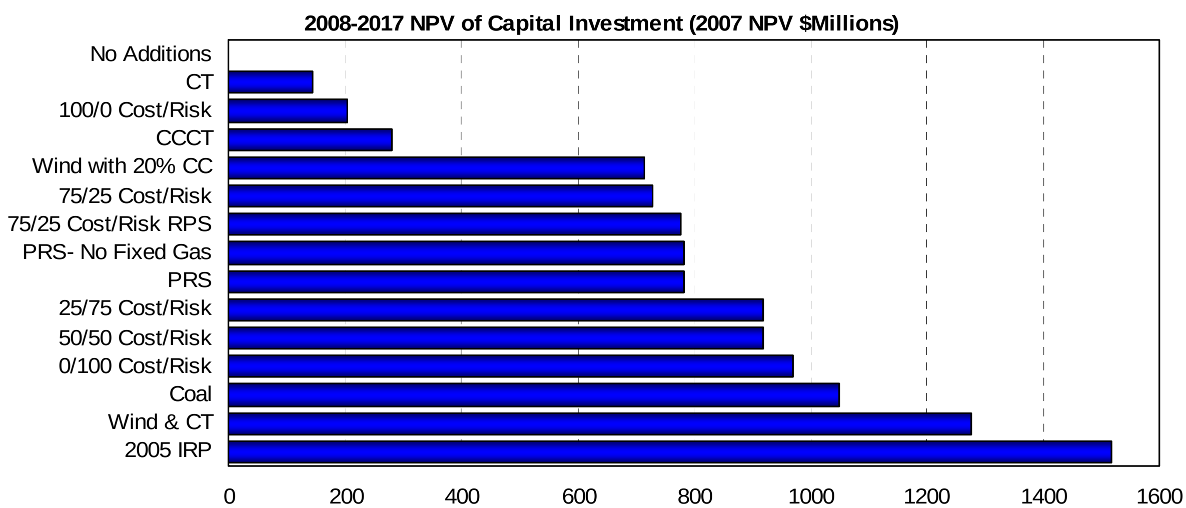
20%
25%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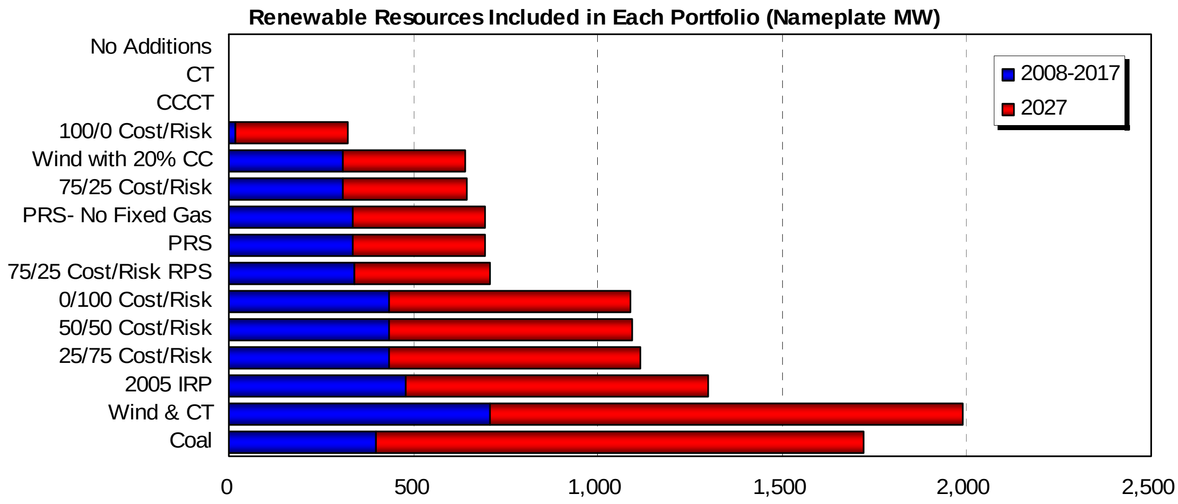
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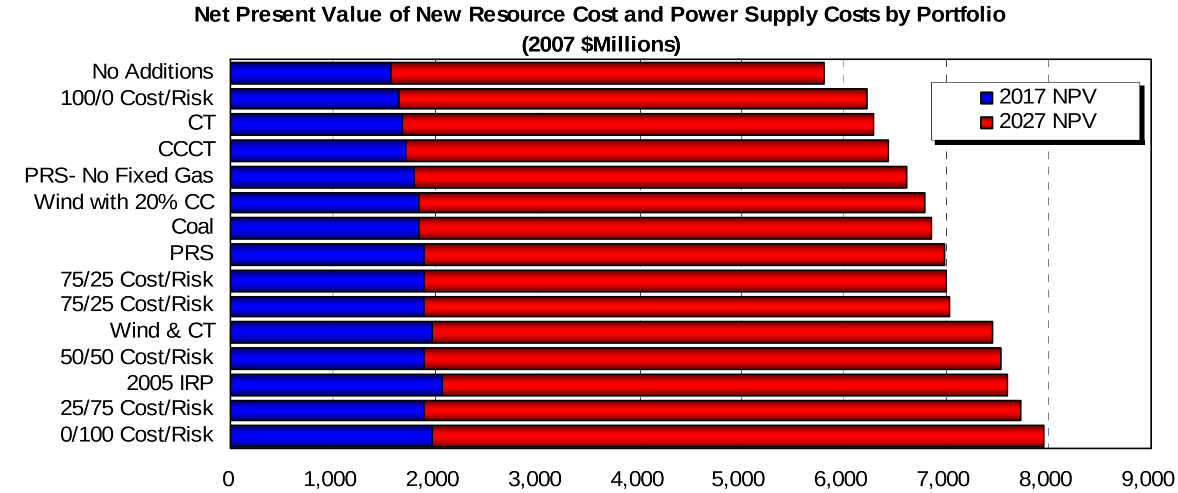
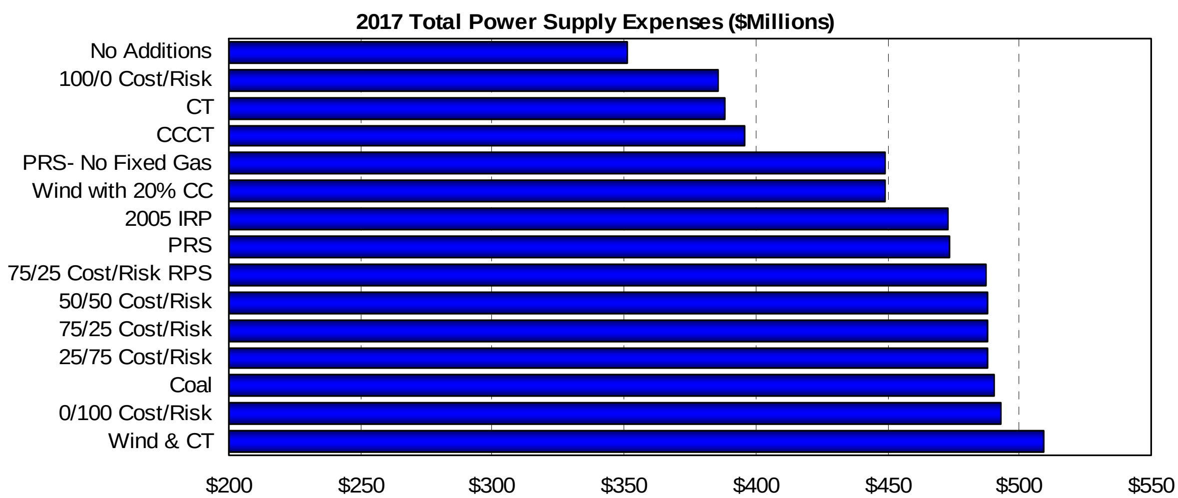
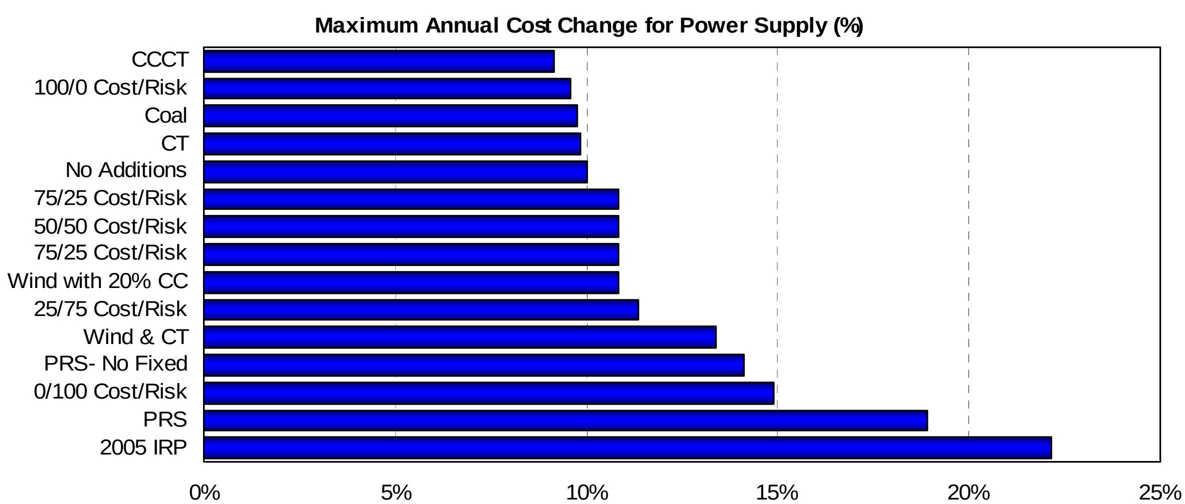
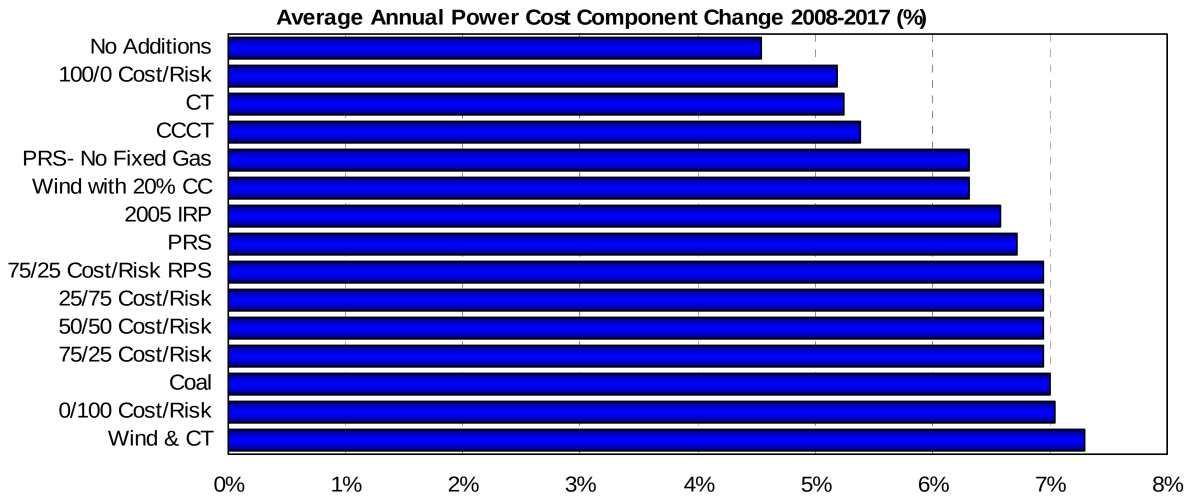
Volatile Gas Future





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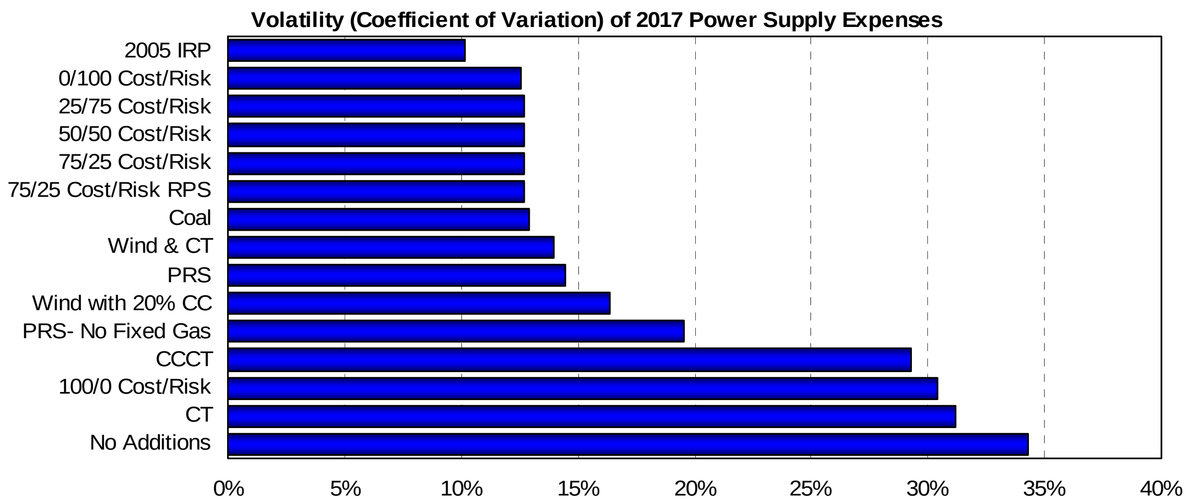
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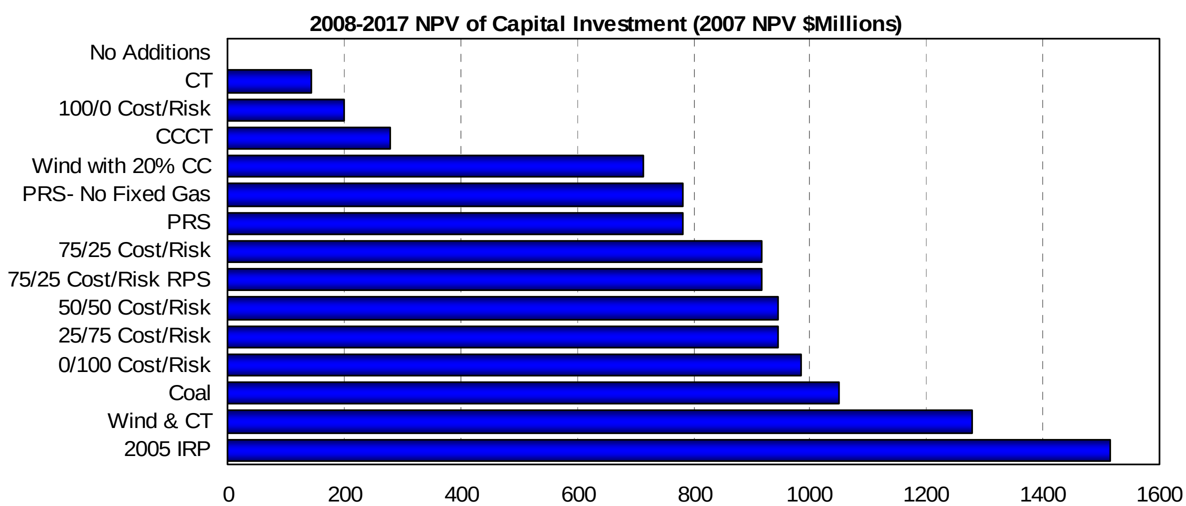
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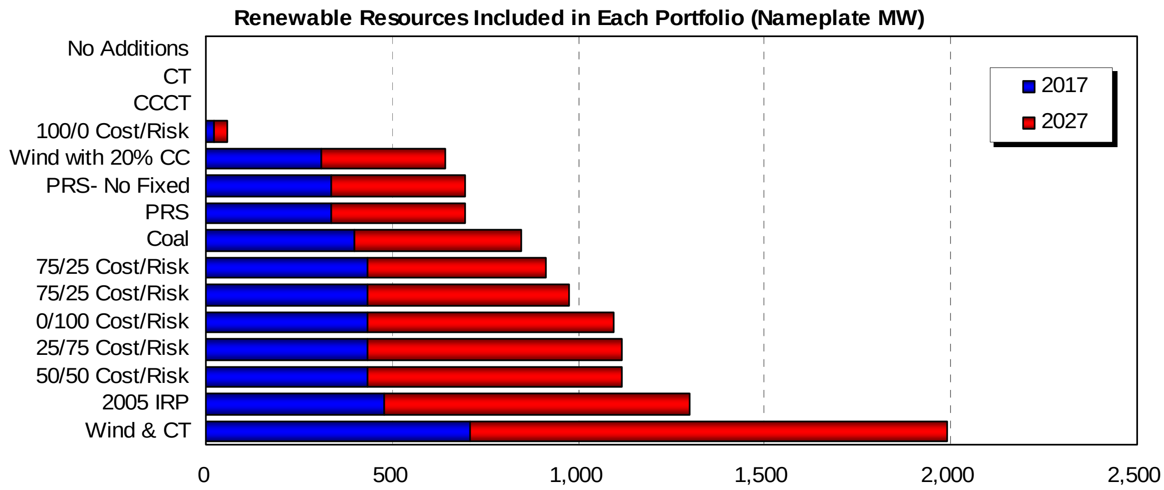
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2005 IRP
Wind & CT
2017
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Summary of the Cost-Effectiveness of Demand-Side Management Measures

The following provide summary statistics for the DSM measures analyzed for the final integrated (demand and supply) resource portfolio.

The files contain a disaggregation of the various components of the avoided cost structure used within the analysis to include the avoided cost of energy as well as transmission, distribution and generation capacity costs. Additional adjustments to the avoided cost for risk and emissions have been included to facilitate direct comparison of demand and supply-side resource options.

The measure's cost, expected life, and energy savings are included in the calculation of the Total Resource Cost (TRC). The TRC has been expressed as a ratio between costs and benefits within the summary sheets as a means of determining the cost-effectiveness of each measure.

Additional graphics indicate the components of each measures total avoided cost.

The 8760-hour load shape of each measure has not been included in the summary sheets due to the sheer volume of data, but an indication of the manner in which the load shape has been applied to derive peak transmission, distribution and generation credits has been included. These three categories are based upon measures that are very likely to peak coincident with system loads ("driver" load profiles, such as air conditioning loads), those whose load shapes are independent of the primary drivers of system load ("non-drivers", such as lighting loads) and those measures that are very likely to be at a zero load during system peak ("non-drivers," such as space heating loads).

Residential Measures

Energy efficient split AC (SEER 12 to 14)

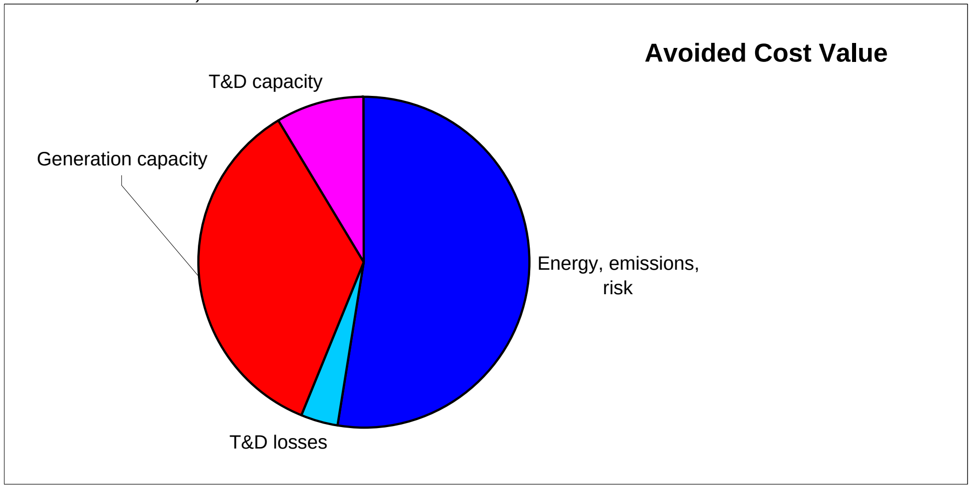
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.548	PV of avoided cost of energy (energy + emissions + risk)	53%	
	$0.036	PV of avoided cost of energy (T&D losses)	3%	
$ 281.00	$ 0.369	PV of avoided cost of generation capacity	35%	
$ 68.42	$ 0.090	PV of avoided cost of T&D capacity	9%	
	$1.042		100%	
			56%	Total energy
			44%	Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0597	Levelized cost/kWh of four energy components of AC
18	Measure life	$0.0469	Levelized cost/kWh of two capacity components of AC
232	Annual kWh savings per unit		
0.1312%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0561%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 127.03	PV of avoided cost of energy (energy + emissions + risk)
$ 8.26	PV of avoided cost of energy (T&D losses)
$ 85.53	PV of avoided cost of generation capacity
$ 20.82	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 241.64	Total Resource Cost test benefits
$ 518.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 518.00	Total Resource Cost test costs
($276)	Net TRC $ amount
0.47	**TRC benefit / cost ratio**

Energy efficient split AC (SEER 12 to 14)



Central air conditioning efficiency tune-up

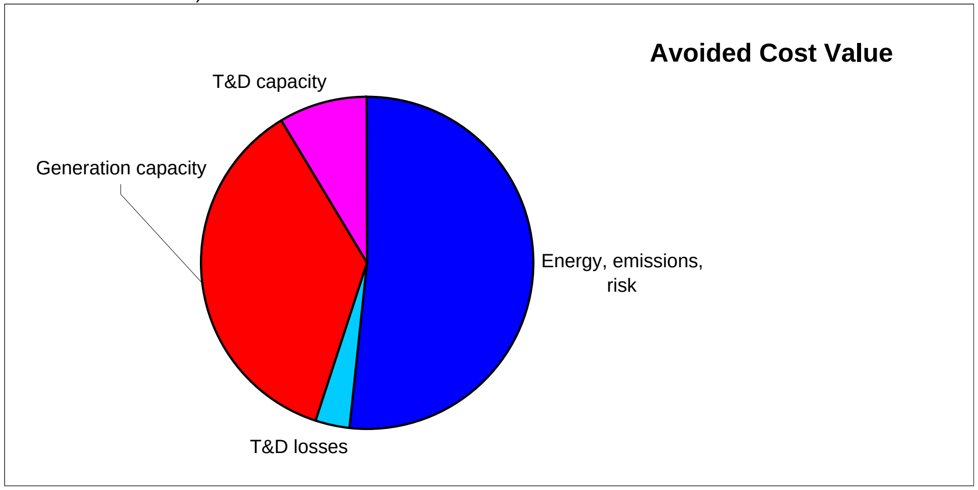
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.192	PV of avoided cost of energy (energy + emissions + risk)	52%
	$0.012	PV of avoided cost of energy (T&D losses)	3%
$ 102.97	$ 0.135	PV of avoided cost of generation capacity	36%
$ 24.42	$ 0.032	PV of avoided cost of T&D capacity	9%
	$0.371		100%
			55% Total energy
			45% Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0503	Levelized cost/kWh of four energy components of AC
5	Measure life	$0.0412	Levelized cost/kWh of two capacity components of AC
125	Annual kWh savings per unit		
0.1312%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0561%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 23.94	PV of avoided cost of energy (energy + emissions + risk)
$ 1.56	PV of avoided cost of energy (T&D losses)
$ 16.89	PV of avoided cost of generation capacity
$ 4.00	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 46.39	Total Resource Cost test benefits
$ 123.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 123.00	Total Resource Cost test costs
($77)	Net TRC $ amount
0.38	**TRC benefit / cost ratio**

Central air conditioning efficiency tune-up



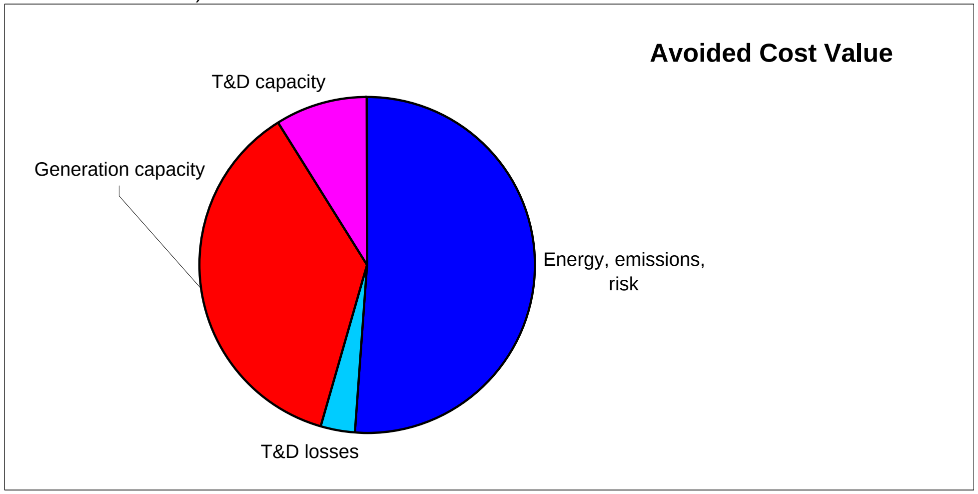
Energy efficient window AC (SEER 12 to 14)

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.338	PV of avoided cost of energy (energy + emissions + risk)	51%	
	$0.022	PV of avoided cost of energy (T&D losses)	3%	
$ 184.47	$ 0.242	PV of avoided cost of generation capacity	37%	
$ 44.23	$ 0.058	PV of avoided cost of T&D capacity	9%	
	$0.660		100%	
			55%	Total energy
driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		45%	Total capacity
7.41%	Discount rate		$0.0523	Levelized cost/kWh of four energy components of AC
10	Measure life		$0.0435	Levelized cost/kWh of two capacity components of AC
127	Annual kWh savings per unit			
0.1312%	Percent of annual energy in maximum hour (use for "driver" measures)			
0.0561%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)			

$ 42.95	PV of avoided cost of energy (energy + emissions + risk)
$ 2.79	PV of avoided cost of energy (T&D losses)
$ 30.73	PV of avoided cost of generation capacity
$ 7.37	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 83.84	Total Resource Cost test benefits
$ 106.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 106.00	Total Resource Cost test costs
($22)	Net TRC $ amount
0.79	**TRC benefit / cost ratio**

Energy efficient window AC (SEER 12 to 14)



Buy back inefficient appliances (to avoid reuse)

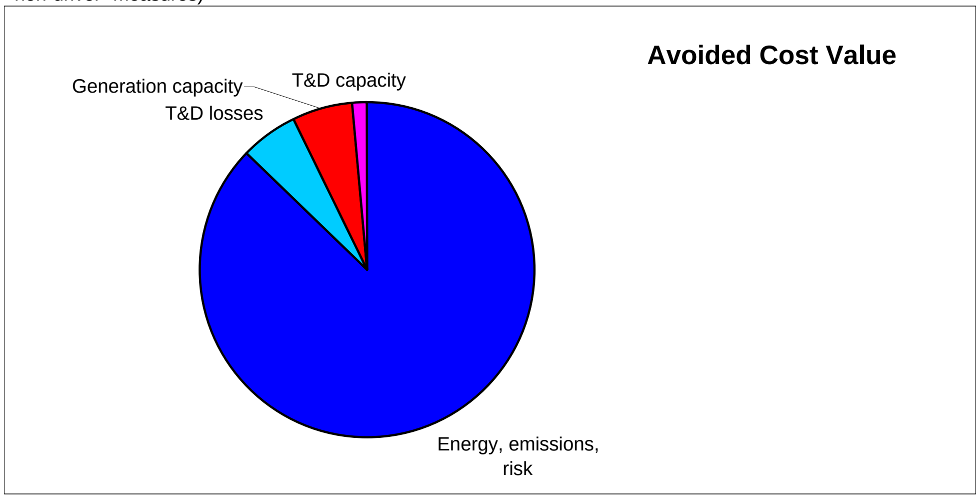
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.233	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.015	PV of avoided cost of energy (T&D losses)	6%
$ 120.83	$ 0.016	PV of avoided cost of generation capacity	6%
$ 28.72	$ 0.004	PV of avoided cost of T&D capacity	1%
	$0.267		100%
			93% Total energy
			7% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0526	Levelized cost/kWh of four energy components of AC
6	Measure life	$0.0041	Levelized cost/kWh of two capacity components of AC
625	Annual kWh savings per unit		
0.0148%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0129%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 145.39	PV of avoided cost of energy (energy + emissions + risk)
$ 9.45	PV of avoided cost of energy (T&D losses)
$ 9.74	PV of avoided cost of generation capacity
$ 2.32	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 166.90	Total Resource Cost test benefits
$ 100.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 100.00	Total Resource Cost test costs
$67	Net TRC $ amount
1.67	**TRC benefit / cost ratio**

Buy back inefficient appliances (to avoid reuse)



Caulking and weatherstripping (single family, resistance)

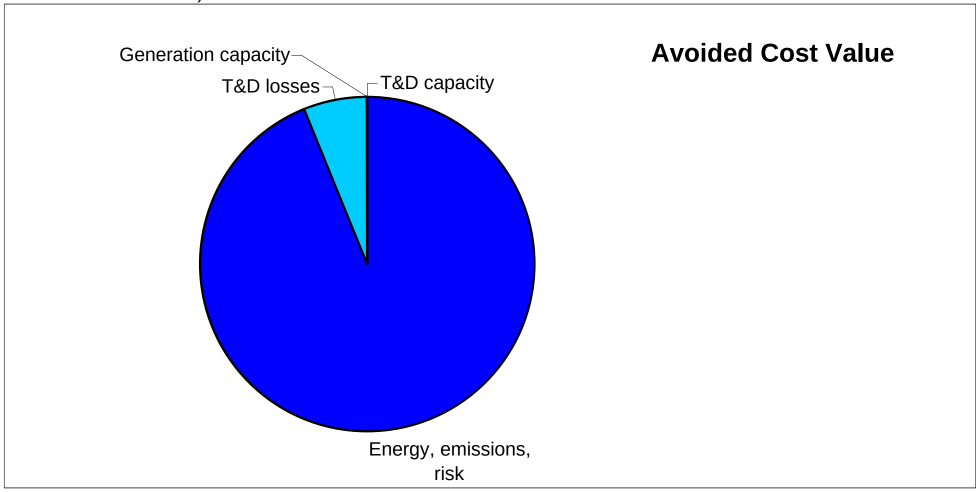
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.371	PV of avoided cost of energy (energy + emissions + risk)	94%	
	$0.024	PV of avoided cost of energy (T&D losses)	6%	
$ 184.47	$ -	PV of avoided cost of generation capacity	0%	
$ 44.23	$ -	PV of avoided cost of T&D capacity	0%	
	$0.395		100%	
			100%	Total energy

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)	0%	Total capacity
7.41%	Discount rate	$0.0573	Levelized cost/kWh of four energy components of AC
10	Measure life	$0.0000	Levelized cost/kWh of two capacity components of AC
798	Annual kWh savings per unit		
0.0019%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0000%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 296.14	PV of avoided cost of energy (energy + emissions + risk)
$ 19.25	PV of avoided cost of energy (T&D losses)
$ -	PV of avoided cost of generation capacity
$ -	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 315.39	Total Resource Cost test benefits
$ 650.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 650.00	Total Resource Cost test costs
($335)	Net TRC $ amount
0.49	**TRC benefit / cost ratio**

Caulking and weatherstripping (single family, resistance)



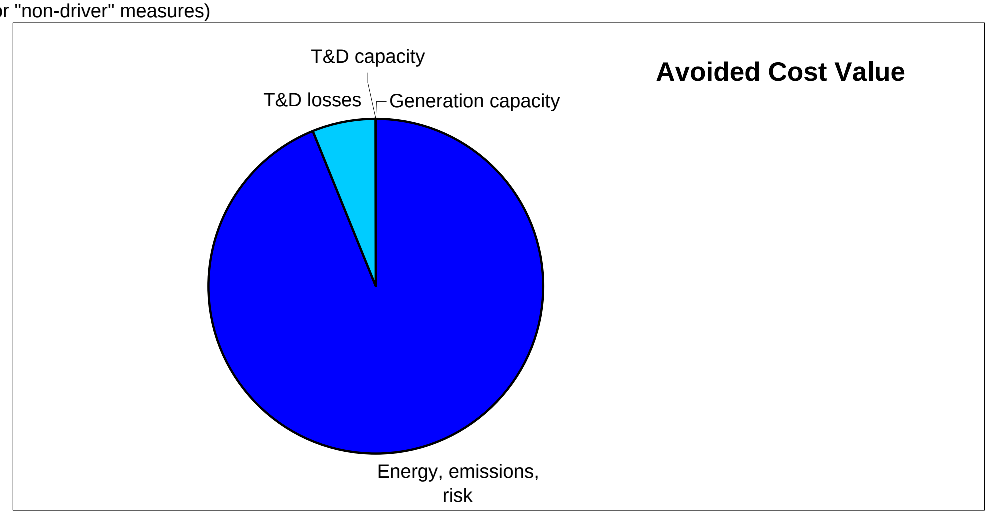
Central heat pump efficiency tune-up

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.245	PV of avoided cost of energy (energy + emissions + risk)	94%	
	$0.016	PV of avoided cost of energy (T&D losses)	6%	
$ 120.83	$ -	PV of avoided cost of generation capacity	0%	
$ 28.72	$ -	PV of avoided cost of T&D capacity	0%	
	$0.260		100%	
			100%	Total energy
zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		0%	Total capacity
7.41%	Discount rate		$0.0553	Levelized cost/kWh of four energy components of AC
6	Measure life		$0.0000	Levelized cost/kWh of two capacity components of AC
478	Annual kWh savings per unit			
0.0019%	Percent of annual energy in maximum hour (use for "driver" measures)			
0.0000%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)			

$ 116.91	PV of avoided cost of energy (energy + emissions + risk)
$ 7.60	PV of avoided cost of energy (T&D losses)
$ -	PV of avoided cost of generation capacity
$ -	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 124.51	Total Resource Cost test benefits
$ 123.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 123.00	Total Resource Cost test costs
$2	Net TRC $ amount
1.01	**TRC benefit / cost ratio**

Central heat pump efficiency tune-up



Duct insulation retrofit (R3-R8, single family, resistance)

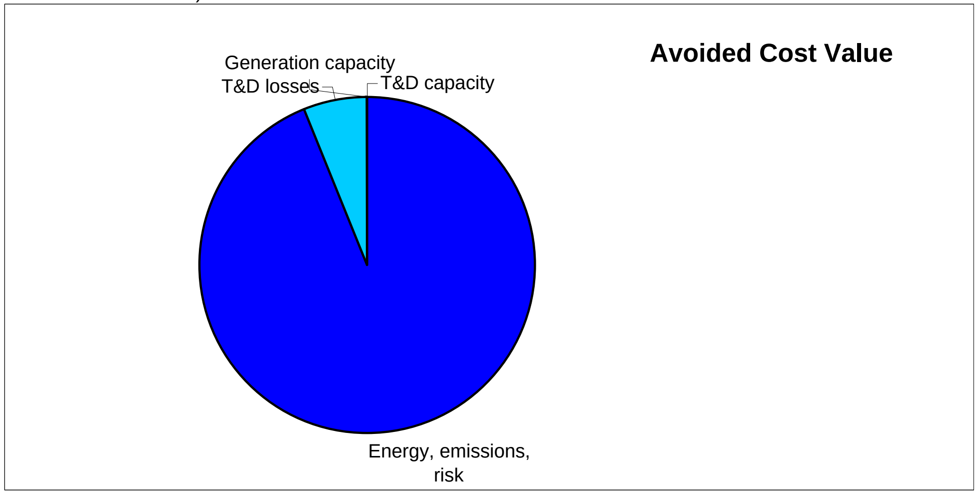
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.836	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.054	PV of avoided cost of energy (T&D losses)	6%
$ 372.36	$ -	PV of avoided cost of generation capacity	0%
$ 92.43	$ -	PV of avoided cost of T&D capacity	0%
	$0.890		100%
			100% Total energy
			0% Total capacity

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0747	Levelized cost/kWh of four energy components of AC
30	Measure life	$0.0000	Levelized cost/kWh of two capacity components of AC
1,134	Annual kWh savings per unit		
0.0019%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0000%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 947.54	PV of avoided cost of energy (energy + emissions + risk)
$ 61.59	PV of avoided cost of energy (T&D losses)
$ -	PV of avoided cost of generation capacity
$ -	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 1,009.13	Total Resource Cost test benefits
$ 518.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 518.00	Total Resource Cost test costs
$491	Net TRC $ amount
1.95	**TRC benefit / cost ratio**

Duct insulation retrofit (R3-R8, single family, resistance)



Duct sealing (single family, resistance)

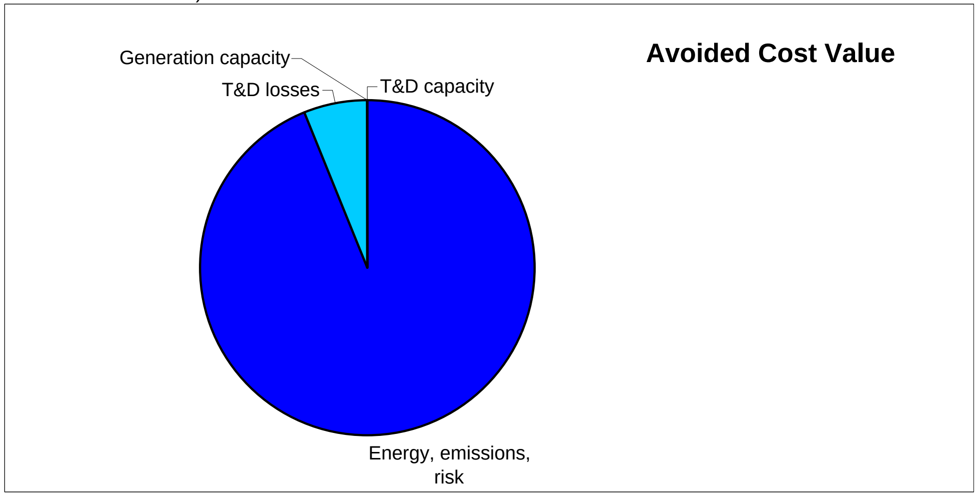
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.642	PV of avoided cost of energy (energy + emissions + risk)	94%	
	$0.042	PV of avoided cost of energy (T&D losses)	6%	
$ 300.00	$ -	PV of avoided cost of generation capacity	0%	
$ 73.31	$ -	PV of avoided cost of T&D capacity	0%	
	$0.683		100%	
			100%	Total energy
			0%	Total capacity

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0666	Levelized cost/kWh of four energy components of AC
20	Measure life	$0.0000	Levelized cost/kWh of two capacity components of AC
1,007	Annual kWh savings per unit		
0.0019%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0000%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 646.19	PV of avoided cost of energy (energy + emissions + risk)
$ 42.00	PV of avoided cost of energy (T&D losses)
$ -	PV of avoided cost of generation capacity
$ -	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 688.19	Total Resource Cost test benefits
$ 750.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 750.00	Total Resource Cost test costs
($62)	Net TRC $ amount
0.92	**TRC benefit / cost ratio**

Duct sealing (single family, resistance)



Electric vs gas clothes dryer

Summarization of AC benefits and comparison to TRC costs

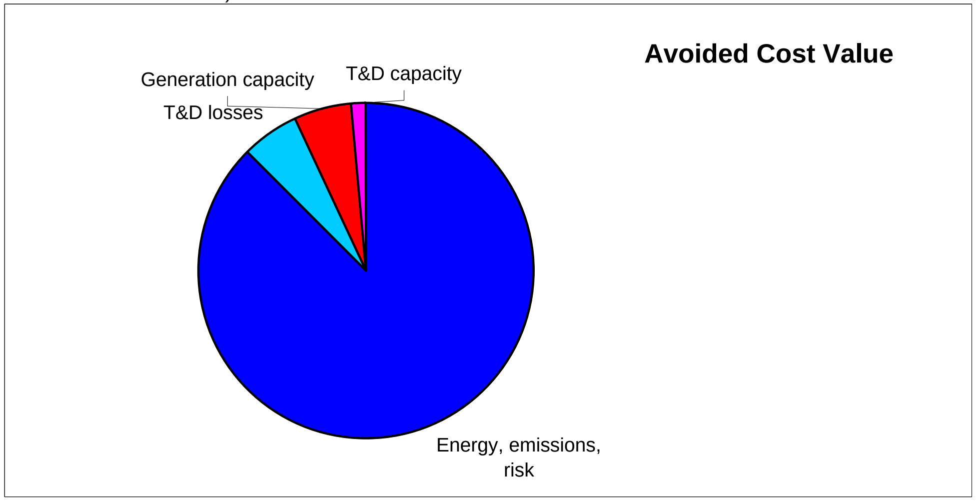
Per first year kW	Per first year kWh		% of total value
	$0.478	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.031	PV of avoided cost of energy (T&D losses)	6%
$ 237.24	$ 0.030	PV of avoided cost of generation capacity	6%
$ 57.34	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.547		100%
			93% Total energy
			7% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
14	Measure life
479	Annual kWh savings per unit
0.0155%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0127%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0597	Levelized cost/kWh of four energy components of AC
$0.0044	Levelized cost/kWh of two capacity components of AC

$229	PV of avoided cost of energy (energy + emissions + risk)
$15	PV of avoided cost of energy (T&D losses)
$14	PV of avoided cost of generation capacity
$3	PV of avoided cost of T&D capacity
$0	PV of avoided cost of natural gas
$0	PV of non-energy benefits
$262	Total Resource Cost test benefits
$200.00	Incremental customer cost
$0	Incremental non-incentive utility cost
$200	Total Resource Cost test costs
$62	Net TRC $ amount
1.31	**TRC benefit / cost ratio**

Electric vs gas clothes dryer



Electric vs HE gas water heater

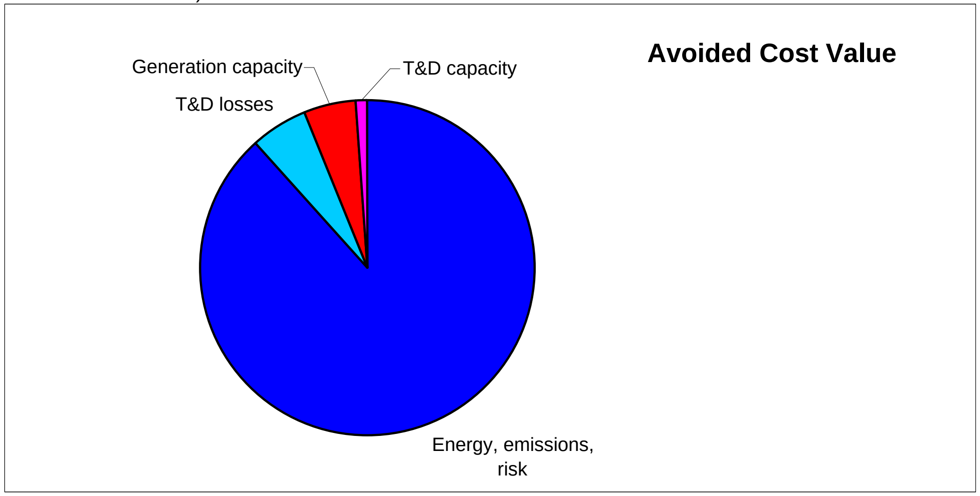
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.513	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.581		100%
			94% Total energy
			6% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0615	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0040	Levelized cost/kWh of two capacity components of AC
5,131	Annual kWh savings per unit		
0.0160%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0113%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$	2,630.25	PV of avoided cost of energy (energy + emissions + risk)
$	170.97	PV of avoided cost of energy (T&D losses)
$	144.90	PV of avoided cost of generation capacity
$	35.09	PV of avoided cost of T&D capacity
$	-	PV of avoided cost of natural gas
$	-	PV of non-energy benefits
$	2,981.20	Total Resource Cost test benefits
$	512.00	Incremental customer cost
$	-	Incremental non-incentive utility cost
$	512.00	Total Resource Cost test costs
	$2,469	Net TRC $ amount
	5.82	**TRC benefit / cost ratio**

Electric vs HE gas water heater



More efficient pumps for domestic water systems

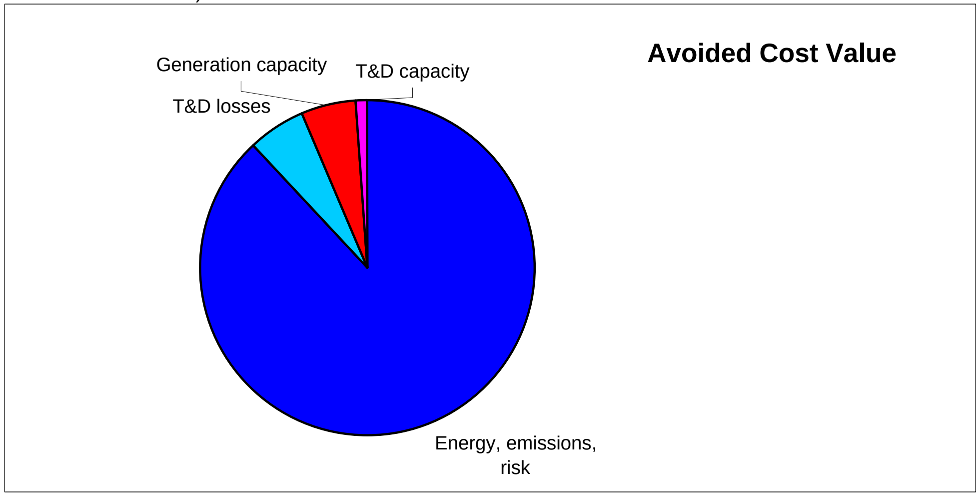
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.496	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.032	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.564		100%
			94% Total energy
			6% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0595	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0040	Levelized cost/kWh of two capacity components of AC
250	Annual kWh savings per unit		
0.0125%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0114%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 124.03	PV of avoided cost of energy (energy + emissions + risk)
$ 8.06	PV of avoided cost of energy (T&D losses)
$ 7.09	PV of avoided cost of generation capacity
$ 1.72	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 140.90	Total Resource Cost test benefits
$ 200.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 200.00	Total Resource Cost test costs
($59)	Net TRC $ amount
0.70	**TRC benefit / cost ratio**

More efficient pumps for domestic water systems



Energy Star Home

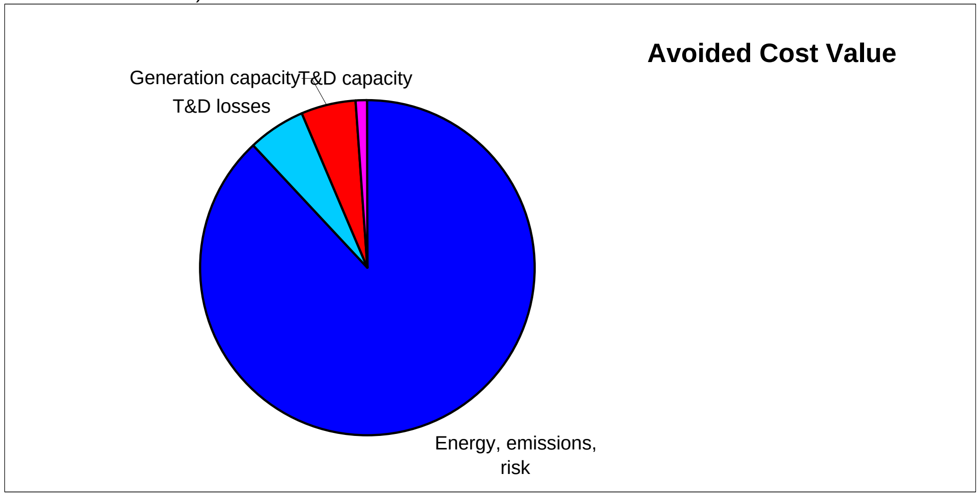
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.496	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.032	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.564		100%
			94% Total energy
			6% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0595	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0040	Levelized cost/kWh of two capacity components of AC
1,800	Annual kWh savings per unit		
0.0125%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0114%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 893.01	PV of avoided cost of energy (energy + emissions + risk)
$ 58.05	PV of avoided cost of energy (T&D losses)
$ 51.05	PV of avoided cost of generation capacity
$ 12.36	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 1,014.47	Total Resource Cost test benefits
$ 3,500.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 3,500.00	Total Resource Cost test costs
($2,486)	Net TRC $ amount
0.29	**TRC benefit / cost ratio**

Energy Star Home



Exterior doors (retrofit)

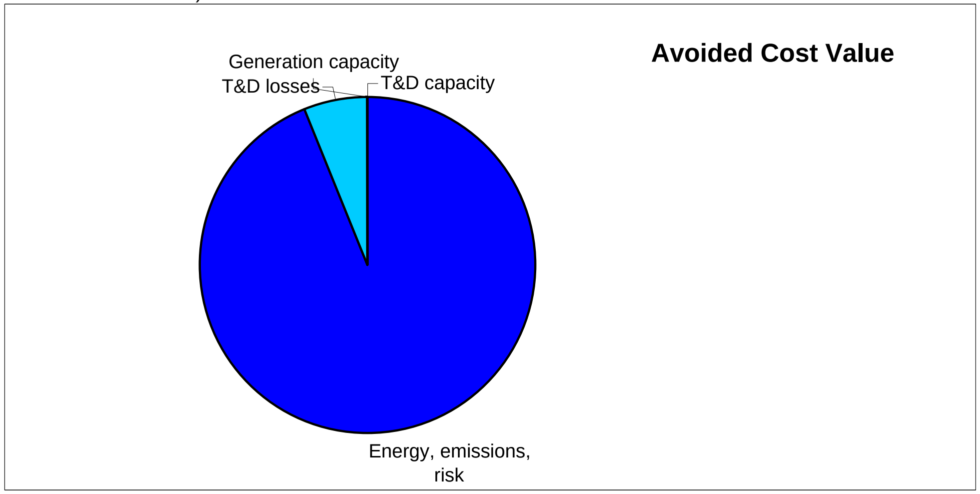
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.516	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.034	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ -	PV of avoided cost of generation capacity	0%
$ 60.28	$ -	PV of avoided cost of T&D capacity	0%
	$0.550		100%
			100% Total energy
			0% Total capacity

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0619	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0000	Levelized cost/kWh of two capacity components of AC
300	Annual kWh savings per unit		
0.0019%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0000%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 154.88	PV of avoided cost of energy (energy + emissions + risk)
$ 10.07	PV of avoided cost of energy (T&D losses)
$ -	PV of avoided cost of generation capacity
$ -	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 164.94	Total Resource Cost test benefits
$ 250.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 250.00	Total Resource Cost test costs
($85)	Net TRC $ amount
0.66	**TRC benefit / cost ratio**

Exterior doors (retrofit)



Faucet aerator (single and multi-family)

Summarization of AC benefits and comparison to TRC costs

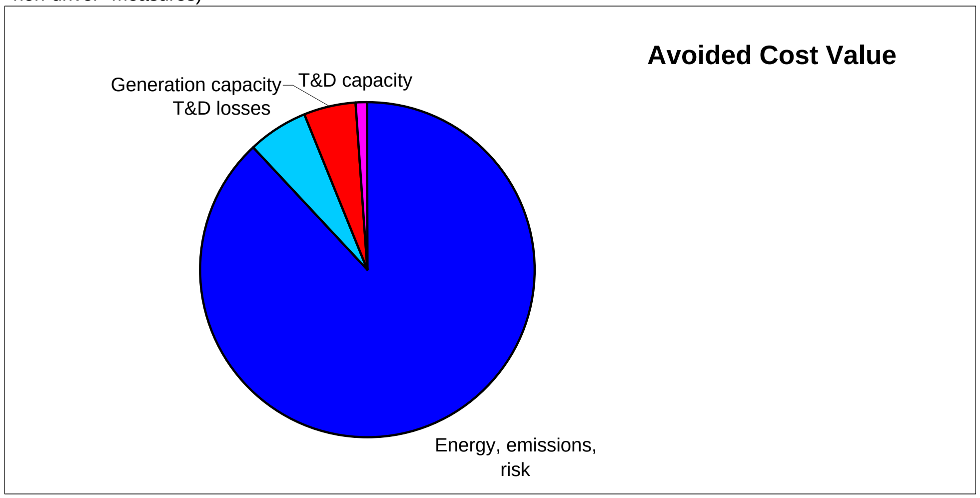
Per first year kW	Per first year kWh		% of total value
	$0.337	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.022	PV of avoided cost of energy (T&D losses)	6%
$ 169.66	$ 0.019	PV of avoided cost of generation capacity	5%
$ 40.59	$ 0.005	PV of avoided cost of T&D capacity	1%
	$0.383		100%
			94% Total energy
			6% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
9	Measure life
76	Annual kWh savings per unit
0.0160%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0113%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0561	Levelized cost/kWh of four energy components of AC
$0.0037	Levelized cost/kWh of two capacity components of AC

$ 25.61	PV of avoided cost of energy (energy + emissions + risk)
$ 1.66	PV of avoided cost of energy (T&D losses)
$ 1.46	PV of avoided cost of generation capacity
$ 0.35	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 29.09	Total Resource Cost test benefits
$ 12.69	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 12.69	Total Resource Cost test costs
$16	Net TRC $ amount
2.29	**TRC benefit / cost ratio**

Faucet aerator (single and multi-family)



Fireplace dampers (WA/ID) (chimney-top, electric heat)

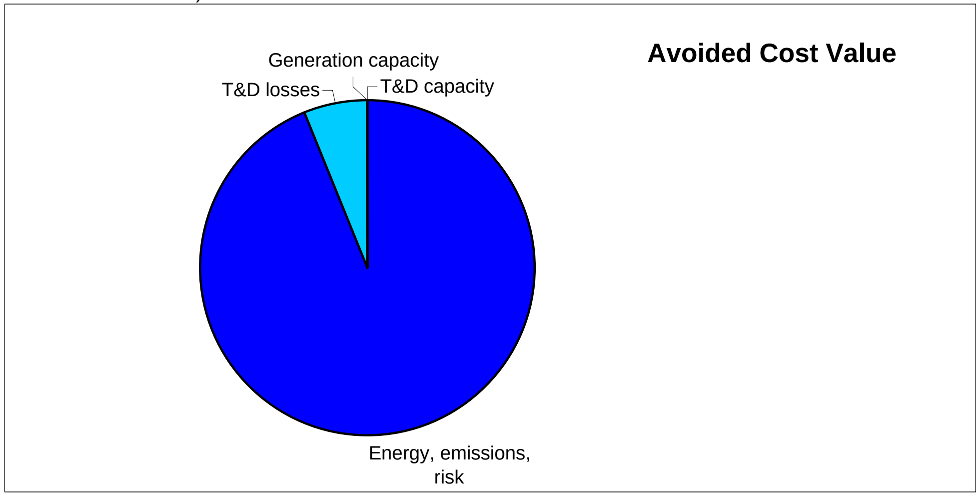
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.516	PV of avoided cost of energy (energy + emissions + risk)	94%	
	$0.034	PV of avoided cost of energy (T&D losses)	6%	
$ 248.96	$ -	PV of avoided cost of generation capacity	0%	
$ 60.28	$ -	PV of avoided cost of T&D capacity	0%	
	$0.550		100%	
			100%	Total energy

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)	0%	Total capacity
7.41%	Discount rate	$0.0619	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0000	Levelized cost/kWh of two capacity components of AC
2,390	Annual kWh savings per unit		
0.0019%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0000%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 1,233.84	PV of avoided cost of energy (energy + emissions + risk)
$ 80.20	PV of avoided cost of energy (T&D losses)
$ -	PV of avoided cost of generation capacity
$ -	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 1,314.04	Total Resource Cost test benefits
$ 500.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 500.00	Total Resource Cost test costs
$814	Net TRC $ amount
2.63	**TRC benefit / cost ratio**

Fireplace dampers (WA/ID) (chimney-top, electric heat)



Electric furnace vs condensing gas space heat conversion

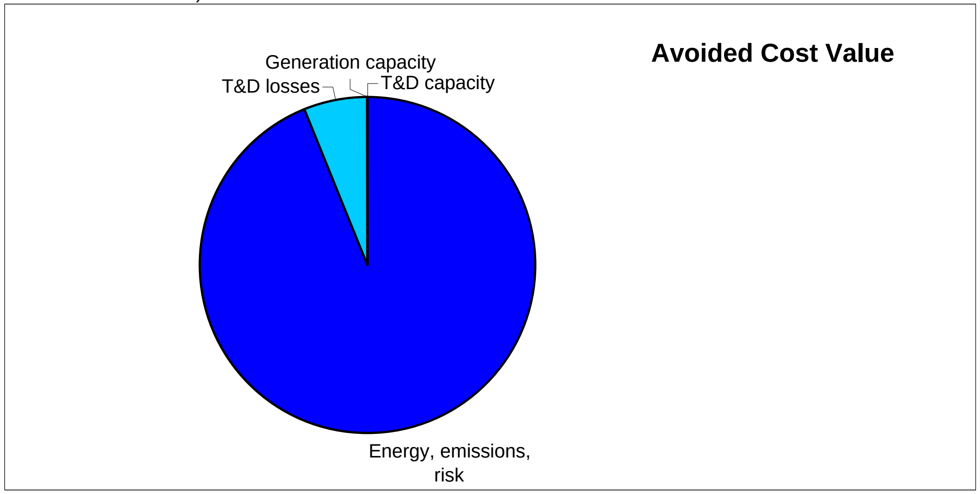
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.836	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.054	PV of avoided cost of energy (T&D losses)	6%
$ 372.36	$ -	PV of avoided cost of generation capacity	0%
$ 92.43	$ -	PV of avoided cost of T&D capacity	0%
	$0.890		100%
			100% Total energy

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		0% Total capacity
7.41%	Discount rate	$0.0747	Levelized cost/kWh of four energy components of AC
30	Measure life	$0.0000	Levelized cost/kWh of two capacity components of AC
10,699	Annual kWh savings per unit		
0.0019%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0000%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 8,939.80	PV of avoided cost of energy (energy + emissions + risk)
$ 581.09	PV of avoided cost of energy (T&D losses)
$ -	PV of avoided cost of generation capacity
$ -	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 9,520.88	Total Resource Cost test benefits
$ 2,278.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 2,278.00	Total Resource Cost test costs
$7,243	Net TRC $ amount
4.18	**TRC benefit / cost ratio**

Electric furnace vs condensing gas space heat conversion



High efficiency clothes washer (electric DHW, dryer)

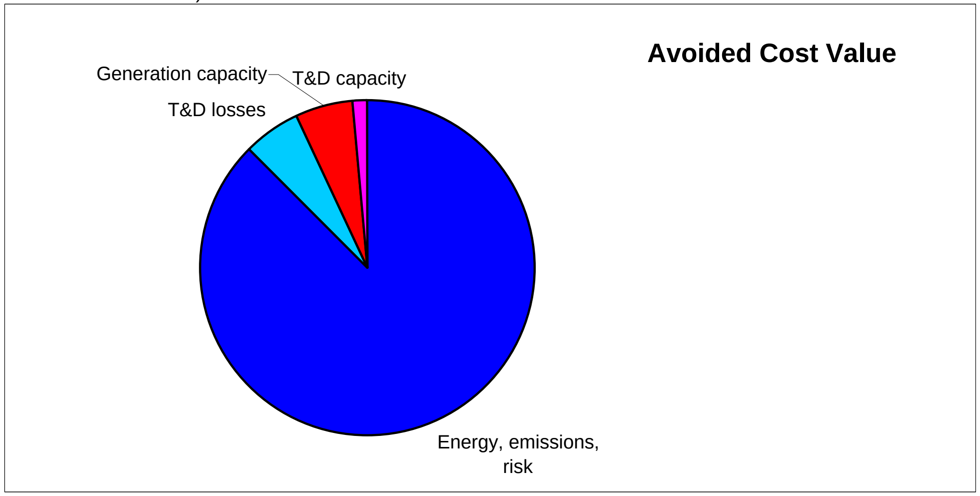
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.478	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.031	PV of avoided cost of energy (T&D losses)	6%
$ 237.24	$ 0.030	PV of avoided cost of generation capacity	6%
$ 57.34	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.547		100%
			93% Total energy
			7% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0597	Levelized cost/kWh of four energy components of AC
14	Measure life	$0.0044	Levelized cost/kWh of two capacity components of AC
381	Annual kWh savings per unit		
0.0155%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0127%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 182.28	PV of avoided cost of energy (energy + emissions + risk)
$ 11.85	PV of avoided cost of energy (T&D losses)
$ 11.51	PV of avoided cost of generation capacity
$ 2.78	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 208.42	Total Resource Cost test benefits
$ 484.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 484.00	Total Resource Cost test costs
($276)	Net TRC $ amount
0.43	**TRC benefit / cost ratio**

High efficiency clothes washer (electric DHW, dryer)



Home electronics and office equipment

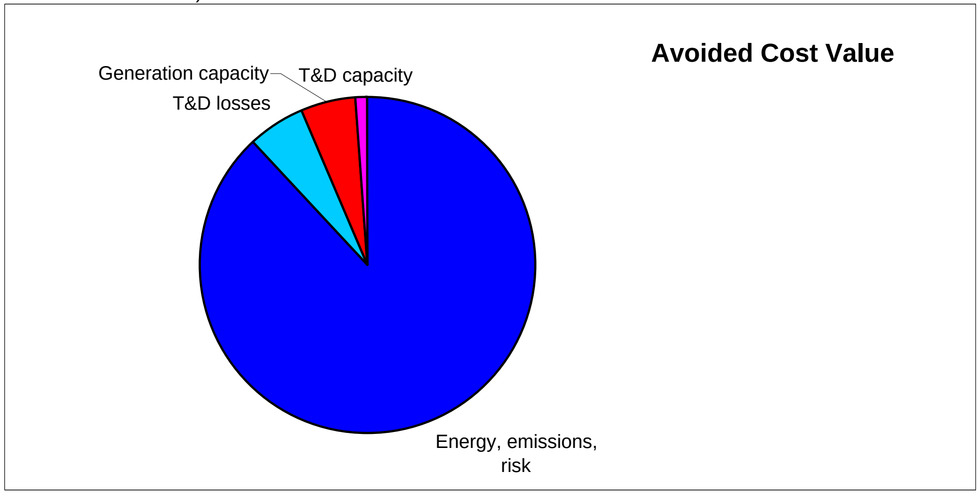
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.496	PV of avoided cost of energy (energy + emissions + risk)	88%	
	$0.032	PV of avoided cost of energy (T&D losses)	6%	
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%	
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%	
	$0.564		100%	
			94%	Total energy
			6%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0595	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0040	Levelized cost/kWh of two capacity components of AC
677	Annual kWh savings per unit		
0.0125%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0114%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 335.87	PV of avoided cost of energy (energy + emissions + risk)
$ 21.83	PV of avoided cost of energy (T&D losses)
$ 19.20	PV of avoided cost of generation capacity
$ 4.65	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 381.55	Total Resource Cost test benefits
$ -	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ -	Total Resource Cost test costs
$382	Net TRC $ amount
no cost	**TRC benefit / cost ratio**

Home electronics and office equipment



Hot tub and swimming pool covers

Summarization of AC benefits and comparison to TRC costs

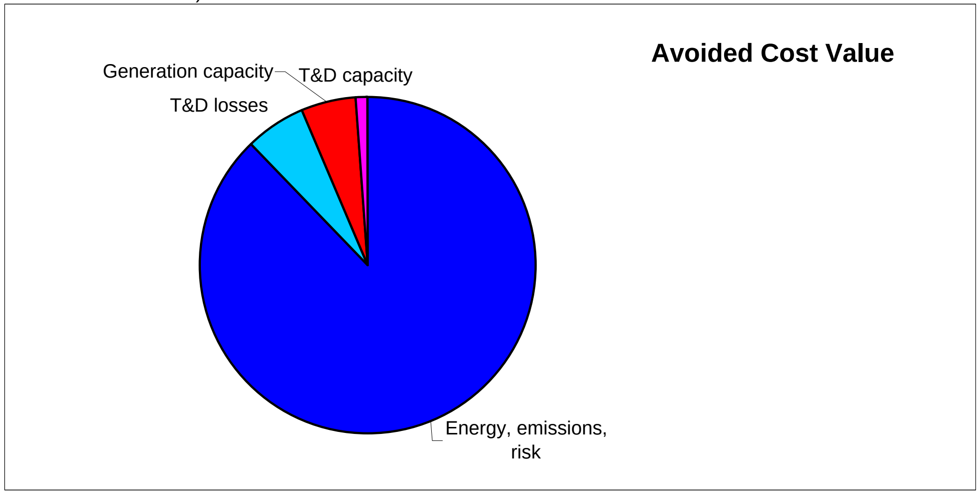
Per first year kW	Per first year kWh		% of total value
	$0.295	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.019	PV of avoided cost of energy (T&D losses)	6%
$ 154.14	$ 0.018	PV of avoided cost of generation capacity	5%
$ 36.80	$ 0.004	PV of avoided cost of T&D capacity	1%
	$0.336		100%
			94% Total energy
			6% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
8	Measure life
250	Annual kWh savings per unit
0.0125%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0114%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0534	Levelized cost/kWh of four energy components of AC
$0.0037	Levelized cost/kWh of two capacity components of AC

$ 73.66	PV of avoided cost of energy (energy + emissions + risk)
$ 4.79	PV of avoided cost of energy (T&D losses)
$ 4.39	PV of avoided cost of generation capacity
$ 1.05	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 83.89	Total Resource Cost test benefits
$ 300.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 300.00	Total Resource Cost test costs
($216)	Net TRC $ amount
0.28	**TRC benefit / cost ratio**

Hot tub ~~and swimming pool~~ covers



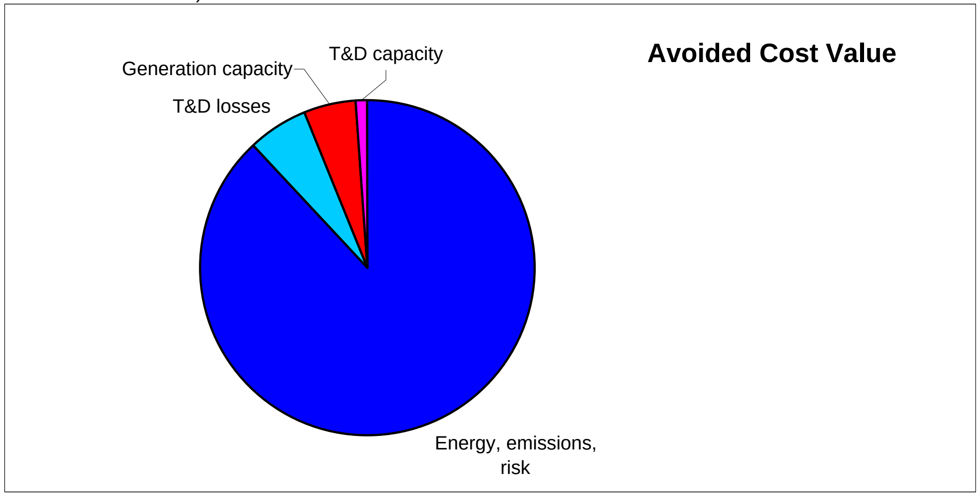
Heat pump water heater (single and multi-family)

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.368	PV of avoided cost of energy (energy + emissions + risk)	88%	
	$0.024	PV of avoided cost of energy (T&D losses)	6%	
$ 184.47	$ 0.021	PV of avoided cost of generation capacity	5%	
$ 44.23	$ 0.005	PV of avoided cost of T&D capacity	1%	
	$0.418		100%	
			94%	Total energy
non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		6%	Total capacity
7.41%	Discount rate		$0.0568	Levelized cost/kWh of four energy components of AC
10	Measure life		$0.0038	Levelized cost/kWh of two capacity components of AC
1,766	Annual kWh savings per unit			
0.0160%	Percent of annual energy in maximum hour (use for "driver" measures)			
0.0113%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)			

$ 649.43	PV of avoided cost of energy (energy + emissions + risk)
$ 42.21	PV of avoided cost of energy (T&D losses)
$ 36.95	PV of avoided cost of generation capacity
$ 8.86	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 737.46	Total Resource Cost test benefits
$ 1,661.96	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 1,661.96	Total Resource Cost test costs
($925)	Net TRC $ amount
0.44	**TRC benefit / cost ratio**

Heat pump water heater (single and multi-family)



Proper HVAC sizing

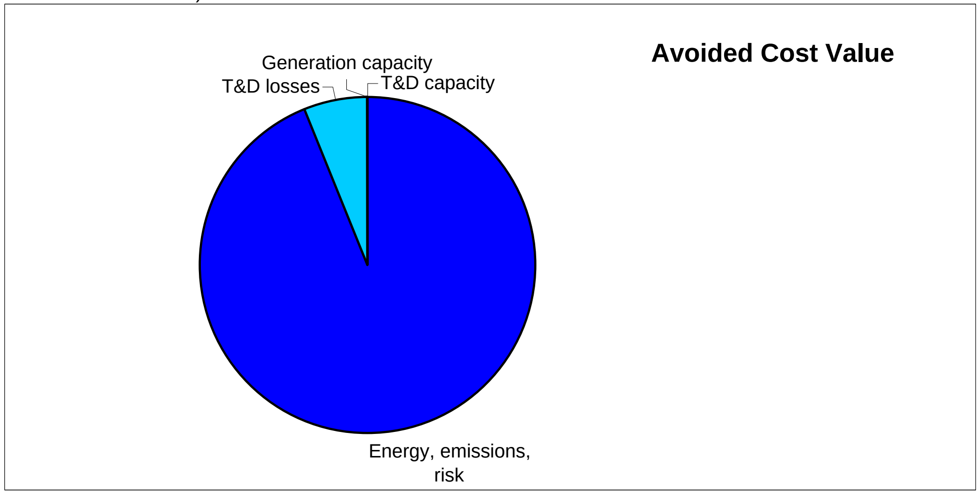
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.595	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.039	PV of avoided cost of energy (T&D losses)	6%
$ 281.00	$ -	PV of avoided cost of generation capacity	0%
$ 68.42	$ -	PV of avoided cost of T&D capacity	0%
	$0.633		100%
			100% Total energy
			0% Total capacity

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0648	Levelized cost/kWh of four energy components of AC
18	Measure life	$0.0000	Levelized cost/kWh of two capacity components of AC
705	Annual kWh savings per unit		
0.0019%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0000%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 419.19	PV of avoided cost of energy (energy + emissions + risk)
$ 27.25	PV of avoided cost of energy (T&D losses)
$ -	PV of avoided cost of generation capacity
$ -	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 446.44	Total Resource Cost test benefits
$ -	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ -	Total Resource Cost test costs
$446	Net TRC $ amount
#DIV/0!	**TRC benefit / cost ratio**

Proper HVAC sizing



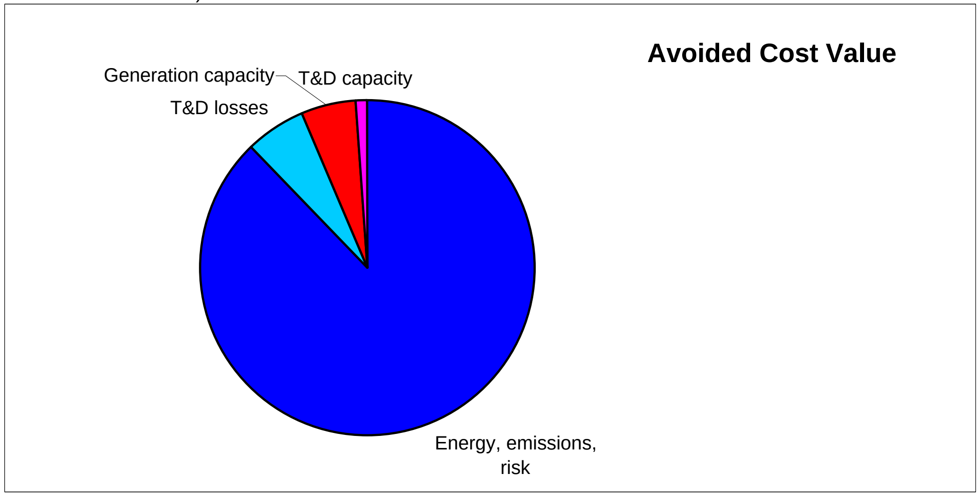
Induction cooktop

Summarization of AC benefits and comparison to TRC costs

Per first year kW		Per first year kWh		% of total value	
		$0.356	PV of avoided cost of energy (energy + emissions + risk)	88%	
		$0.023	PV of avoided cost of energy (T&D losses)	6%	
$ 184.47	$	0.021	PV of avoided cost of generation capacity	5%	
$ 44.23	$	0.005	PV of avoided cost of T&D capacity	1%	
		$0.405		100%	
				94%	Total energy
non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)			6%	Total capacity
7.41%	Discount rate			$0.0550	Levelized cost/kWh of four energy components of AC
10	Measure life			$0.0038	Levelized cost/kWh of two capacity components of AC
27	Annual kWh savings per unit				
0.0125%	Percent of annual energy in maximum hour (use for "driver" measures)				
0.0114%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)				

$	9.60	PV of avoided cost of energy (energy + emissions + risk)
$	0.62	PV of avoided cost of energy (T&D losses)
$	0.57	PV of avoided cost of generation capacity
$	0.14	PV of avoided cost of T&D capacity
$	-	PV of avoided cost of natural gas
$	-	PV of non-energy benefits
$	10.93	Total Resource Cost test benefits
$	264.42	Incremental customer cost
$	-	Incremental non-incentive utility cost
$	264.42	Total Resource Cost test costs
	($253)	Net TRC $ amount
	0.04	**TRC benefit / cost ratio**

Induction cooktop



Insulation (R19-R38, single family, resistance)

Summarization of AC benefits and comparison to TRC costs

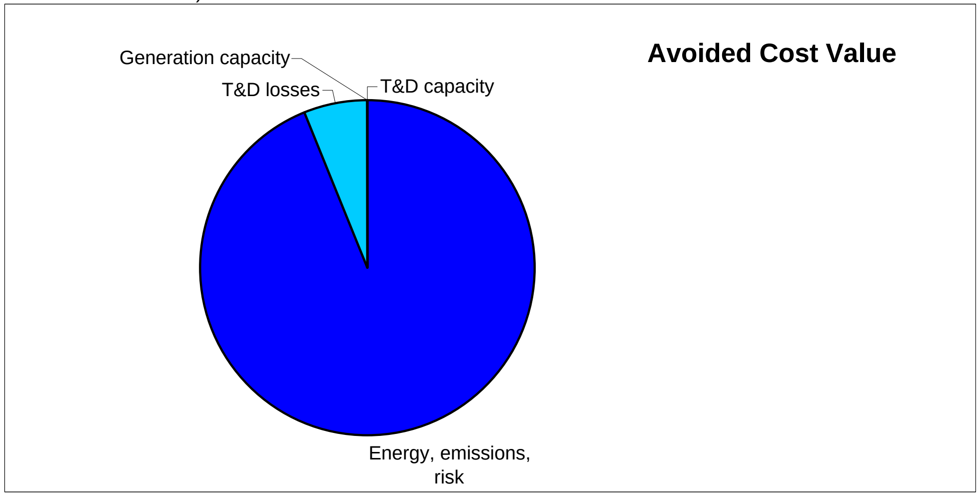
Per first year kW	Per first year kWh		% of total value
	$0.836	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.054	PV of avoided cost of energy (T&D losses)	6%
$ 372.36	$ -	PV of avoided cost of generation capacity	0%
$ 92.43	$ -	PV of avoided cost of T&D capacity	0%
	$0.890		100%
		Total energy	100%
		Total capacity	0%

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
30	Measure life
1,074	Annual kWh savings per unit
0.0019%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0000%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0747	Levelized cost/kWh of four energy components of AC
$0.0000	Levelized cost/kWh of two capacity components of AC

$ 897.41	PV of avoided cost of energy (energy + emissions + risk)
$ 58.33	PV of avoided cost of energy (T&D losses)
$ -	PV of avoided cost of generation capacity
$ -	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 955.74	Total Resource Cost test benefits
$ 812.70	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 812.70	Total Resource Cost test costs
$143	Net TRC $ amount
1.18	**TRC benefit / cost ratio**

Insulation (R19-R38, single family, resistance)



Low flow showerhead

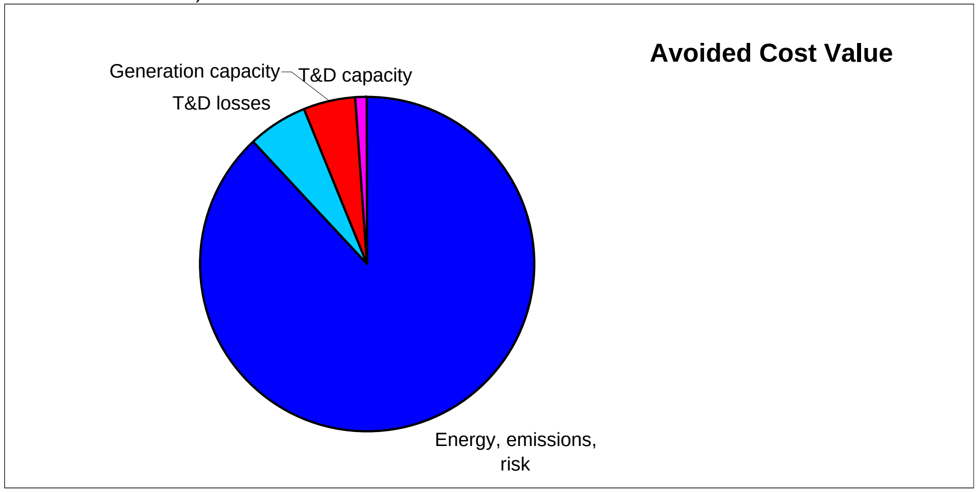
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.368	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.024	PV of avoided cost of energy (T&D losses)	6%
$ 184.47	$ 0.021	PV of avoided cost of generation capacity	5%
$ 44.23	$ 0.005	PV of avoided cost of T&D capacity	1%
	$0.418		100%
			94% Total energy
			6% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0568	Levelized cost/kWh of four energy components of AC
10	Measure life	$0.0038	Levelized cost/kWh of two capacity components of AC
101	Annual kWh savings per unit		
0.0160%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0113%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 37.14	PV of avoided cost of energy (energy + emissions + risk)
$ 2.41	PV of avoided cost of energy (T&D losses)
$ 2.11	PV of avoided cost of generation capacity
$ 0.51	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 42.18	Total Resource Cost test benefits
$ 37.95	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 37.95	Total Resource Cost test costs
$4	Net TRC $ amount
1.11	**TRC benefit / cost ratio**

Low flow showerhead



Pipe insulation (single family, per foot installed)

Summarization of AC benefits and comparison to TRC costs

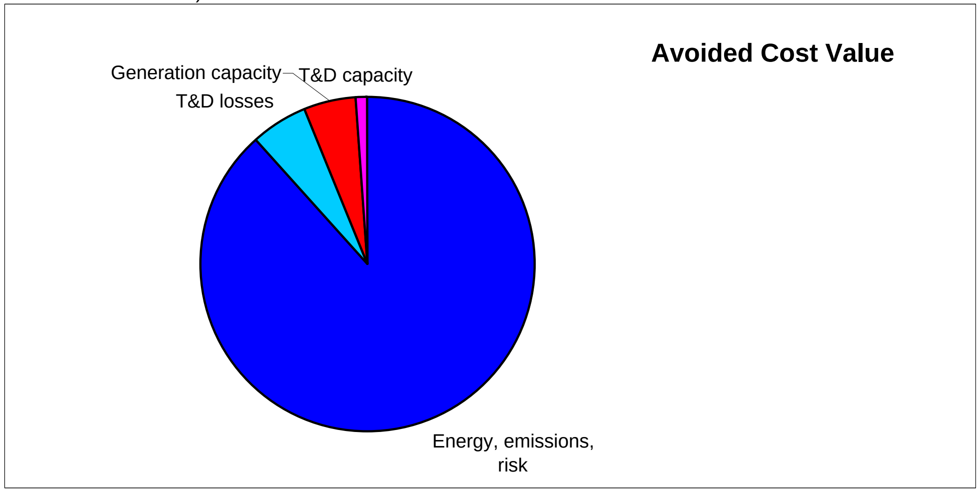
Per first year kW	Per first year kWh		% of total value
	$0.513	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.581		100%
			94% Total energy
			6% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
15	Measure life
133	Annual kWh savings per unit
0.0160%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0113%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0615	Levelized cost/kWh of four energy components of AC
$0.0040	Levelized cost/kWh of two capacity components of AC

$ 68.18	PV of avoided cost of energy (energy + emissions + risk)
$ 4.43	PV of avoided cost of energy (T&D losses)
$ 3.76	PV of avoided cost of generation capacity
$ 0.91	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 77.28	Total Resource Cost test benefits
$ 2.81	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 2.81	Total Resource Cost test costs
$74	Net TRC $ amount
27.50	**TRC benefit / cost ratio**

Pipe insulation (single family, per foot installed)



Smart programmable thermostats

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.431	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.028	PV of avoided cost of energy (T&D losses)	6%
$ 212.09	$ -	PV of avoided cost of generation capacity	0%
$ 51.06	$ -	PV of avoided cost of T&D capacity	0%
	$0.460		100%

100% Total energy

0% Total capacity

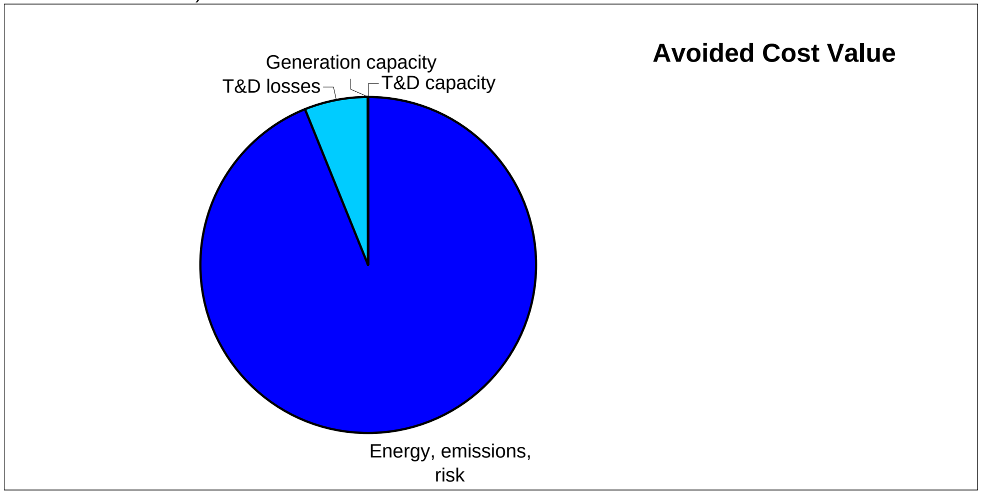
zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
12	Measure life
755	Annual kWh savings per unit
0.0019%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0000%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0591 Levelized cost/kWh of four energy components of AC

$0.0000 Levelized cost/kWh of two capacity components of AC

$ 325.78	PV of avoided cost of energy (energy + emissions + risk)
$ 21.18	PV of avoided cost of energy (T&D losses)
$ -	PV of avoided cost of generation capacity
$ -	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 346.95	Total Resource Cost test benefits
$ 100.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 100.00	Total Resource Cost test costs
$247	Net TRC $ amount
3.47	**TRC benefit / cost ratio**

Smart programmable thermostats



CFL 20W screw-in for incandescent 75W

Summarization of AC benefits and comparison to TRC costs

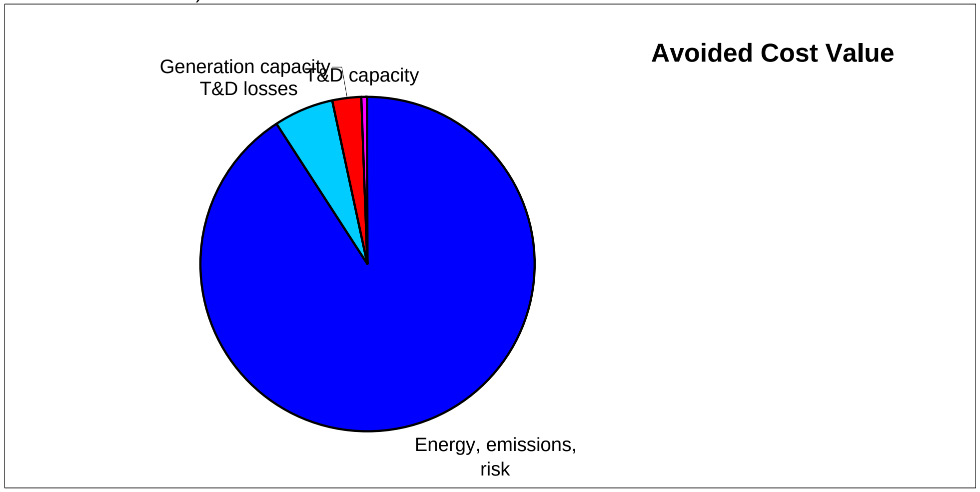
Per first year kW	Per first year kWh		% of total value
	$0.332	PV of avoided cost of energy (energy + emissions + risk)	91%
	$0.022	PV of avoided cost of energy (T&D losses)	6%
$ 169.66	$ 0.010	PV of avoided cost of generation capacity	3%
$ 40.59	$ 0.002	PV of avoided cost of T&D capacity	1%
	$0.366		100%
			97% Total energy
			3% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
9.4	Measure life
42	Annual kWh savings per unit
0.0127%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0059%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0535	Levelized cost/kWh of four energy components of AC
$0.0019	Levelized cost/kWh of two capacity components of AC

$ 13.94	PV of avoided cost of energy (energy + emissions + risk)
$ 0.91	PV of avoided cost of energy (T&D losses)
$ 0.42	PV of avoided cost of generation capacity
$ 0.10	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 15.37	Total Resource Cost test benefits
$ 6.47	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 6.47	Total Resource Cost test costs
$9	Net TRC $ amount
2.38	**TRC benefit / cost ratio**

CFL 20W screw-in for incandescent 75W



Remove second refrigerator

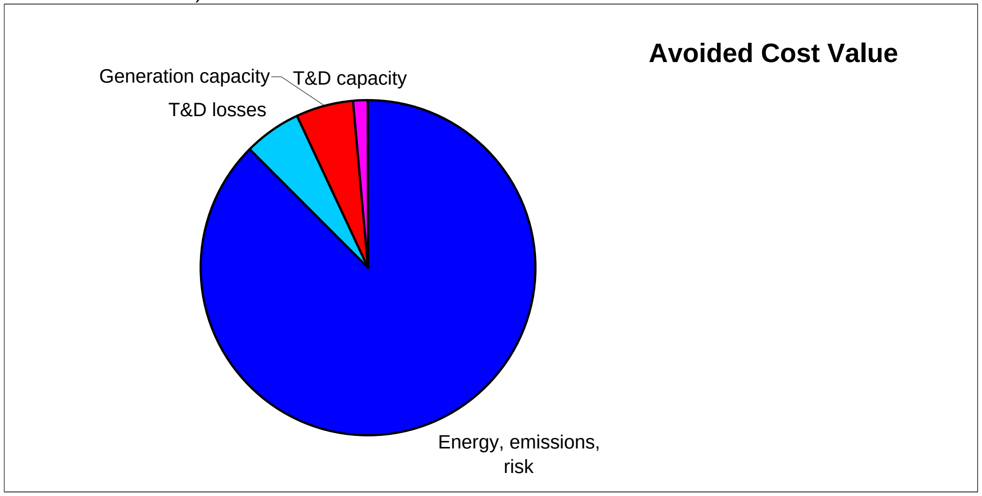
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.615	PV of avoided cost of energy (energy + emissions + risk)	87%	
	$0.040	PV of avoided cost of energy (T&D losses)	6%	
$ 300.00	$ 0.039	PV of avoided cost of generation capacity	6%	
$ 73.31	$ 0.009	PV of avoided cost of T&D capacity	1%	
	$0.704		100%	
			93%	Total energy
			7%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0638	Levelized cost/kWh of four energy components of AC
20	Measure life	$0.0047	Levelized cost/kWh of two capacity components of AC
1,946	Annual kWh savings per unit		
0.0148%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0129%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 1,197.54	PV of avoided cost of energy (energy + emissions + risk)
$ 77.84	PV of avoided cost of energy (T&D losses)
$ 75.31	PV of avoided cost of generation capacity
$ 18.40	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 1,369.10	Total Resource Cost test benefits
$ -	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ -	Total Resource Cost test costs
$1,369	Net TRC $ amount
#DIV/0!	**TRC benefit / cost ratio**

Remove second refrigerator



Energy efficient windows (retrofit, single family, resistance)

Summarization of AC benefits and comparison to TRC costs

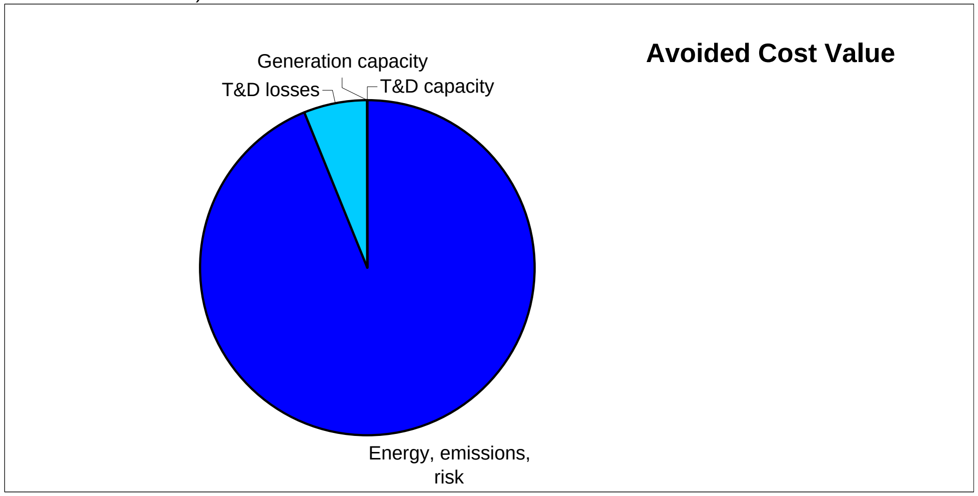
Per first year kW	Per first year kWh		% of total value
	$0.836	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.054	PV of avoided cost of energy (T&D losses)	6%
$ 372.36	$ -	PV of avoided cost of generation capacity	0%
$ 92.43	$ -	PV of avoided cost of T&D capacity	0%
	$0.890		100%
			100% Total energy
			0% Total capacity

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
30	Measure life
2,127	Annual kWh savings per unit
0.0019%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0000%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0747	Levelized cost/kWh of four energy components of AC
$0.0000	Levelized cost/kWh of two capacity components of AC

$ 1,777.26	PV of avoided cost of energy (energy + emissions + risk)
$ 115.52	PV of avoided cost of energy (T&D losses)
$ -	PV of avoided cost of generation capacity
$ -	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 1,892.79	Total Resource Cost test benefits
$ 3,100.69	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 3,100.69	Total Resource Cost test costs
($1,208)	Net TRC $ amount
0.61	**TRC benefit / cost ratio**

Energy efficient windows (retrofit, single family, resistance)



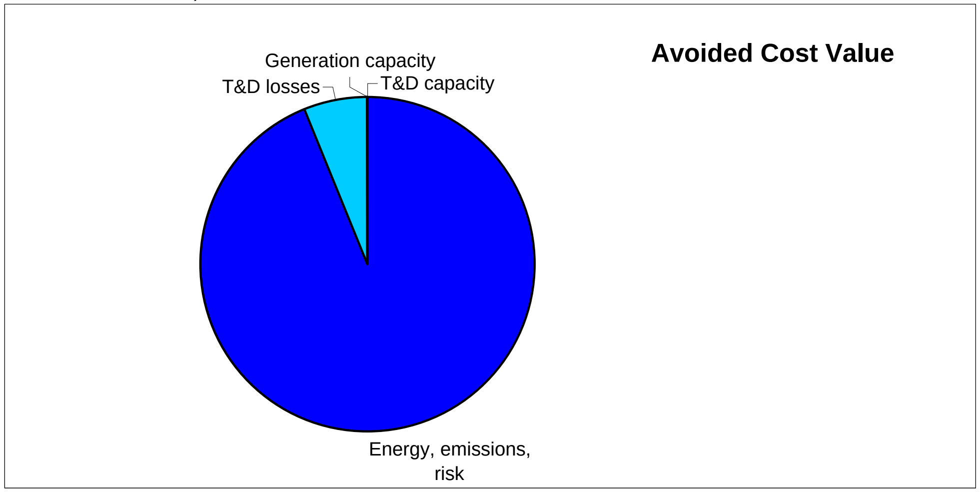
Electric furnace vs heat pump conversion

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.595	PV of avoided cost of energy (energy + emissions + risk)	94%	
	$0.039	PV of avoided cost of energy (T&D losses)	6%	
$ 281.00	$ -	PV of avoided cost of generation capacity	0%	
$ 68.42	$ -	PV of avoided cost of T&D capacity	0%	
	$0.633		100%	
			100%	Total energy
zero		"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)	0%	Total capacity
7.41%		Discount rate	$0.0648	Levelized cost/kWh of four energy components of AC
18		Measure life	$0.0000	Levelized cost/kWh of two capacity components of AC
5,538		Annual kWh savings per unit		
0.0019%		Percent of annual energy in maximum hour (use for "driver" measures)		
0.0000%		Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 3,292.86	PV of avoided cost of energy (energy + emissions + risk)
$ 214.04	PV of avoided cost of energy (T&D losses)
$ -	PV of avoided cost of generation capacity
$ -	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 3,506.90	Total Resource Cost test benefits
$ 1,395.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 1,395.00	Total Resource Cost test costs
$2,112	Net TRC $ amount
2.51	**TRC benefit / cost ratio**

Electric furnace vs heat pump conversion



Smart/energy efficient appliance rebate program

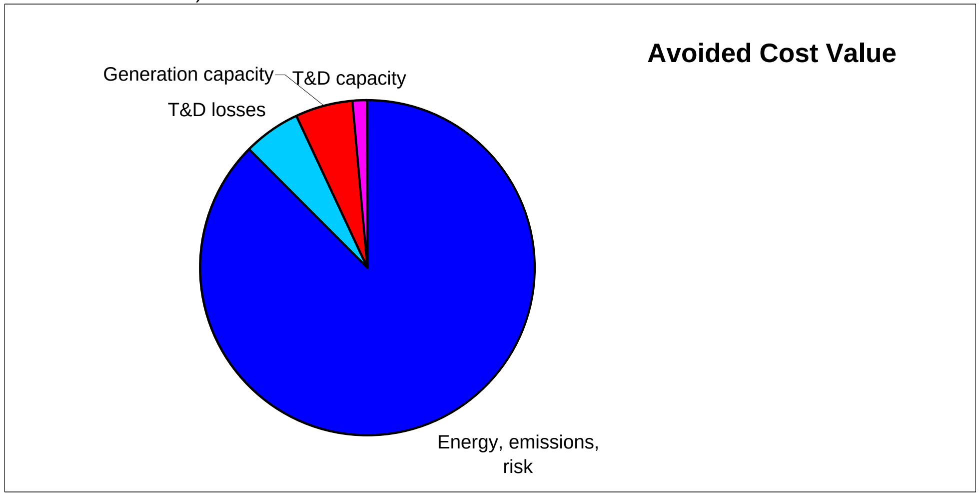
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.570	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.037	PV of avoided cost of energy (T&D losses)	6%
$ 281.00	$ 0.036	PV of avoided cost of generation capacity	6%
$ 68.42	$ 0.009	PV of avoided cost of T&D capacity	1%
	$0.652		100%
			93% Total energy
			7% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0621	Levelized cost/kWh of four energy components of AC
18	Measure life	$0.0046	Levelized cost/kWh of two capacity components of AC
58	Annual kWh savings per unit		
0.0148%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0129%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 33.05	PV of avoided cost of energy (energy + emissions + risk)
$ 2.15	PV of avoided cost of energy (T&D losses)
$ 2.10	PV of avoided cost of generation capacity
$ 0.51	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 37.81	Total Resource Cost test benefits
$ 201.55	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 201.55	Total Resource Cost test costs
($164)	Net TRC $ amount
0.19	**TRC benefit / cost ratio**

Smart/energy efficient appliance rebate program



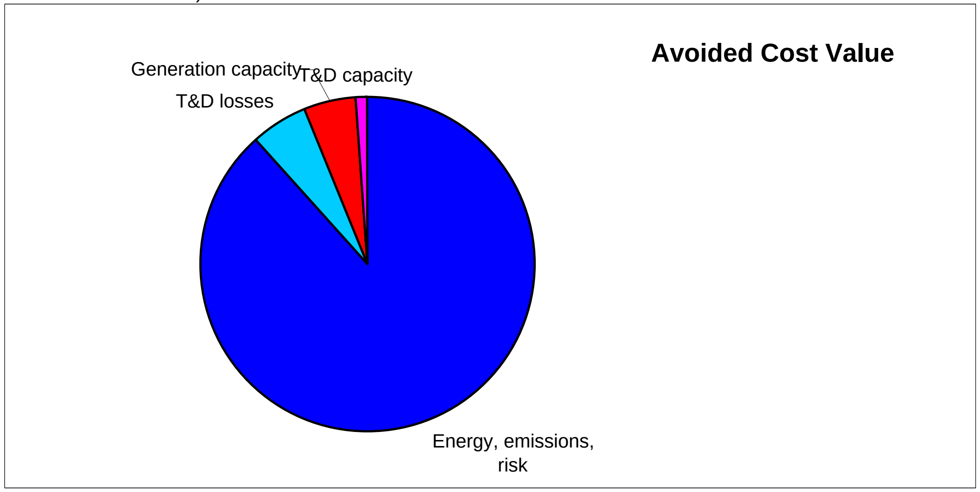
Solar water heating

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.513	PV of avoided cost of energy (energy + emissions + risk)	88%	
	$0.033	PV of avoided cost of energy (T&D losses)	6%	
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%	
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%	
	$0.581		100%	
			94%	Total energy
non-driver		"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)	6%	Total capacity
7.41%		Discount rate	$0.0615	Levelized cost/kWh of four energy components of AC
15		Measure life	$0.0040	Levelized cost/kWh of two capacity components of AC
2,566		Annual kWh savings per unit		
0.0160%		Percent of annual energy in maximum hour (use for "driver" measures)		
0.0113%		Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 1,315.38	PV of avoided cost of energy (energy + emissions + risk)
$ 85.50	PV of avoided cost of energy (T&D losses)
$ 72.46	PV of avoided cost of generation capacity
$ 17.55	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 1,490.89	Total Resource Cost test benefits
$ 5,310.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 5,310.00	Total Resource Cost test costs
($3,819)	Net TRC $ amount
0.28	**TRC benefit / cost ratio**

Solar water heating



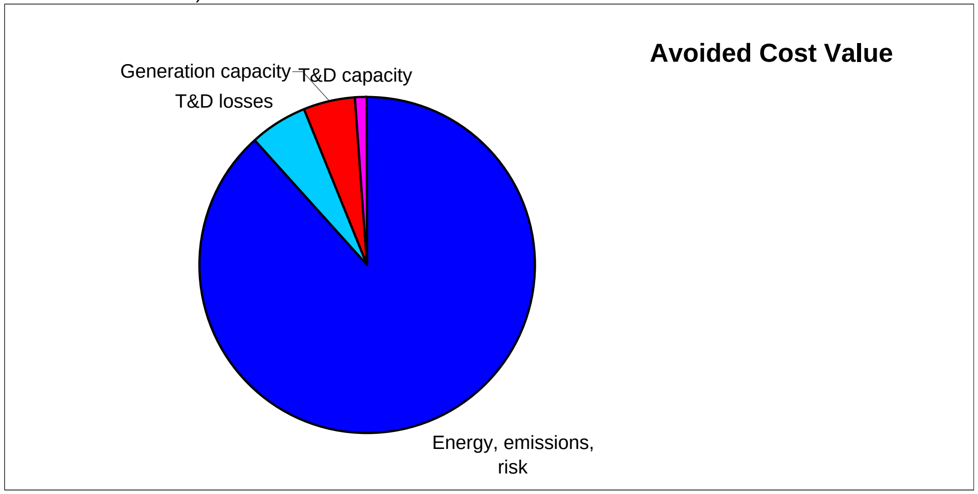
Tankless water heater (single family)

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.513	PV of avoided cost of energy (energy + emissions + risk)	88%	
	$0.033	PV of avoided cost of energy (T&D losses)	6%	
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%	
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%	
	$0.581		100%	
			94%	Total energy
non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		6%	Total capacity
7.41%	Discount rate		$0.0615	Levelized cost/kWh of four energy components of AC
15	Measure life		$0.0040	Levelized cost/kWh of two capacity components of AC
682	Annual kWh savings per unit			
0.0160%	Percent of annual energy in maximum hour (use for "driver" measures)			
0.0113%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)			

$ 349.61	PV of avoided cost of energy (energy + emissions + risk)
$ 22.72	PV of avoided cost of energy (T&D losses)
$ 19.26	PV of avoided cost of generation capacity
$ 4.66	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 396.25	Total Resource Cost test benefits
$ 1,010.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 1,010.00	Total Resource Cost test costs
($614)	Net TRC $ amount
0.39	**TRC benefit / cost ratio**

Tankless water heater (single family)



HE Variable High Speed Motor

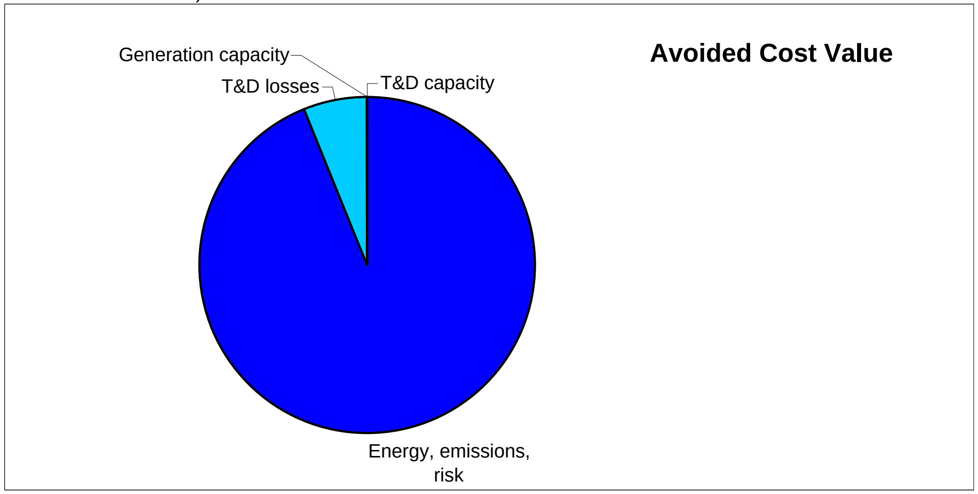
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.642	PV of avoided cost of energy (energy + emissions + risk)	94%	
	$0.042	PV of avoided cost of energy (T&D losses)	6%	
$ 300.00	$ 0.000	PV of avoided cost of generation capacity	0%	
$ 73.31	$ 0.000	PV of avoided cost of T&D capacity	0%	
	$0.684		100%	
			100%	Total energy
			0%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0666	Levelized cost/kWh of four energy components of AC
20	Measure life	$0.0000	Levelized cost/kWh of two capacity components of AC
250	Annual kWh savings per unit		
0.0019%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0000%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 160.42	PV of avoided cost of energy (energy + emissions + risk)
$ 10.43	PV of avoided cost of energy (T&D losses)
$ 0.03	PV of avoided cost of generation capacity
$ 0.01	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 170.89	Total Resource Cost test benefits
$ 200.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 200.00	Total Resource Cost test costs
($29)	Net TRC $ amount
0.85	**TRC benefit / cost ratio**

HE Variable High Speed Motor



Water heater controller

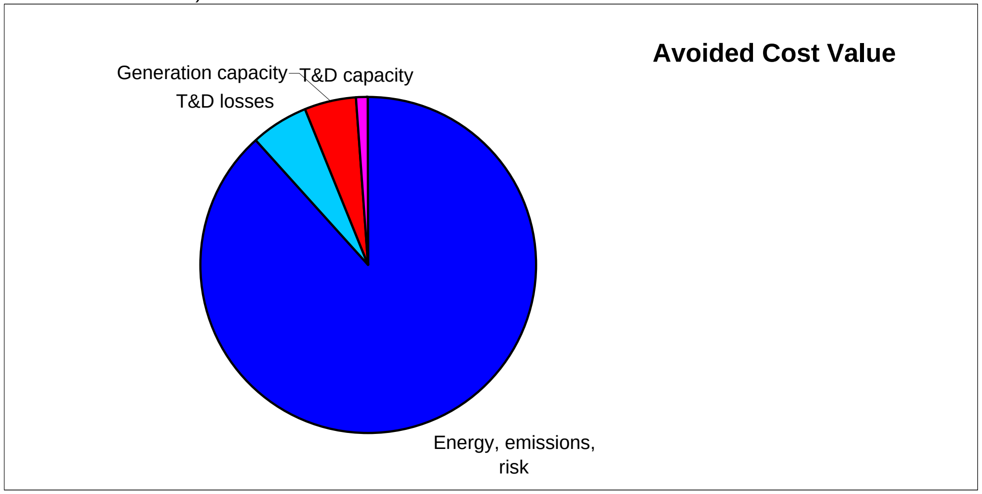
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.513	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.581		100%
			94% Total energy
			6% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0615	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0040	Levelized cost/kWh of two capacity components of AC
224	Annual kWh savings per unit		
0.0160%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0113%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$ 114.83	PV of avoided cost of energy (energy + emissions + risk)
$ 7.46	PV of avoided cost of energy (T&D losses)
$ 6.33	PV of avoided cost of generation capacity
$ 1.53	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 130.15	Total Resource Cost test benefits
$ 15.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 15.00	Total Resource Cost test costs
$115	Net TRC $ amount
8.68	**TRC benefit / cost ratio**

Water heater controller



Water heater tank wraps, pads, closet insulation

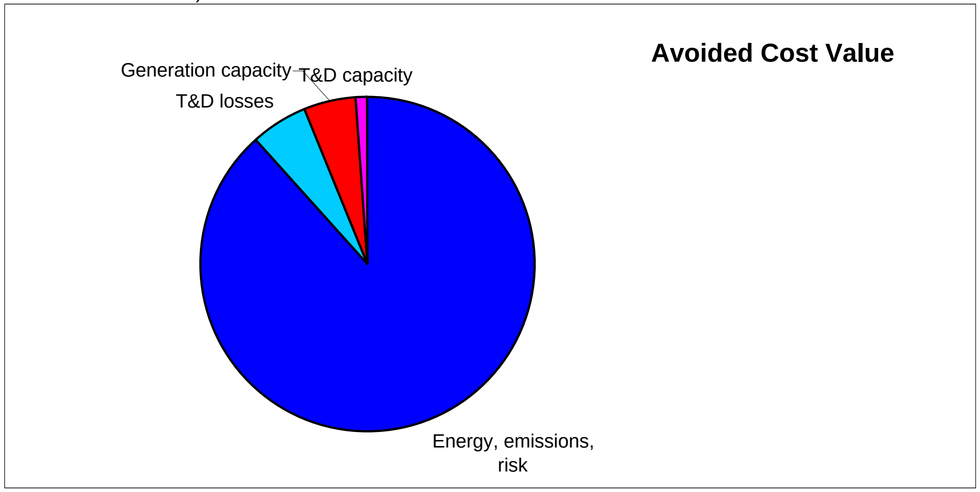
Summarization of AC benefits and comparison to TRC costs

Per first year kW		Per first year kWh			% of total value	
			$0.513	PV of avoided cost of energy (energy + emissions + risk)	88%	
			$0.033	PV of avoided cost of energy (T&D losses)	6%	
$	248.96	$	0.028	PV of avoided cost of generation capacity	5%	
$	60.28	$	0.007	PV of avoided cost of T&D capacity	1%	
			$0.581		100%	
					94%	Total energy

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)	6%	Total capacity
7.41%	Discount rate	$0.0615	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0040	Levelized cost/kWh of two capacity components of AC
364	Annual kWh savings per unit		
0.0160%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0113%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$	186.59	PV of avoided cost of energy (energy + emissions + risk)
$	12.13	PV of avoided cost of energy (T&D losses)
$	10.28	PV of avoided cost of generation capacity
$	2.49	PV of avoided cost of T&D capacity
$	-	PV of avoided cost of natural gas
$	-	PV of non-energy benefits
$	211.49	Total Resource Cost test benefits
$	17.00	Incremental customer cost
$	-	Incremental non-incentive utility cost
$	17.00	Total Resource Cost test costs
	$194	Net TRC $ amount
	12.44	**TRC benefit / cost ratio**

Water heater tank wraps, pads, closet insulation



Commercial Measures

Light fixture reconfiguration

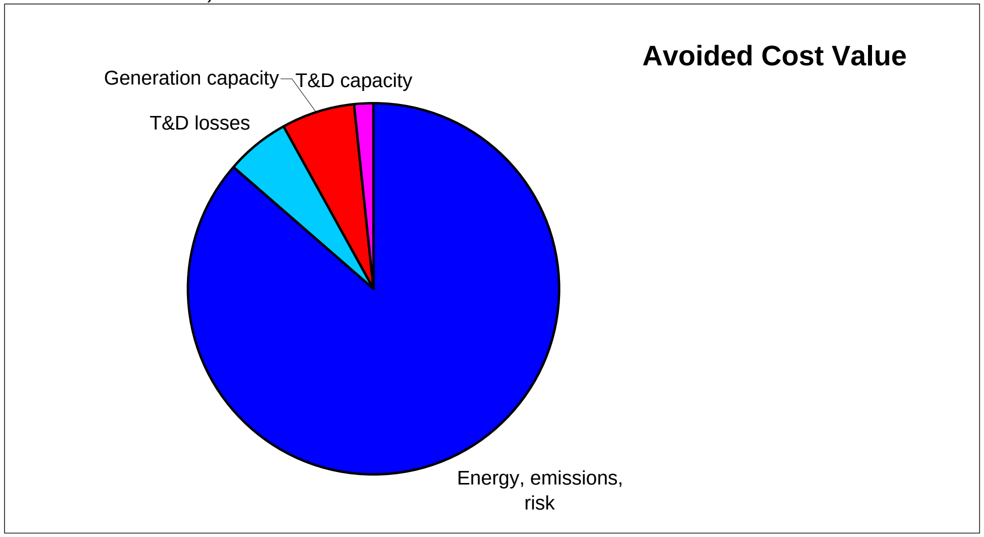
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.535	PV of avoided cost of energy (energy + emissions + risk)	86%
	$0.035	PV of avoided cost of energy (T&D losses)	6%
$ 260.14	$ 0.040	PV of avoided cost of generation capacity	6%
$ 63.11	$ 0.010	PV of avoided cost of T&D capacity	2%
	$0.619		100%
			92% Total energy
			8% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0620	Levelized cost/kWh of four energy components of AC
16	Measure life	$0.0054	Levelized cost/kWh of two capacity components of AC
0.716	Annual kWh savings per unit		
0.0207%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0153%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$0.38	PV of avoided cost of energy (energy + emissions + risk)
$0.02	PV of avoided cost of energy (T&D losses)
$0.03	PV of avoided cost of generation capacity
$0.01	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.44	Total Resource Cost test benefits
$0.50	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.50	Total Resource Cost test costs
($0.06)	Net TRC $ amount
0.89	**TRC benefit / cost ratio**

Light fixture reconfiguration



Energy efficient case fans (grocery, per sq. ft.)

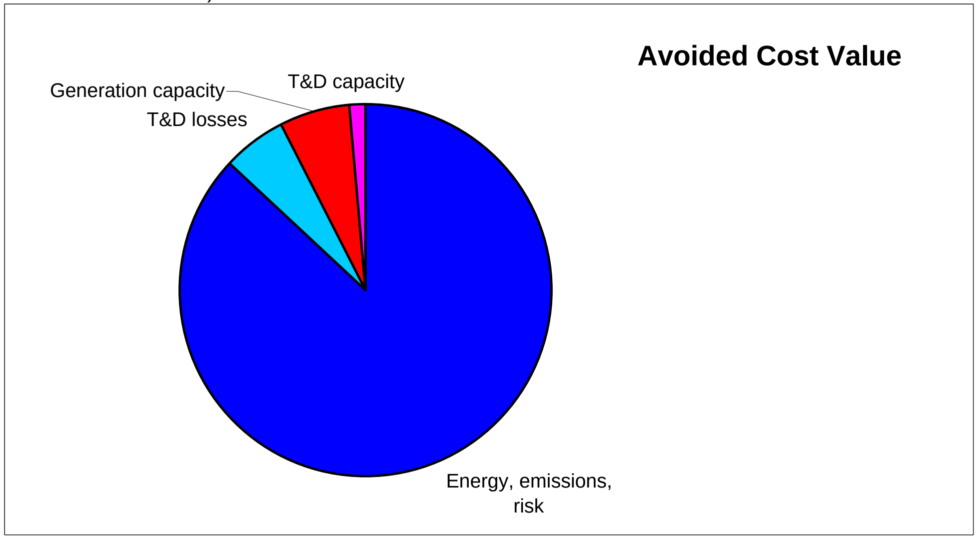
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.522	PV of avoided cost of energy (energy + emissions + risk)	87%	
	$0.034	PV of avoided cost of energy (T&D losses)	6%	
$ 260.14	$ 0.036	PV of avoided cost of generation capacity	6%	
$ 63.11	$ 0.009	PV of avoided cost of T&D capacity	1%	
	$0.601		100%	
			93%	Total energy
			7%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0605	Levelized cost/kWh of four energy components of AC
16	Measure life	$0.0049	Levelized cost/kWh of two capacity components of AC
2.897	Annual kWh savings per unit		
0.0152%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0139%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$1.51	PV of avoided cost of energy (energy + emissions + risk)
$0.10	PV of avoided cost of energy (T&D losses)
$0.10	PV of avoided cost of generation capacity
$0.03	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$1.74	Total Resource Cost test benefits
$1.16	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$1.16	Total Resource Cost test costs
$0.58	Net TRC $ amount
1.50	**TRC benefit / cost ratio**

Energy efficient case fans (grocery, per sq. ft.)



CFL 20W fixture for incandescent 75W (retrofit)

Summarization of AC benefits and comparison to TRC costs

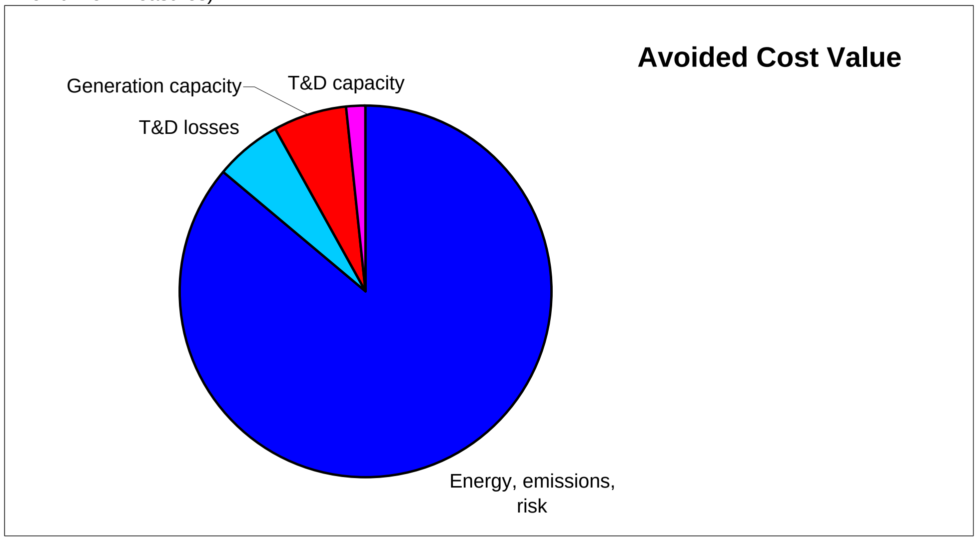
Per first year kW	Per first year kWh		% of total value
	$0.425	PV of avoided cost of energy (energy + emissions + risk)	86%
	$0.028	PV of avoided cost of energy (T&D losses)	6%
$ 212.09	$ 0.032	PV of avoided cost of generation capacity	7%
$ 51.06	$ 0.008	PV of avoided cost of T&D capacity	2%
	$0.493		100%
			92% Total energy
			8% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
12	Measure life
260	Annual kWh savings per unit
0.0207%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0153%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0583	Levelized cost/kWh of four energy components of AC
$0.0052	Levelized cost/kWh of two capacity components of AC

$110.54	PV of avoided cost of energy (energy + emissions + risk)
$7.18	PV of avoided cost of energy (T&D losses)
$8.41	PV of avoided cost of generation capacity
$2.03	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$128.16	Total Resource Cost test benefits
$48.50	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$48.50	Total Resource Cost test costs
$79.66	Net TRC $ amount
2.64	**TRC benefit / cost ratio**

CFL 20W fixture for incandescent 75W (retrofit)



Commissioning/retro-commissioning

Summarization of AC benefits and comparison to TRC costs

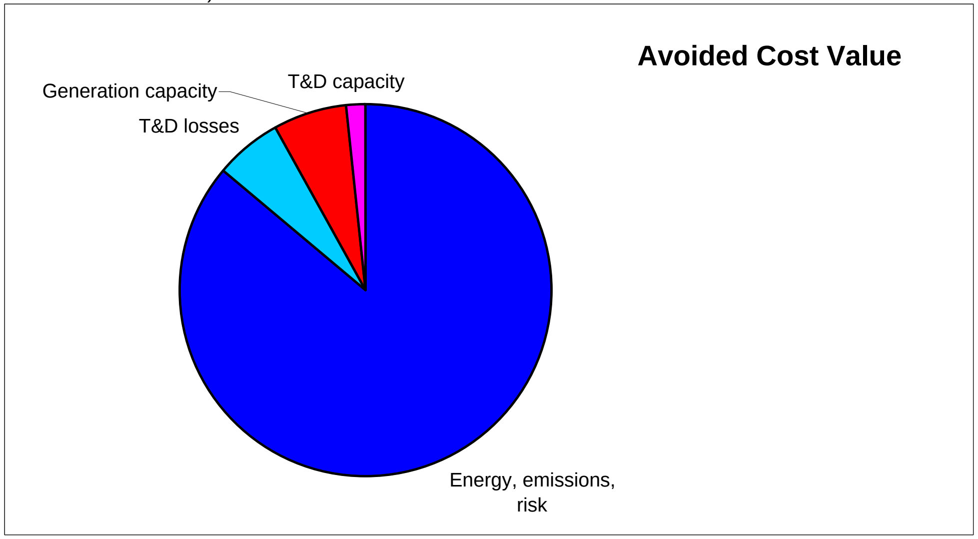
Per first year kW	Per first year kWh		% of total value
	$0.207	PV of avoided cost of energy (energy + emissions + risk)	86%
	$0.013	PV of avoided cost of energy (T&D losses)	6%
$ 102.97	$ 0.016	PV of avoided cost of generation capacity	7%
$ 24.42	$ 0.004	PV of avoided cost of T&D capacity	2%
	$0.240		100%
			92% Total energy
			8% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
5	Measure life
4.000	Annual kWh savings per unit
0.0205%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0154%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0544	Levelized cost/kWh of four energy components of AC
$0.0048	Levelized cost/kWh of two capacity components of AC

$0.83	PV of avoided cost of energy (energy + emissions + risk)
$0.05	PV of avoided cost of energy (T&D losses)
$0.06	PV of avoided cost of generation capacity
$0.02	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.96	Total Resource Cost test benefits
$0.27	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.27	Total Resource Cost test costs
$0.69	Net TRC $ amount
3.56	**TRC benefit / cost ratio**

Commissioning/retro-commissioning



Demand defrost (grocery, per sq. ft.)

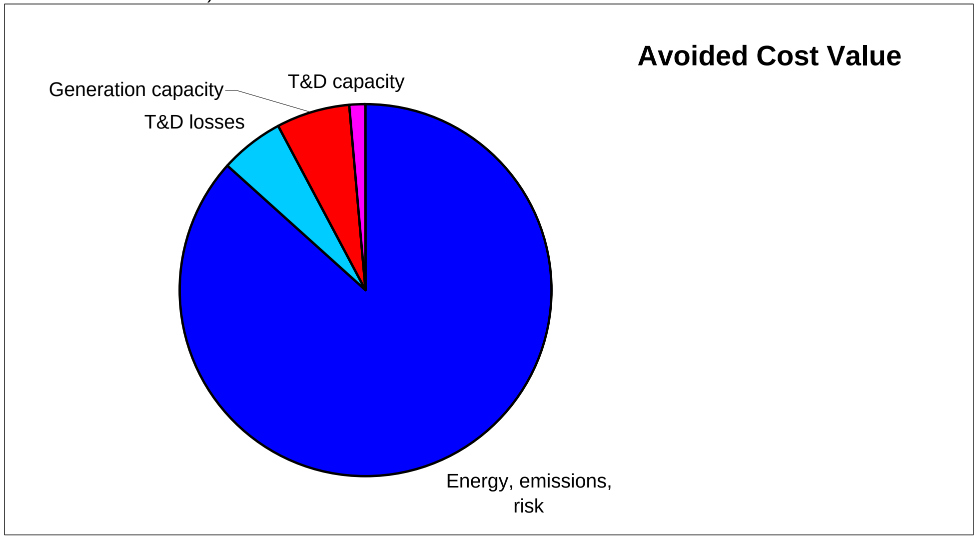
Summarization of AC benefits and comparison to TRC costs

Per first year kW		Per first year kWh			% of total value
			$0.356	PV of avoided cost of energy (energy + emissions + risk)	87%
			$0.023	PV of avoided cost of energy (T&D losses)	6%
$	184.47	$	0.026	PV of avoided cost of generation capacity	6%
$	44.23	$	0.006	PV of avoided cost of T&D capacity	1%
			$0.411		100%
					92% Total energy
					8% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0550	Levelized cost/kWh of four energy components of AC
10	Measure life	$0.0046	Levelized cost/kWh of two capacity components of AC
1.876	Annual kWh savings per unit		
0.0152%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0139%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$0.67	PV of avoided cost of energy (energy + emissions + risk)
$0.04	PV of avoided cost of energy (T&D losses)
$0.05	PV of avoided cost of generation capacity
$0.01	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.77	Total Resource Cost test benefits
$0.04	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.04	Total Resource Cost test costs
$0.73	Net TRC $ amount
19.26	**TRC benefit / cost ratio**

Demand defrost (grocery, per sq. ft.)



Energy efficient ice makers (grocery)

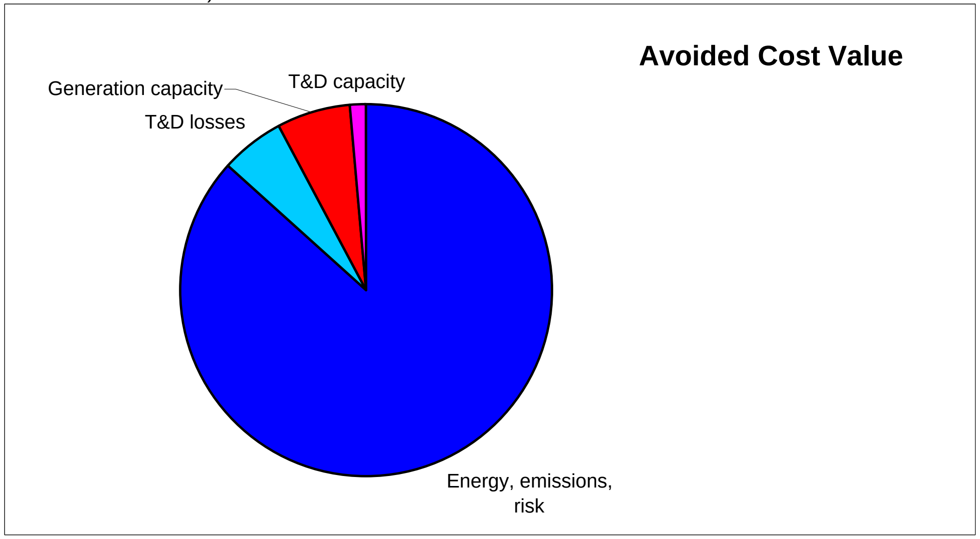
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh			% of total value	
		$0.356	PV of avoided cost of energy (energy + emissions + risk)	87%	
		$0.023	PV of avoided cost of energy (T&D losses)	6%	
$ 184.47	$	0.026	PV of avoided cost of generation capacity	6%	
$ 44.23	$	0.006	PV of avoided cost of T&D capacity	1%	
		$0.411		100%	
				92%	Total energy
				8%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0550	Levelized cost/kWh of four energy components of AC
10	Measure life	$0.0046	Levelized cost/kWh of two capacity components of AC
1,639.000	Annual kWh savings per unit		
0.0152%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0139%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$583.20	PV of avoided cost of energy (energy + emissions + risk)
$37.91	PV of avoided cost of energy (T&D losses)
$41.99	PV of avoided cost of generation capacity
$10.07	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$673.16	Total Resource Cost test benefits
$2,507.00	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$2,507.00	Total Resource Cost test costs
($1,833.84)	Net TRC $ amount
0.27	**TRC benefit / cost ratio**

Energy efficient ice makers (grocery)



Exit sign replacement (electroluminescent)

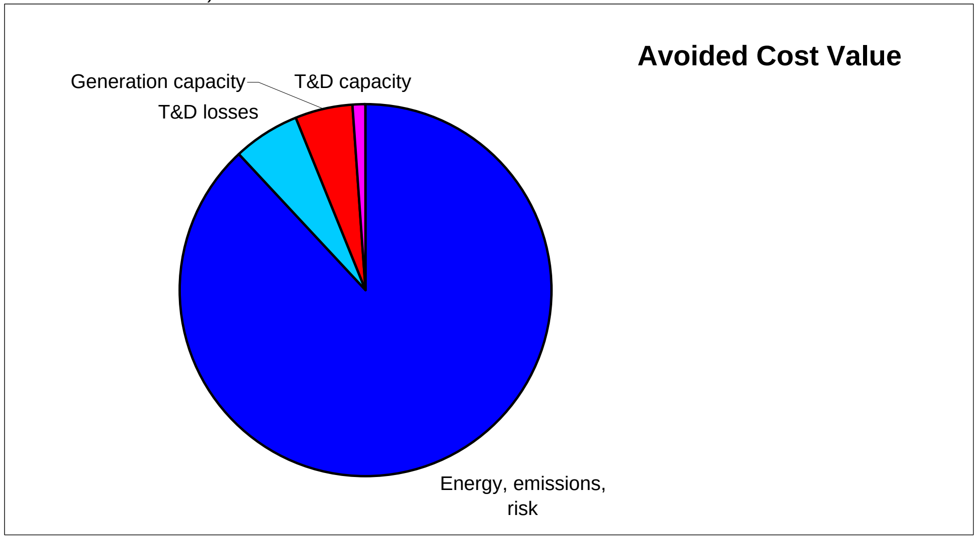
Summarization of AC benefits and comparison to TRC costs

Per first year kW		Per first year kWh			% of total value
			$0.616	PV of avoided cost of energy (energy + emissions + risk)	88%
			$0.040	PV of avoided cost of energy (T&D losses)	6%
$	300.00	$	0.034	PV of avoided cost of generation capacity	5%
$	73.31	$	0.008	PV of avoided cost of T&D capacity	1%
			$0.699		100%

		94%	Total energy
non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)	6%	Total capacity
7.41%	Discount rate	$0.0639	Levelized cost/kWh of four energy components of AC
20	Measure life	$0.0042	Levelized cost/kWh of two capacity components of AC
381.000	Annual kWh savings per unit		
0.0114%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0114%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$234.72	PV of avoided cost of energy (energy + emissions + risk)
$15.26	PV of avoided cost of energy (T&D losses)
$13.05	PV of avoided cost of generation capacity
$3.19	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$266.21	Total Resource Cost test benefits
$107.34	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$107.34	Total Resource Cost test costs
$158.87	Net TRC $ amount
2.48	**TRC benefit / cost ratio**

Exit sign replacement (electroluminescent)



Prescriptive Energy Recovery Ventilation (ERV)

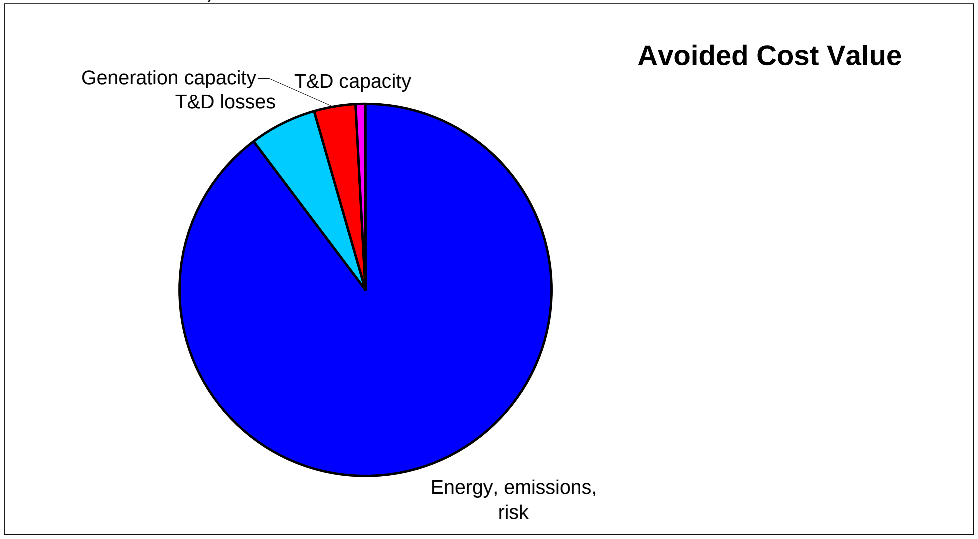
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.506	PV of avoided cost of energy (energy + emissions + risk)	90%	
	$0.033	PV of avoided cost of energy (T&D losses)	6%	
$ 248.96	$ 0.021	PV of avoided cost of generation capacity	4%	
$ 60.28	$ 0.005	PV of avoided cost of T&D capacity	1%	
	$0.564		100%	
			95%	Total energy
			5%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0607	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0029	Levelized cost/kWh of two capacity components of AC
20,000.000	Annual kWh savings per unit		
0.0104%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0082%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$10,119.42	PV of avoided cost of energy (energy + emissions + risk)
$657.76	PV of avoided cost of energy (T&D losses)
$410.54	PV of avoided cost of generation capacity
$99.41	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$11,287.13	Total Resource Cost test benefits
$14,000.00	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$14,000.00	Total Resource Cost test costs
($2,712.87)	Net TRC $ amount
0.81	**TRC benefit / cost ratio**

Prescriptive Energy Recovery Ventilation (ERV)



Evaporator fan cycling (grocery)

Summarization of AC benefits and comparison to TRC costs

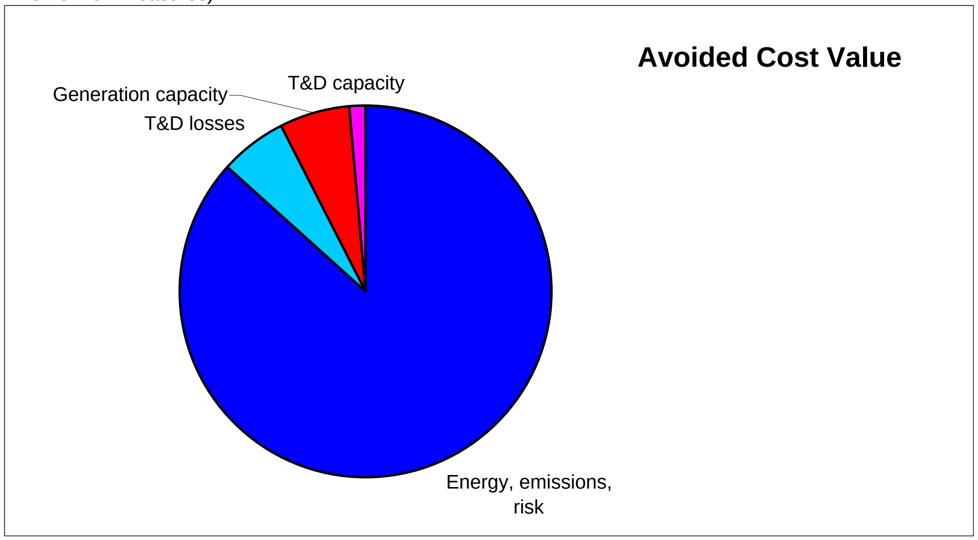
Per first year kW	Per first year kWh		% of total value	
	$0.203	PV of avoided cost of energy (energy + emissions + risk)	87%	
	$0.013	PV of avoided cost of energy (T&D losses)	6%	
$ 102.97	$ 0.014	PV of avoided cost of generation capacity	6%	
$ 24.42	$ 0.003	PV of avoided cost of T&D capacity	1%	
	$0.234		100%	
			92%	Total energy
			8%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
5	Measure life
0.133	Annual kWh savings per unit
0.0152%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0139%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0532	Levelized cost/kWh of four energy components of AC
$0.0044	Levelized cost/kWh of two capacity components of AC

$0.03	PV of avoided cost of energy (energy + emissions + risk)
$0.00	PV of avoided cost of energy (T&D losses)
$0.00	PV of avoided cost of generation capacity
$0.00	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.03	Total Resource Cost test benefits
$0.09	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.09	Total Resource Cost test costs
($0.06)	Net TRC $ amount
0.35	**TRC benefit / cost ratio**

Evaporator fan cycling (grocery)



Fast-acting loading dock doors and seals

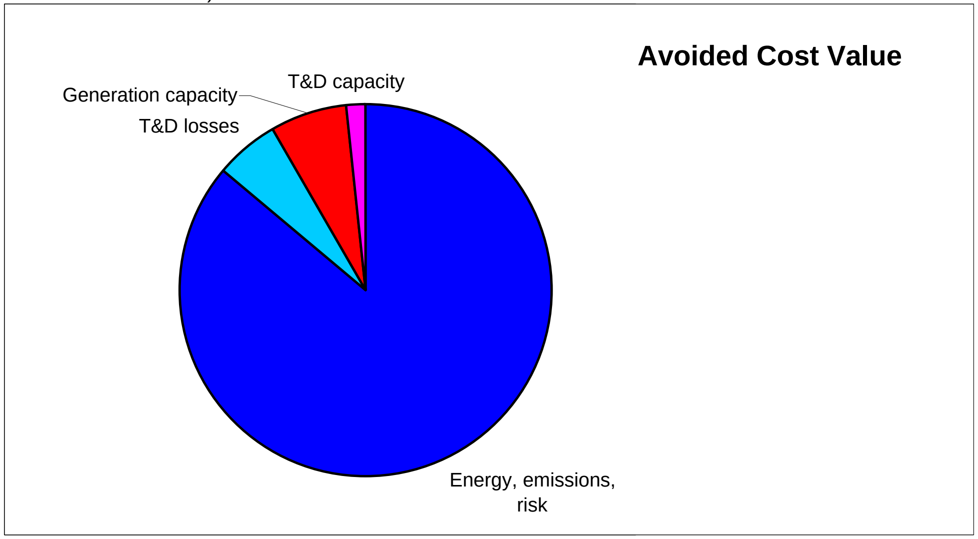
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.423	PV of avoided cost of energy (energy + emissions + risk)	86%	
	$0.027	PV of avoided cost of energy (T&D losses)	6%	
$ 212.09	$ 0.033	PV of avoided cost of generation capacity	7%	
$ 51.06	$ 0.008	PV of avoided cost of T&D capacity	2%	
	$0.491		100%	
			92%	Total energy
			8%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0579	Levelized cost/kWh of four energy components of AC
12	Measure life	$0.0052	Levelized cost/kWh of two capacity components of AC
48,013.000	Annual kWh savings per unit		
0.0205%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0154%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$20,303.84	PV of avoided cost of energy (energy + emissions + risk)
$1,319.75	PV of avoided cost of energy (T&D losses)
$1,568.89	PV of avoided cost of generation capacity
$377.67	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$23,570.15	Total Resource Cost test benefits
$14,197.00	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$14,197.00	Total Resource Cost test costs
$9,373.15	Net TRC $ amount
1.66	**TRC benefit / cost ratio**

Fast-acting loading dock doors and seals



HE Chiller, 0.51 kW/ton, 300 Tons (per sq. ft.)

Summarization of AC benefits and comparison to TRC costs

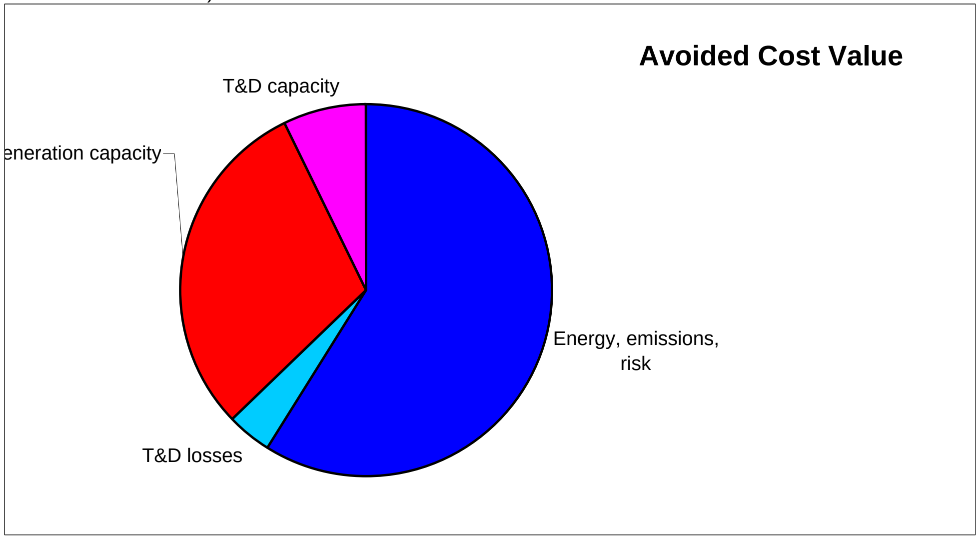
Per first year kW	Per first year kWh		% of total value
	$0.503	PV of avoided cost of energy (energy + emissions + risk)	59%
	$0.033	PV of avoided cost of energy (T&D losses)	4%
$ 248.96	$ 0.257	PV of avoided cost of generation capacity	30%
$ 60.28	$ 0.062	PV of avoided cost of T&D capacity	7%
	$0.854		100%
			63% Total energy
			37% Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
15	Measure life
0.728	Annual kWh savings per unit
0.1031%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0547%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0603	Levelized cost/kWh of four energy components of AC
$0.0359	Levelized cost/kWh of two capacity components of AC

$0.37	PV of avoided cost of energy (energy + emissions + risk)
$0.02	PV of avoided cost of energy (T&D losses)
$0.19	PV of avoided cost of generation capacity
$0.05	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.62	Total Resource Cost test benefits
$0.18	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.18	Total Resource Cost test costs
$0.44	Net TRC $ amount
3.45	**TRC benefit / cost ratio**

HE Chiller, 0.51 kW/ton, 300 Tons (per sq. ft.)



HE DX, 10 tons, EER=11.3 (per sq. ft.)

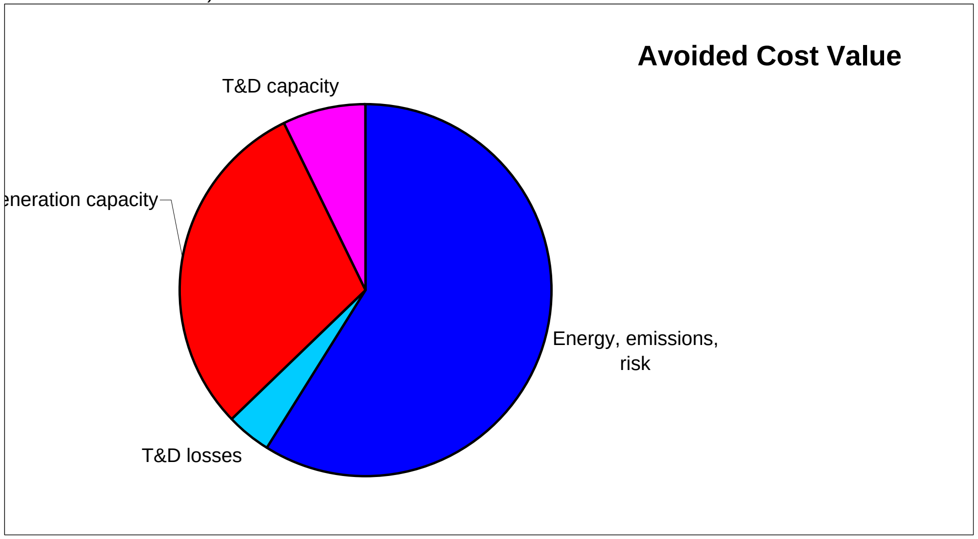
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.503	PV of avoided cost of energy (energy + emissions + risk)	59%
	$0.033	PV of avoided cost of energy (T&D losses)	4%
$ 248.96	$ 0.257	PV of avoided cost of generation capacity	30%
$ 60.28	$ 0.062	PV of avoided cost of T&D capacity	7%
	$0.854		100%
			63% Total energy
			37% Total capacity

$0.0603 Levelized cost/kWh of four energy components of AC
$0.0359 Levelized cost/kWh of two capacity components of AC

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
15	Measure life
0.498	Annual kWh savings per unit
0.1031%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0547%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)
$0.25	PV of avoided cost of energy (energy + emissions + risk)
$0.02	PV of avoided cost of energy (T&D losses)
$0.13	PV of avoided cost of generation capacity
$0.03	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.43	Total Resource Cost test benefits
$0.29	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.29	Total Resource Cost test costs
$0.14	Net TRC $ amount
1.47	**TRC benefit / cost ratio**

HE DX, 10 tons, EER=11.3 (per sq. ft.)



Electric vs gas water, 40 gal., EF=.95 (per sq. ft.)

Summarization of AC benefits and comparison to TRC costs

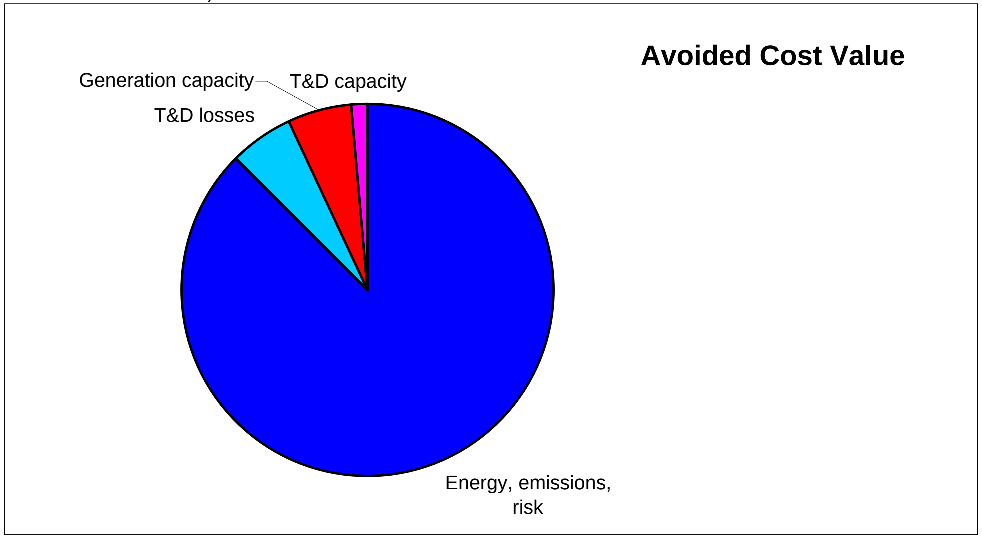
Per first year kW	Per first year kWh		% of total value
	$0.509	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.033	PV of avoided cost of generation capacity	6%
$ 60.28	$ 0.008	PV of avoided cost of T&D capacity	1%
	$0.582		100%
			93% Total energy
			7% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
15	Measure life
3.050	Annual kWh savings per unit
0.0212%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0131%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0610	Levelized cost/kWh of four energy components of AC
$0.0046	Levelized cost/kWh of two capacity components of AC

$1.55	PV of avoided cost of energy (energy + emissions + risk)
$0.10	PV of avoided cost of energy (T&D losses)
$0.10	PV of avoided cost of generation capacity
$0.02	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$1.78	Total Resource Cost test benefits
$0.68	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.68	Total Resource Cost test costs
$1.10	Net TRC $ amount
2.61	**TRC benefit / cost ratio**

Electric vs gas water, 40 gal., EF=.95 (per sq. ft.)



Humidistat controls (grocery, per sq. ft.)

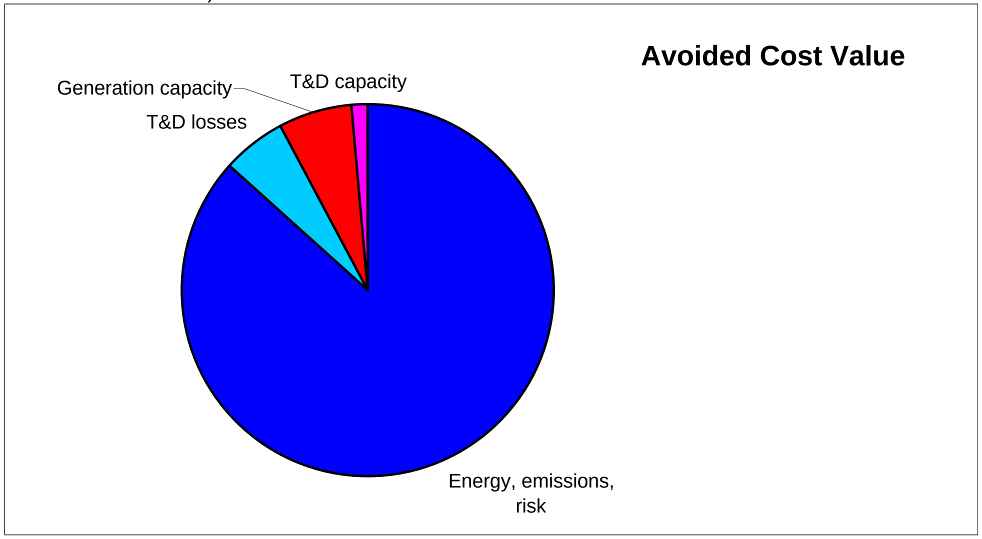
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.414	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.027	PV of avoided cost of energy (T&D losses)	6%
$ 212.09	$ 0.029	PV of avoided cost of generation capacity	6%
$ 51.06	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.478		100%
			92% Total energy
			8% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)	$0.0568	Levelized cost/kWh of four energy components of AC
7.41%	Discount rate	$0.0047	Levelized cost/kWh of two capacity components of AC
12	Measure life		
1.207	Annual kWh savings per unit		
0.0152%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0139%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$0.50	PV of avoided cost of energy (energy + emissions + risk)
$0.03	PV of avoided cost of energy (T&D losses)
$0.04	PV of avoided cost of generation capacity
$0.01	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.58	Total Resource Cost test benefits
$0.02	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.02	Total Resource Cost test costs
$0.56	Net TRC $ amount
28.83	**TRC benefit / cost ratio**

Humidistat controls (grocery, per sq. ft.)



Exit sign replacement (LED)

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.616	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.040	PV of avoided cost of energy (T&D losses)	6%
$ 300.00	$ 0.034	PV of avoided cost of generation capacity	5%
$ 73.31	$ 0.008	PV of avoided cost of T&D capacity	1%
	$0.699		100%
			94% Total energy
			6% Total capacity

non-driver "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

7.41% Discount rate

20 Measure life

351.000 Annual kWh savings per unit

0.0114% Percent of annual energy in maximum hour (use for "driver" measures)

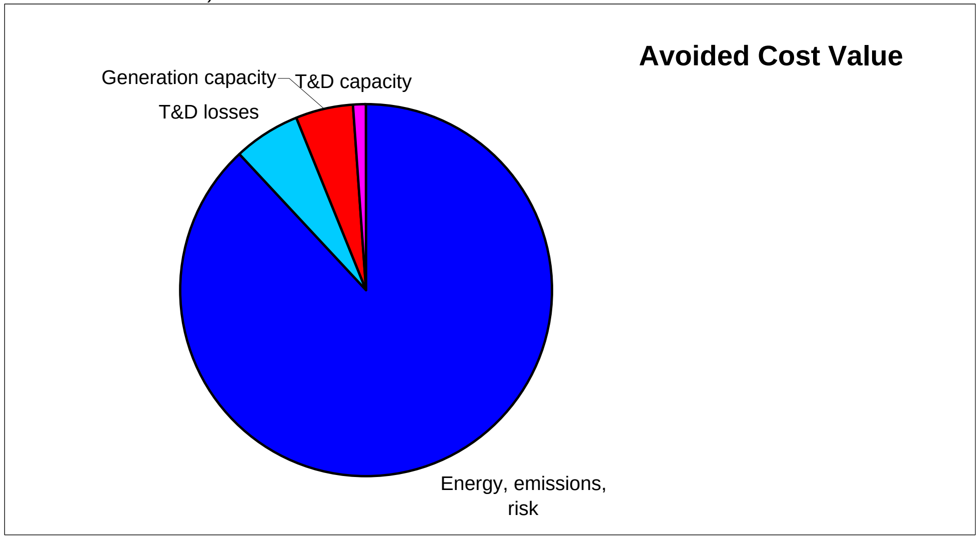
0.0114% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0639 Levelized cost/kWh of four energy components of AC

$0.0042 Levelized cost/kWh of two capacity components of AC

$216.24	PV of avoided cost of energy (energy + emissions + risk)
$14.06	PV of avoided cost of energy (T&D losses)
$12.02	PV of avoided cost of generation capacity
$2.94	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$245.25	Total Resource Cost test benefits
$65.44	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$65.44	Total Resource Cost test costs
$179.81	Net TRC $ amount
3.75	**TRC benefit / cost ratio**

Exit sign replacement (LED)



Light colored roof (from .8 to .45 absorptivity)

Summarization of AC benefits and comparison to TRC costs

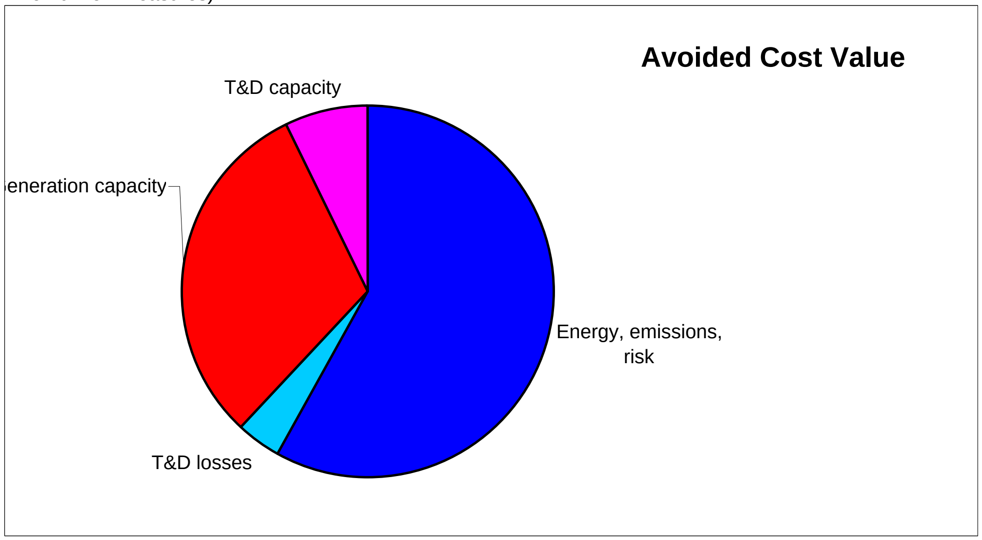
Per first year kW		Per first year kWh			% of total value
			$0.360	PV of avoided cost of energy (energy + emissions + risk)	58%
			$0.023	PV of avoided cost of energy (T&D losses)	4%
$	184.47	$	0.190	PV of avoided cost of generation capacity	31%
$	44.23	$	0.046	PV of avoided cost of T&D capacity	7%
			$0.619		100%

62%	Total energy
38%	Total capacity
$0.0557	Levelized cost/kWh of four energy components of AC
$0.0342	Levelized cost/kWh of two capacity components of AC

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
10	Measure life
0.118	Annual kWh savings per unit
0.1031%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0547%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.04	PV of avoided cost of energy (energy + emissions + risk)
$0.00	PV of avoided cost of energy (T&D losses)
$0.02	PV of avoided cost of generation capacity
$0.01	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.07	Total Resource Cost test benefits
$0.24	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.24	Total Resource Cost test costs
($0.17)	Net TRC $ amount
0.30	**TRC benefit / cost ratio**

Light colored roof (from .8 to .45 absorptivity)



Occupancy sensors for lighting

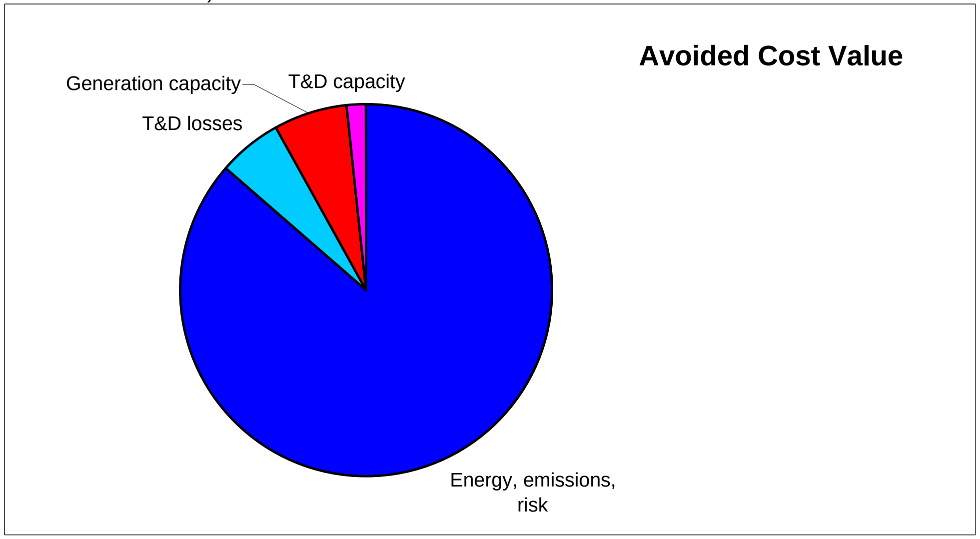
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.481	PV of avoided cost of energy (energy + emissions + risk)	86%
	$0.031	PV of avoided cost of energy (T&D losses)	6%
$ 237.24	$ 0.036	PV of avoided cost of generation capacity	6%
$ 57.34	$ 0.009	PV of avoided cost of T&D capacity	2%
	$0.558		100%
			92% Total energy
			8% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0601	Levelized cost/kWh of four energy components of AC
14	Measure life	$0.0053	Levelized cost/kWh of two capacity components of AC
1.59	Annual kWh savings per unit		
0.0207%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0153%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$0.77	PV of avoided cost of energy (energy + emissions + risk)
$0.05	PV of avoided cost of energy (T&D losses)
$0.06	PV of avoided cost of generation capacity
$0.01	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.89	Total Resource Cost test benefits
$0.58	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.58	Total Resource Cost test costs
$0.31	Net TRC $ amount
1.53	**TRC benefit / cost ratio**

Occupancy sensors for lighting



Light fixture reconfiguration

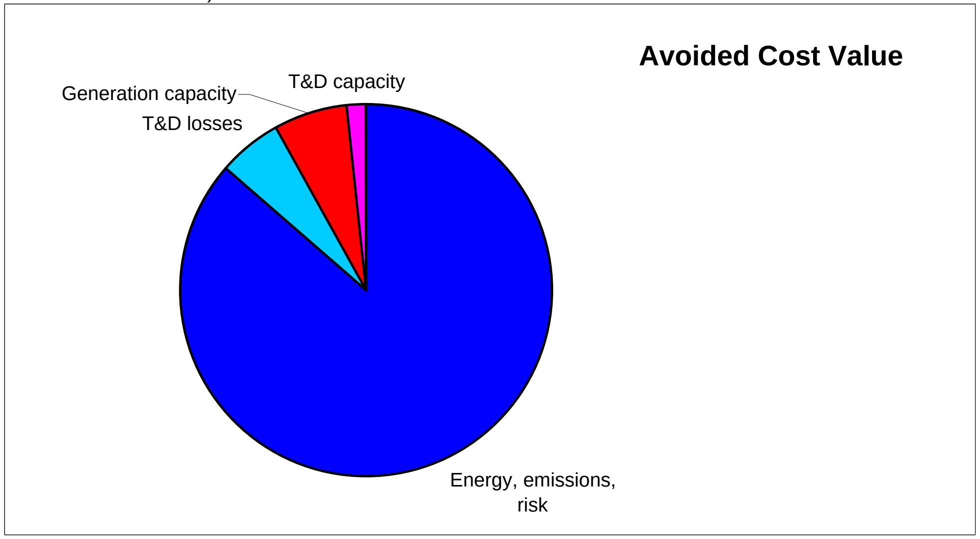
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.535	PV of avoided cost of energy (energy + emissions + risk)	86%
	$0.035	PV of avoided cost of energy (T&D losses)	6%
$ 260.14	$ 0.040	PV of avoided cost of generation capacity	6%
$ 63.11	$ 0.010	PV of avoided cost of T&D capacity	2%
	$0.619		100%
			92% Total energy
			8% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0620	Levelized cost/kWh of four energy components of AC
16	Measure life	$0.0054	Levelized cost/kWh of two capacity components of AC
0.716	Annual kWh savings per unit		
0.0207%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0153%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$0.38	PV of avoided cost of energy (energy + emissions + risk)
$0.02	PV of avoided cost of energy (T&D losses)
$0.03	PV of avoided cost of generation capacity
$0.01	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.44	Total Resource Cost test benefits
$0.50	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.50	Total Resource Cost test costs
($0.06)	Net TRC $ amount
0.89	**TRC benefit / cost ratio**

Light fixture reconfiguration



MH 250 to Pulse Start MH 175, installed

Summarization of AC benefits and comparison to TRC costs

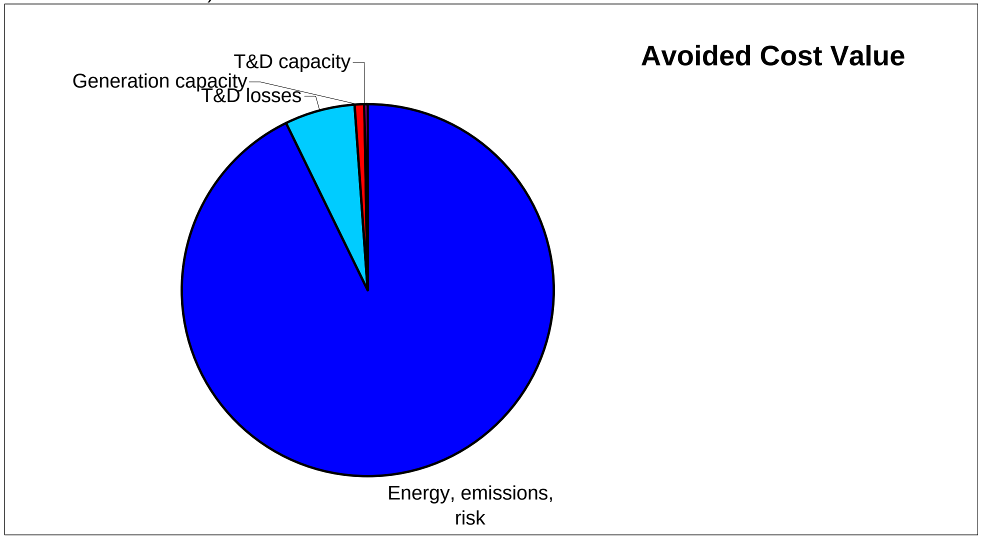
Per first year kW	Per first year kWh		% of total value
	$0.501	PV of avoided cost of energy (energy + emissions + risk)	93%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 260.14	$ 0.005	PV of avoided cost of generation capacity	1%
$ 63.11	$ 0.001	PV of avoided cost of T&D capacity	0%
	$0.540		100%
			99% Total energy
			1% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
16	Measure life
349.000	Annual kWh savings per unit
0.0229%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0020%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0580	Levelized cost/kWh of four energy components of AC
$0.0007	Levelized cost/kWh of two capacity components of AC

$174.77	PV of avoided cost of energy (energy + emissions + risk)
$11.36	PV of avoided cost of energy (T&D losses)
$1.82	PV of avoided cost of generation capacity
$0.44	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$188.39	Total Resource Cost test benefits
$196.86	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$196.86	Total Resource Cost test costs
($8.47)	Net TRC $ amount
0.96	**TRC benefit / cost ratio**

MH 250 to Pulse Start MH 175, installed



MH to T5 Flourescents (400W to 4 HO, 3,000 hr)

Summarization of AC benefits and comparison to TRC costs

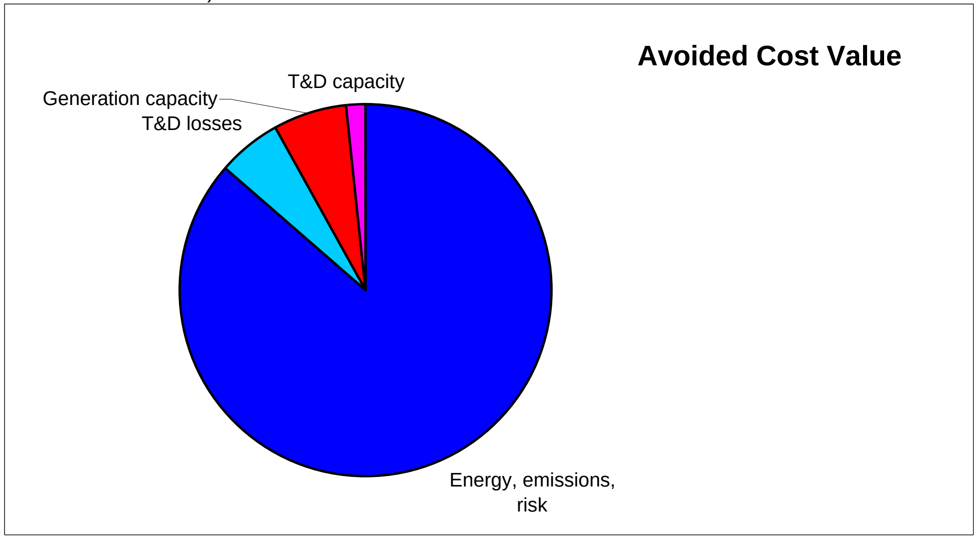
Per first year kW	Per first year kWh		% of total value
	$0.509	PV of avoided cost of energy (energy + emissions + risk)	86%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.038	PV of avoided cost of generation capacity	6%
$ 60.28	$ 0.009	PV of avoided cost of T&D capacity	2%
	$0.589		100%
			92% Total energy
			8% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
15	Measure life
672	Annual kWh savings per unit
0.0207%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0153%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0611	Levelized cost/kWh of four energy components of AC
$0.0053	Levelized cost/kWh of two capacity components of AC

$341.97	PV of avoided cost of energy (energy + emissions + risk)
$22.23	PV of avoided cost of energy (T&D losses)
$25.52	PV of avoided cost of generation capacity
$6.18	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$395.90	Total Resource Cost test benefits
$250.00	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$250.00	Total Resource Cost test costs
$145.90	Net TRC $ amount
1.58	**TRC benefit / cost ratio**

MH to T5 Flourescents (400W to 4 HO, 3,000 hr)



Occupancy sensors for 1-zone A/C & PTAC (per sq. ft.)

Summarization of AC benefits and comparison to TRC costs

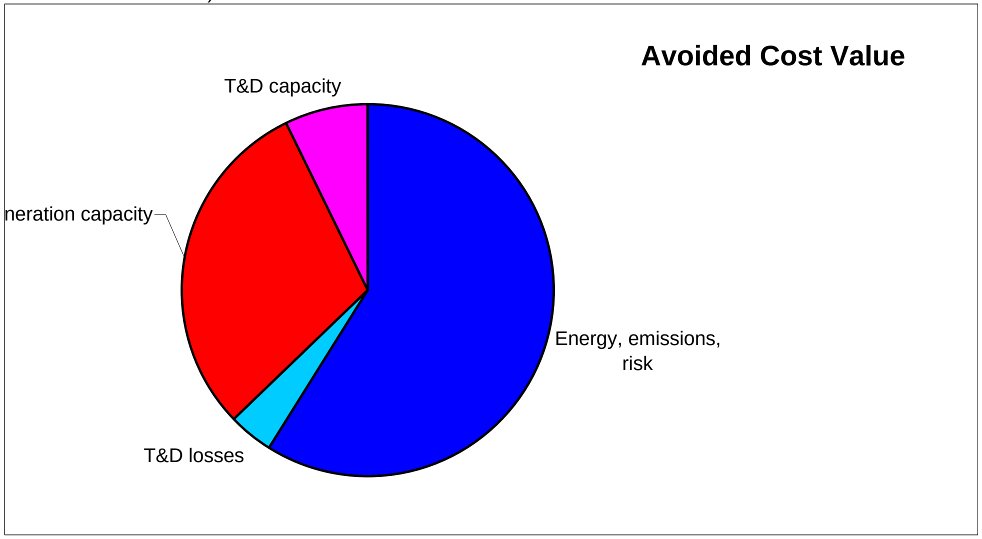
Per first year kW	Per first year kWh		% of total value
	$0.503	PV of avoided cost of energy (energy + emissions + risk)	59%
	$0.033	PV of avoided cost of energy (T&D losses)	4%
$ 248.96	$ 0.257	PV of avoided cost of generation capacity	30%
$ 60.28	$ 0.062	PV of avoided cost of T&D capacity	7%
	$0.854		100%
			63% Total energy
			37% Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
15	Measure life
1.694	Annual kWh savings per unit
0.1031%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0547%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0603	Levelized cost/kWh of four energy components of AC
$0.0359	Levelized cost/kWh of two capacity components of AC

$0.85	PV of avoided cost of energy (energy + emissions + risk)
$0.06	PV of avoided cost of energy (T&D losses)
$0.43	PV of avoided cost of generation capacity
$0.11	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$1.45	Total Resource Cost test benefits
$0.20	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.20	Total Resource Cost test costs
$1.25	Net TRC $ amount
7.23	**TRC benefit / cost ratio**

Occupancy sensors for 1-zone A/C & PTAC (per sq. ft.)



Prescriptive sidestream filtration

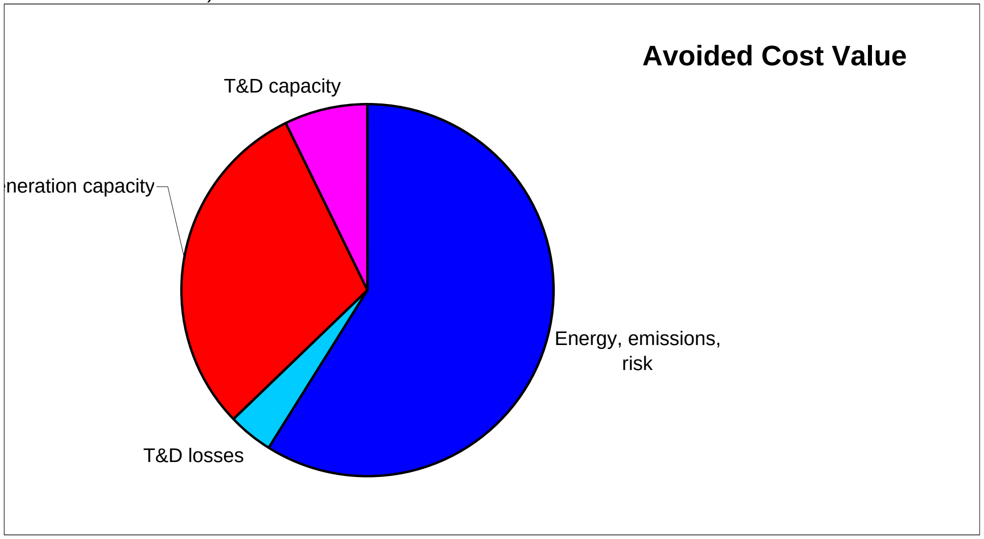
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.503	PV of avoided cost of energy (energy + emissions + risk)	59%
	$0.033	PV of avoided cost of energy (T&D losses)	4%
$ 248.96	$ 0.257	PV of avoided cost of generation capacity	30%
$ 60.28	$ 0.062	PV of avoided cost of T&D capacity	7%
	$0.854		100%
			63% Total energy
			37% Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0603	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0359	Levelized cost/kWh of two capacity components of AC
200,000	Annual kWh savings per unit		
0.1031%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0547%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$100,542.88	PV of avoided cost of energy (energy + emissions + risk)
$6,535.29	PV of avoided cost of energy (T&D losses)
$51,329.97	PV of avoided cost of generation capacity
$12,429.16	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$170,837.29	Total Resource Cost test benefits
$28,000.00	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$28,000.00	Total Resource Cost test costs
$142,837.29	Net TRC $ amount
6.10	**TRC benefit / cost ratio**

Prescriptive sidestream filtration



Refrigeration tune-up/commissioning (per sq. ft.)

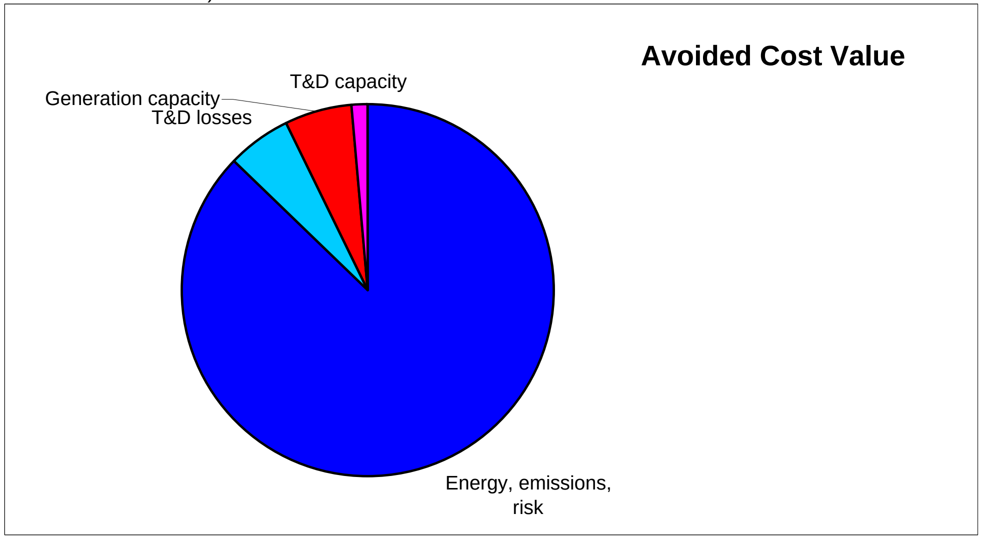
Summarization of AC benefits and comparison to TRC costs

Per first year kW		Per first year kWh			% of total value	
			$0.135	PV of avoided cost of energy (energy + emissions + risk)	87%	
			$0.009	PV of avoided cost of energy (T&D losses)	6%	
$	64.65	$	0.009	PV of avoided cost of generation capacity	6%	
$	15.26	$	0.002	PV of avoided cost of T&D capacity	1%	
			$0.154		100%	
					93%	Total energy
					7%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0550	Levelized cost/kWh of four energy components of AC
3	Measure life	$0.0043	Levelized cost/kWh of two capacity components of AC
1.209	Annual kWh savings per unit		
0.0152%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0139%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$0.16	PV of avoided cost of energy (energy + emissions + risk)
$0.01	PV of avoided cost of energy (T&D losses)
$0.01	PV of avoided cost of generation capacity
$0.00	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.19	Total Resource Cost test benefits
$0.06	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.06	Total Resource Cost test costs
$0.13	Net TRC $ amount
3.11	**TRC benefit / cost ratio**

Refrigeration tune-up/commissioning (per sq. ft.)



Rooftop DX maintenance (per sq. ft.)

Summarization of AC benefits and comparison to TRC costs

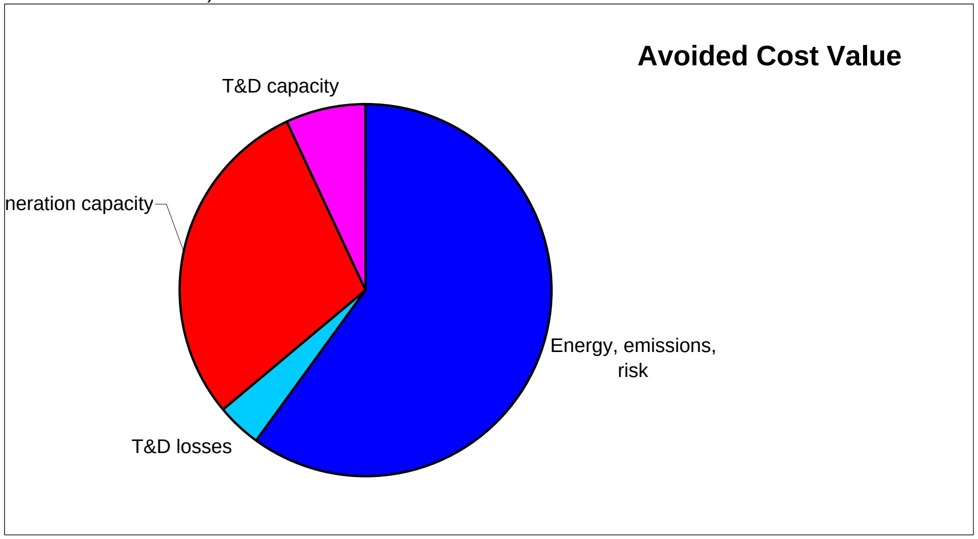
Per first year kW	Per first year kWh		% of total value
	$0.137	PV of avoided cost of energy (energy + emissions + risk)	60%
	$0.009	PV of avoided cost of energy (T&D losses)	4%
$ 64.65	$ 0.067	PV of avoided cost of generation capacity	29%
$ 15.26	$ 0.016	PV of avoided cost of T&D capacity	7%
	$0.228		100%
			64% Total energy
			36% Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
3	Measure life
0.651	Annual kWh savings per unit
0.1031%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0547%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0559	Levelized cost/kWh of four energy components of AC
$0.0316	Levelized cost/kWh of two capacity components of AC

$0.09	PV of avoided cost of energy (energy + emissions + risk)
$0.01	PV of avoided cost of energy (T&D losses)
$0.04	PV of avoided cost of generation capacity
$0.01	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.15	Total Resource Cost test benefits
$0.23	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.23	Total Resource Cost test costs
($0.08)	Net TRC $ amount
0.65	**TRC benefit / cost ratio**

Rooftop DX maintenance (per sq. ft.)



Pre-rinse sprayers

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.208	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.014	PV of avoided cost of energy (T&D losses)	6%
$ 102.97	$ 0.013	PV of avoided cost of generation capacity	6%
$ 24.42	$ 0.003	PV of avoided cost of T&D capacity	1%
	$0.239		100%

93% Total energy

7% Total capacity

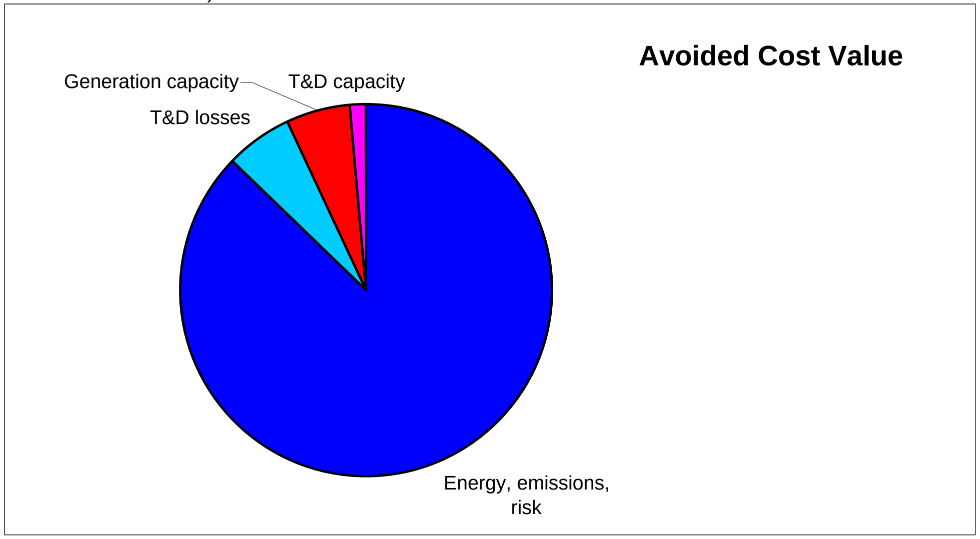
$0.0547 Levelized cost/kWh of four energy components of AC

$0.0041 Levelized cost/kWh of two capacity components of AC

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
5	Measure life
3,800.000	Annual kWh savings per unit
0.0212%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0131%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$792.01	PV of avoided cost of energy (energy + emissions + risk)
$51.48	PV of avoided cost of energy (T&D losses)
$51.13	PV of avoided cost of generation capacity
$12.13	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$906.74	Total Resource Cost test benefits
$162.00	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$162.00	Total Resource Cost test costs
$744.74	Net TRC $ amount
5.60	**TRC benefit / cost ratio**

Pre-rinse sprayers



CFL 20W screw-in for incandescent 75W (retrofit)

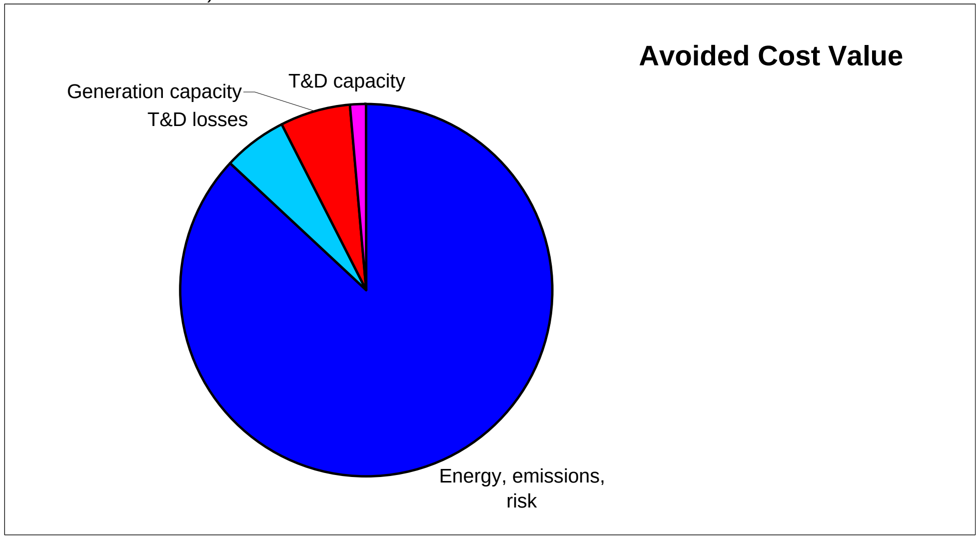
Summarization of AC benefits and comparison to TRC costs

Per first year kW		Per first year kWh			% of total value
			$0.096	PV of avoided cost of energy (energy + emissions + risk)	87%
			$0.006	PV of avoided cost of energy (T&D losses)	6%
$	44.10	$	0.007	PV of avoided cost of generation capacity	6%
$	10.39	$	0.002	PV of avoided cost of T&D capacity	1%
			$0.111		100%
					93% Total energy
					7% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0545	Levelized cost/kWh of four energy components of AC
2.1	Measure life	$0.0044	Levelized cost/kWh of two capacity components of AC
260	Annual kWh savings per unit		
0.0207%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0153%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$25.05	PV of avoided cost of energy (energy + emissions + risk)
$1.63	PV of avoided cost of energy (T&D losses)
$1.75	PV of avoided cost of generation capacity
$0.41	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$28.84	Total Resource Cost test benefits
$10.25	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$10.25	Total Resource Cost test costs
$18.59	Net TRC $ amount
2.81	**TRC benefit / cost ratio**

CFL 20W screw-in for incandescent 75W (retrofit)



Prescriptive sidestream filtration

Summarization of AC benefits and comparison to TRC costs

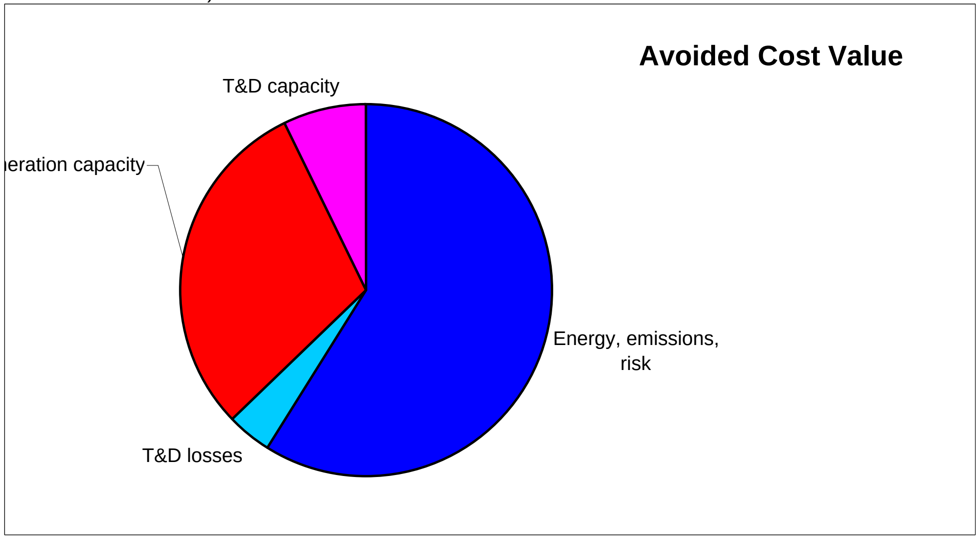
Per first year kW	Per first year kWh		% of total value
	$0.503	PV of avoided cost of energy (energy + emissions + risk)	59%
	$0.033	PV of avoided cost of energy (T&D losses)	4%
$ 248.96	$ 0.257	PV of avoided cost of generation capacity	30%
$ 60.28	$ 0.062	PV of avoided cost of T&D capacity	7%
	$0.854		100%
			63% Total energy
			37% Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
15	Measure life
200,000	Annual kWh savings per unit
0.1031%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0547%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0603	Levelized cost/kWh of four energy components of AC
$0.0359	Levelized cost/kWh of two capacity components of AC

$100,542.88	PV of avoided cost of energy (energy + emissions + risk)
$6,535.29	PV of avoided cost of energy (T&D losses)
$51,329.97	PV of avoided cost of generation capacity
$12,429.16	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$170,837.29	Total Resource Cost test benefits
$28,000.00	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$28,000.00	Total Resource Cost test costs
$142,837.29	Net TRC $ amount
6.10	**TRC benefit / cost ratio**

Prescriptive sidestream filtration



Signage: incadescent to LED/incadescent to cold cathode

Summarization of AC benefits and comparison to TRC costs

Per first year kW		Per first year kWh			% of total value
			$0.194	PV of avoided cost of energy (energy + emissions + risk)	93%
			$0.013	PV of avoided cost of energy (T&D losses)	6%
$	102.97	$	0.002	PV of avoided cost of generation capacity	1%
$	24.42	$	0.000	PV of avoided cost of T&D capacity	0%
			$0.209		100%

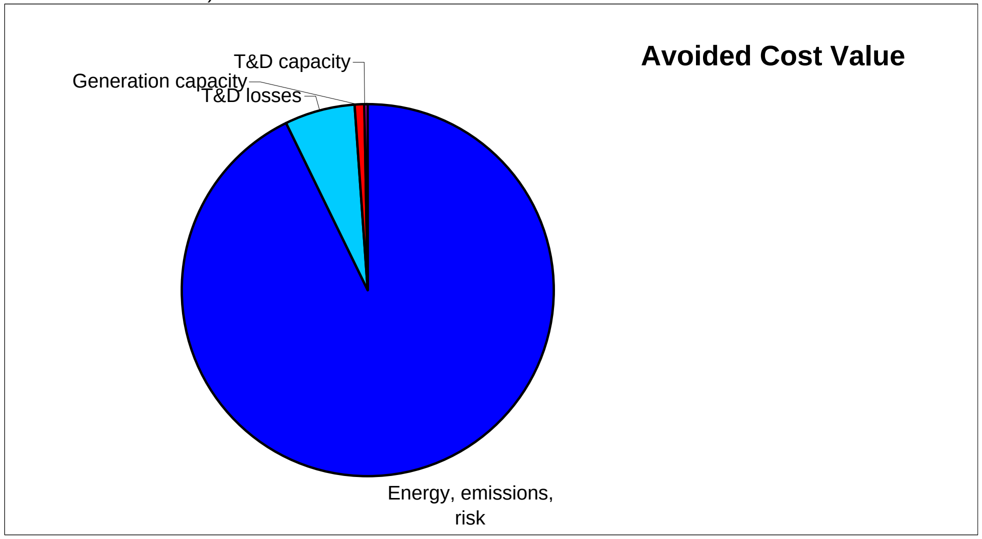
99% Total energy
1% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
5	Measure life
74.000	Annual kWh savings per unit
0.0229%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0020%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0509	Levelized cost/kWh of four energy components of AC
$0.0006	Levelized cost/kWh of two capacity components of AC

$14.35	PV of avoided cost of energy (energy + emissions + risk)
$0.93	PV of avoided cost of energy (T&D losses)
$0.15	PV of avoided cost of generation capacity
$0.04	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$15.47	Total Resource Cost test benefits
$15.00	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$15.00	Total Resource Cost test costs
$0.47	Net TRC $ amount
1.03	**TRC benefit / cost ratio**

Signage: incadescent to LED/incadescent to cold cathode



Smart programmable thermostat (per sq. ft.)

Summarization of AC benefits and comparison to TRC costs

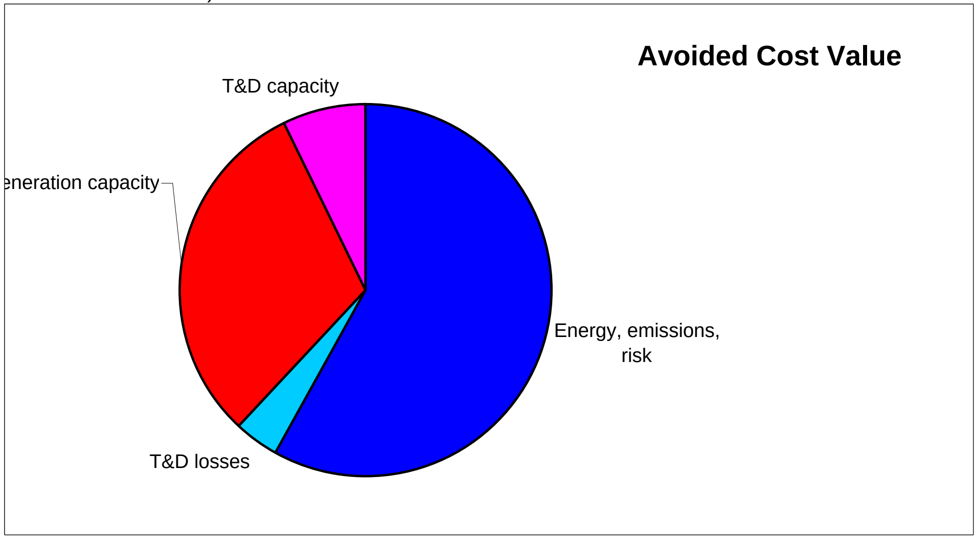
Per first year kW	Per first year kWh		% of total value
	$0.360	PV of avoided cost of energy (energy + emissions + risk)	58%
	$0.023	PV of avoided cost of energy (T&D losses)	4%
$ 184.47	$ 0.190	PV of avoided cost of generation capacity	31%
$ 44.23	$ 0.046	PV of avoided cost of T&D capacity	7%
	$0.619		100%
			62% Total energy
			38% Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
10	Measure life
0.279	Annual kWh savings per unit
0.1031%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0547%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0557	Levelized cost/kWh of four energy components of AC
$0.0342	Levelized cost/kWh of two capacity components of AC

$0.10	PV of avoided cost of energy (energy + emissions + risk)
$0.01	PV of avoided cost of energy (T&D losses)
$0.05	PV of avoided cost of generation capacity
$0.01	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.17	Total Resource Cost test benefits
$0.15	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.15	Total Resource Cost test costs
$0.02	Net TRC $ amount
1.15	**TRC benefit / cost ratio**

Smart programmable thermostat (per sq. ft.)



Solar water heating

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.509	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.033	PV of avoided cost of generation capacity	6%
$ 60.28	$ 0.008	PV of avoided cost of T&D capacity	1%
	$0.582		100%

93% Total energy

7% Total capacity

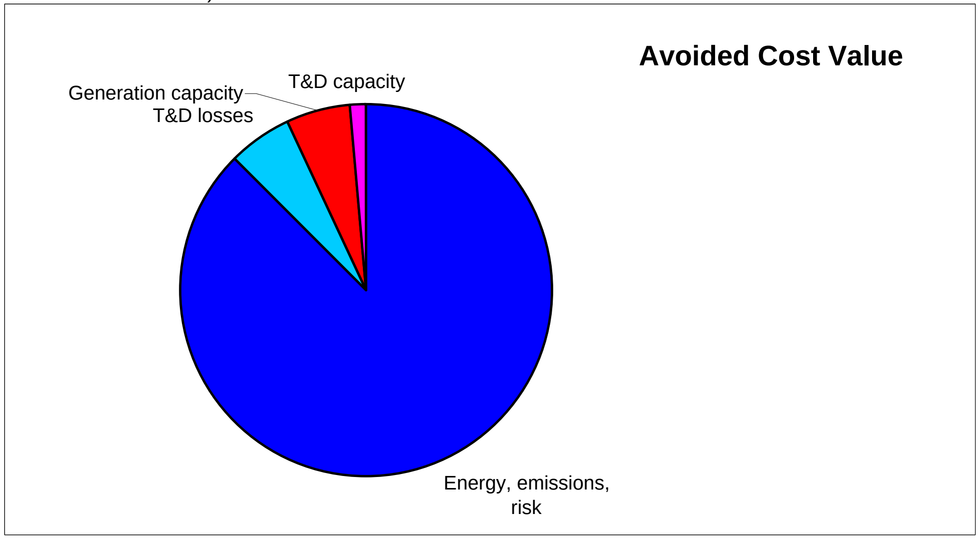
$0.0610 Levelized cost/kWh of four energy components of AC

$0.0046 Levelized cost/kWh of two capacity components of AC

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
15	Measure life
2,566.000	Annual kWh savings per unit
0.0212%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0131%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$1,305.08	PV of avoided cost of energy (energy + emissions + risk)
$84.83	PV of avoided cost of energy (T&D losses)
$83.48	PV of avoided cost of generation capacity
$20.21	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$1,493.59	Total Resource Cost test benefits
$5,310.00	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$5,310.00	Total Resource Cost test costs
($3,816.41)	Net TRC $ amount
0.28	**TRC benefit / cost ratio**

Solar water heating



T12 EEmag to Super T8 Flourescents (retrofit)

Summarization of AC benefits and comparison to TRC costs

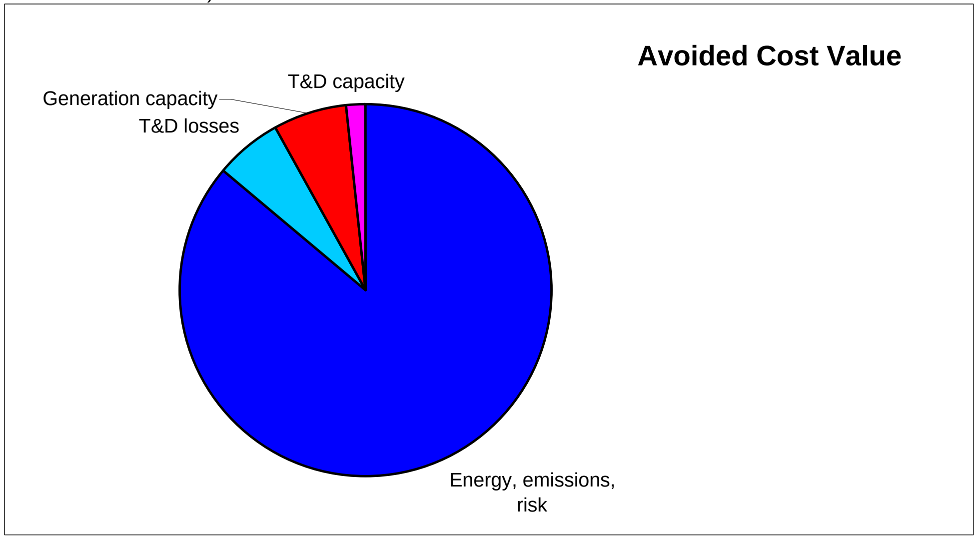
Per first year kW	Per first year kWh		% of total value
	$0.396	PV of avoided cost of energy (energy + emissions + risk)	86%
	$0.026	PV of avoided cost of energy (T&D losses)	6%
$ 198.60	$ 0.030	PV of avoided cost of generation capacity	7%
$ 47.71	$ 0.007	PV of avoided cost of T&D capacity	2%
	$0.459		100%
			92% Total energy
			8% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
11	Measure life
105	Annual kWh savings per unit
0.0207%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0153%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0573	Levelized cost/kWh of four energy components of AC
$0.0051	Levelized cost/kWh of two capacity components of AC

$41.54	PV of avoided cost of energy (energy + emissions + risk)
$2.70	PV of avoided cost of energy (T&D losses)
$3.18	PV of avoided cost of generation capacity
$0.76	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$48.18	Total Resource Cost test benefits
$26.84	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$26.84	Total Resource Cost test costs
$21.34	Net TRC $ amount
1.80	**TRC benefit / cost ratio**

T12 EEmag to Super T8 Flourescents (retrofit)



Commissioning/retro-commissioning

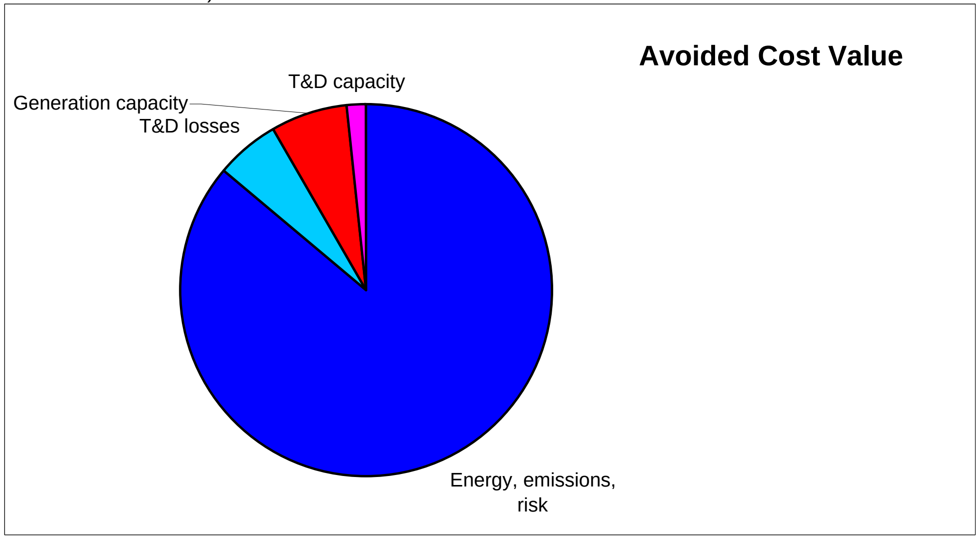
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh			% of total value	
		$0.363	PV of avoided cost of energy (energy + emissions + risk)	86%	
		$0.024	PV of avoided cost of energy (T&D losses)	6%	
$ 184.47	$	0.028	PV of avoided cost of generation capacity	7%	
$ 44.23	$	0.007	PV of avoided cost of T&D capacity	2%	
		$0.422		100%	
				92%	Total energy

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)	8%	Total capacity
7.41%	Discount rate	$0.0561	Levelized cost/kWh of four energy components of AC
10	Measure life	$0.0051	Levelized cost/kWh of two capacity components of AC
1,612.000	Annual kWh savings per unit		
0.0205%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0154%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$585.70	PV of avoided cost of energy (energy + emissions + risk)
$38.07	PV of avoided cost of energy (T&D losses)
$45.81	PV of avoided cost of generation capacity
$10.98	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$680.57	Total Resource Cost test benefits
$215.50	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$215.50	Total Resource Cost test costs
$465.07	Net TRC $ amount
3.16	**TRC benefit / cost ratio**

Commissioning/retro-commissioning vm



VF Drives for HVAC

Summarization of AC benefits and comparison to TRC costs

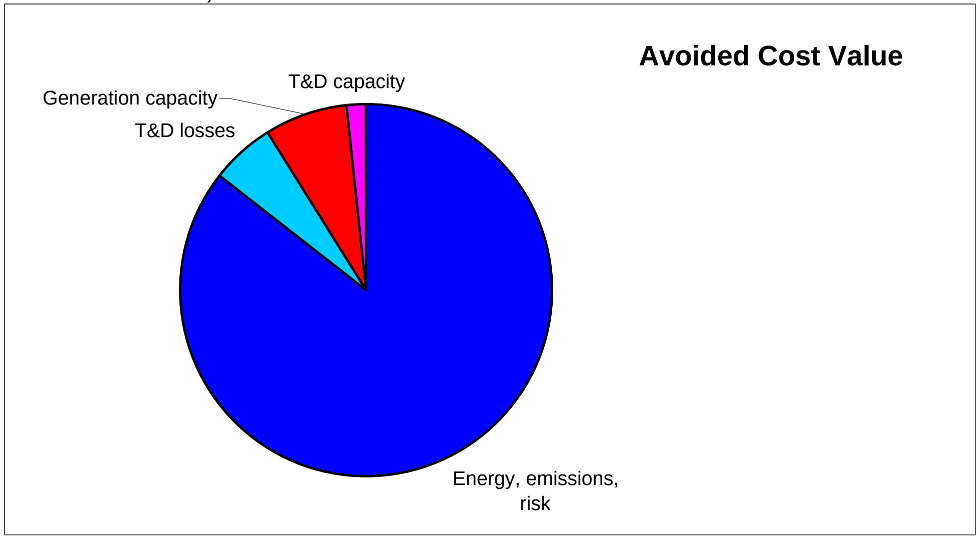
Per first year kW	Per first year kWh		% of total value
	$0.503	PV of avoided cost of energy (energy + emissions + risk)	86%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.042	PV of avoided cost of generation capacity	7%
$ 60.28	$ 0.010	PV of avoided cost of T&D capacity	2%
	$0.588		100%
			91% Total energy
			9% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
15	Measure life
0.675	Annual kWh savings per unit
0.0217%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0170%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0604	Levelized cost/kWh of four energy components of AC
$0.0059	Levelized cost/kWh of two capacity components of AC

$0.34	PV of avoided cost of energy (energy + emissions + risk)
$0.02	PV of avoided cost of energy (T&D losses)
$0.03	PV of avoided cost of generation capacity
$0.01	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.40	Total Resource Cost test benefits
$0.21	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.21	Total Resource Cost test costs
$0.19	Net TRC $ amount
1.89	**TRC benefit / cost ratio**

VF Drives for HVAC



Window films

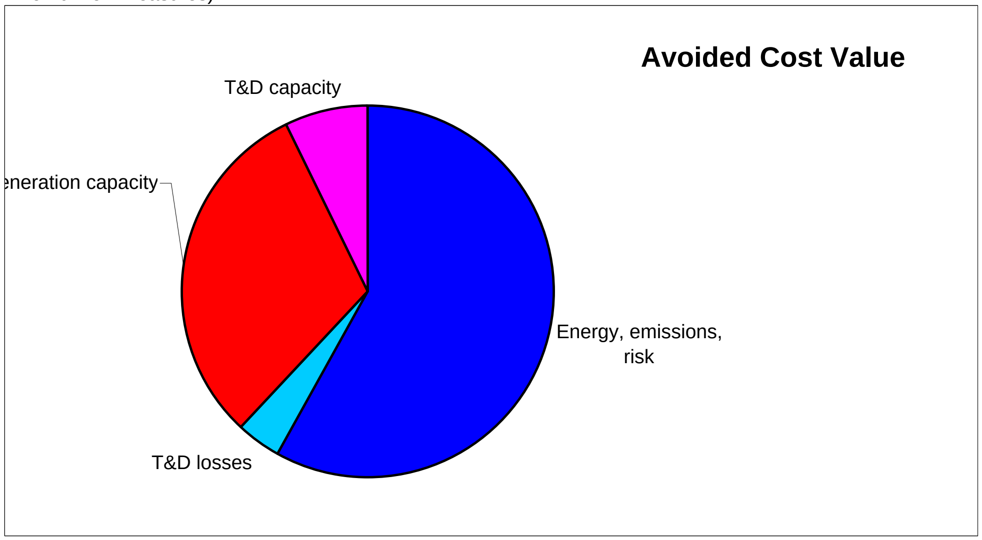
Summarization of AC benefits and comparison to TRC costs

Per first year kW		Per first year kWh			% of total value
			$0.360	PV of avoided cost of energy (energy + emissions + risk)	58%
			$0.023	PV of avoided cost of energy (T&D losses)	4%
$	184.47	$	0.190	PV of avoided cost of generation capacity	31%
$	44.23	$	0.046	PV of avoided cost of T&D capacity	7%
			$0.619		100%
					62% Total energy
					38% Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0557	Levelized cost/kWh of four energy components of AC
10	Measure life	$0.0342	Levelized cost/kWh of two capacity components of AC
50.000	Annual kWh savings per unit		
0.1031%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0547%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$18.01	PV of avoided cost of energy (energy + emissions + risk)
$1.17	PV of avoided cost of energy (T&D losses)
$9.51	PV of avoided cost of generation capacity
$2.28	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$30.97	Total Resource Cost test benefits
$100.00	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$100.00	Total Resource Cost test costs
($69.03)	Net TRC $ amount
0.31	**TRC benefit / cost ratio**

Window films



Estimated Resource Integration Costs

March 26, 2007

R. Gnaedinger
S. Koeff
S. Waples

Estimated Resource Integration Costs for the 2007 IRP

Introduction

Avista-LSE requested integration costs for potential future resources to meet its state-jurisdictional service obligations to Avista's bundled retail native load customers. While points of integration are critical for this discussion, the type of generation is immaterial. Future resources may vary in fuel type, but these variations are not considered in this study.

Several different project sizes were requested for this analysis: 50 MW, 100 MW, 250 MW and over 400 MW. Transmission capability comes in "lumps" and plant sizes may be able to be altered based upon transmission capacity that might be available at a particular site, so we have separated the alternatives into 50 MW, 100 MW, 400 MW, 750 MW and 1,*000 MW sizes. If an alternative is requested for 50 or 100 MW, only those will be discussed; however the 400, 750 and 1,000 MW sizes will be discussed separately for the projects over 400 MW.

The various integration points requested for this study have been roughly divided into two classes: those which would integrate directly onto Avista's transmission system, and those that would integrate on other transmission systems. Integration of large amounts of generation on our system could fit into both classes since there would be broad impacts to both our system and neighboring systems. It should be noted that rigorous study has not been completed for any of the alternatives where the resources would be integrated on a foreign system (the estimates presented below are based on engineering judgment only), because it is not possible to provide meaningful results without the knowledge, input and approval of the owners of those systems. If a detailed cost and capacity estimate of these options became necessary, Avista-LSE would be required to request transmission from these other systems and would need to pay for any study work that these systems deem necessary. Therefore, the costs provided are not, and can not be, construction estimate quality. Additionally, only limited study work has been done for the alternatives within our system; comprehensive study work requires detailed machine parameters which are available only when an actual project is specified.

Also note that as the size of the resource to be integrated increases, the certainty of any estimates becomes less precise. A 50 MW resource can be integrated in many places on the Avista system with relatively little system impact, and likely little or no impact on neighboring systems. Projects over 400 MW can be integrated only in specific areas, which will most likely impact neighboring systems. Due to the uncertainty of impacts to any system where such resources would be integrated as well as the most likely significant impacts to neighboring systems, an approximate worst case cost estimate has been assigned based on engineering judgment.

Depending upon the size, scope, placement, and timing of a new resource, a detailed regional process may be required to determine the exact system impacts and integration/mitigation costs for all affected systems. This process may increase complexity, cost, and time to project energization.

Interconnection costs listed for locations within the Avista transmission system include all costs beyond the fence line of the plant location including transmission to and substation equipment at the interconnection point. Substation costs include any additional substation upgrades that are needed beyond upgrades needed at the interconnection point. Transmission costs include all costs to add/upgrade transmission beyond the transmission needed to get to the interconnection point. The annual operation and maintenance (O&M) costs for the transmission system are calculated from Avista's 2005 FERC form No. 1 financial report. The report was used to calculate an average annual O&M cost for Avista's transmission system on a per mile basis. All internal cost estimates are in 2015 year dollars and are based on engineering judgment with +/- 50% error.

Time to construct, for this study, is defined from the beginning of the permitting process to the final energization date for.

External to the Avista System

Boardman, Oregon

The present transmission system which serves the Boardman generating complex consists of two 500 kV circuits which are owned and operated by Portland General Electric (PGE) which integrate into several 500 kV circuits owned and operated by the Bonneville Power Administration (BPA). Boardman lies to the north and east of several transmission constraints which could be an issue with respect to BPA's transmission pricing and availability policies.

Because Avista owns no transmission in the Boardman area, Avista-LSE would be required to undertake a transmission request on the PGE system and would also be required to fund a study to determine potential impacts caused by this project on BPA. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area. Note that since two transmission systems (other than the Avista system) would be involved in the integration of this project, Avista-LSE would pay two wheeling charges or "pancaked" rates for transmission service.

The following estimates might be reasonable for integration of energy at this site:

400 MW: 400 MW would most likely require reinforcement to both PGE and BPA's "local" 500 kV system, and might require additional 500 kV facilities "downstream" of the plant. Engineering estimates of construction costs (taken from the recent Canada>Northwest>California integration studies) are $1.4M per mile for construction of new 500 kV lines. Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown.

750 MW: 750 MW almost certainly requires reinforcement to both PGE and BPA's "local" 500 kV grid in the area, and would also almost certainly require additional 500 kV facilities "downstream" of the plant. Engineering estimates of construction costs (taken from the recent Canada>Northwest>California integration studies) are $1.4M per mile for construction of new 500 kV lines. Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown.

1000 MW: 1000 MW would most likely require an additional 500 kV line in the local area, and would almost certainly require additional 500 kV facilities "downstream" of the plant. Engineering estimates of construction costs (taken from the recent Canada>Northwest>California integration studies) are $1.4M per mile for construction of new 500 kV lines. Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown.

As noted above, a regional study under the auspices of the Northwest Power Pool NTAC would likely be necessary to integrate more that 400 MW of resources at this site.

John Day, Washington

The transmission system which presently serves the John Day generating complex consists of several 500 kV circuits which are owned and operated by BPA. John Day is to the north and east of several transmission constraints which could be an issue with respect to BPA's transmission pricing and availability policies.

Because Avista owns no transmission in the John Day area, Avista-LSE would be required to undertake a transmission request on the BPA transmission system. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area.

The following estimates might be reasonable for integration of energy at this site:

50 MW: The North of John Day Path is presently in a constrained state, depending upon generation on the upper and mid Columbia River. Because of these existing constraints, a transmission integration study on the BPA system would be required to determine if 50 MW would be able to be integrated at a low cost.

100 MW: The North of John Day Path is presently in a constrained state, depending upon generation on the upper and mid Columbia River. Because of these existing constraints, a transmission integration study on the BPA system would be required to determine if 100 MW would be able to be integrated at a low cost.

Because this is presently a constrained path, a regional study under the auspices of the Northwest Power Pool NTAC would likely be necessary to integrate any new resources at this site.

Kalama, Washington

The transmission system which presently serves the Kalama area consists of two 500 kV circuits and two 230 kV circuits, all of which are owned and operated by BPA. This area lies in the center of several transmission constraints (from Canada to and into California) which could be an issue with respect to BPA's transmission pricing and availability policies.

Because Avista owns no transmission in the Kalama area, Avista-LSE would be required to undertake a transmission request on the BPA transmission system. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area.

The following estimates might be reasonable for integration of energy at this site:

400 MW: 400 MW would most likely require reinforcement to BPA's "local" 500 kV system, and might require additional 500 kV facilities "downstream" of the plant. Engineering estimates of construction costs (taken from the recent Canada>Northwest>California integration studies) are $1.4M per mile for construction of new 500 kV lines. Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown.

750 MW: 750 MW almost certainly require reinforcement to BPA's "local" 500 kV grid in the area, and would also almost certainly require additional 500 kV facilities "downstream" of the plant. Engineering estimates of construction costs (taken from the recent Canada>Northwest>California integration studies) are $1.4M per mile for construction of new

500 kV lines. Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown.

1000 MW: 1000 MW would most likely require an additional 500 kV line in the local area, and would almost certainly require additional 500 kV facilities "downstream" of the plant. Engineering estimates of construction costs (taken from the recent Canada>Northwest>California integration studies) are $1.4 million per mile for construction of new 500 kV lines. Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown- although the costs for this alternative could be well over $1.5 billion.

As noted above, a regional study under the auspices of the Northwest Power Pool NTAC would likely be necessary to integrate more that 400 MW of resources at this site.

LaGrande, Oregon

The transmission system which presently serves the LaGrande area consists of a 230 kV line which is owned and operated by BPA and which terminates at McNary, and a 230 kV line which is owned and operated by Idaho Power Company (IPC) and which terminates at Brownlee. IPC also owns a 69 kV line out of LaGrande which is normally operated in a radial configuration. LaGrande lies in the center of one of the four lines which make up the Idaho>Northwest transmission path (the Brownlee-McNary 230 kV line). There is presently a WECC rating process that is being undertaken for the Idaho>Northwest path which could affect any potential available transmission capacity on these lines.

Because Avista owns no transmission in the LaGrande area, Avista-LSE would be required to undertake a transmission request on either the BPA or IPC transmission systems. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area.

50 or 100 MW: Because of the above rating study, there is no way to perform a reasonable study for additional generation in this area until that study has been resolved.

Because this is presently a constrained path, a regional study under the auspices of the Northwest Power Pool NTAC would likely be necessary to integrate any new resources at this site.

Northeast Wyoming

The transmission system which presently serves northeastern Wyoming consists of several 230 kV circuits which are owned and operated by PacifiCorp and Black Hills Power Company. Additional circuits are owned by or presently planned by Basin Electric. Northeast Wyoming is south, north, east, and west of several transmission constraints.

Because Avista owns no transmission in northeastern Wyoming, Avista-LSE would be required to undertake a transmission request on one of the multiple transmission systems in the area. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area.

The following estimates might be reasonable for integration of energy at this site:

400-1000 MW: Because there are constraints from this area both to the north and west (Montana-Wyoming, as well as all of the serial constraints from the Colstrip area to the Spokane area) and to the south and west (the Bridger transmission system, Path C, and Idaho>Northwest), moving 400-1000 MW from this area into our native system would be difficult, time consuming, and most likely quite expensive from a construction standpoint. In the lowest power, lowest cost case at least one 500 kV line would be required (at least as far as into the IPC system). In the 1000 MW case, two 500 kV lines might well be required. In addition, depending upon the arrangements, wheeling expense might also be incurred.

Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown- although the costs for this effort could be between $2.0 and $3.0 billion.

A regional study would likely be needed to integrate more that 400 MW of resources at this site.

Southeast Idaho

The transmission system which presently serves southeastern Idaho consists of a 500 kV line, several 345 kV lines, and several 230 kV circuits which are owned and operated by PacifiCorp and IPC. Southeastern Idaho is east and west of several transmission constraints.

Because Avista owns no transmission in southeastern Idaho, Avista-LSE would be required to undertake a transmission request on either the PacifiCorp or IPC systems in the area. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area.

The following estimates are reasonable expectations for integration costs at this site:

400-1000 MW: Because there are constraints from this area both to the east and west (Path C as well as Idaho>Northwest), moving 400-1000 MW from this area into our native system would be difficult, time consuming, and most likely quite expensive from a construction standpoint. In the lowest power, lowest cost case at least one additional 345 kV line would be required (at least as far as into the center of the IPC system). In the 1000 MW case, two 500 kV lines might well be required, all of the way to the Avista system. In addition, depending upon the arrangements, wheeling expense might also be incurred. Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown, although the costs for this effort could be between $1.0 and $3.0 billion.

As noted above, a regional study would likely be necessary to integrate more that 400 MW of resources at this site.

Central Alberta, Canada

Presently, there is no available transfer capability, nor is there any suitable method of inexpensively integrating energy from central Alberta into the Avista system. Because of the distances and costs involved, integration into the United States power grid at capacity levels less than 2000-3000 MW is unlikely. Because of the capacity required for the economics of the project to “pencil”, it is anticipated that transmission from central Alberta would be a direct current (DC) 500 kV line. It is assumed that one of the DC terminals would be either in the Spokane area or at the Mid-Columbia. Avista could then purchase portions of this energy to be delivered to its system from either of those places. It should be noted that a regional scoping effort to estimate costs for this (and other similar) project(s) has just been completed and can be obtained (assuming the requirements for obtaining Critical Infrastructure Information are met) from the Northwest Power Pool. Estimates for these projects are in the range of two to five billion dollars.

The following estimates might be reasonable for integration of energy at this site:

50 – 250 MW: A 300 MW transmission interconnection project between southern Alberta and northern Montana (MATL) has been proposed. Available capacity on this project is not known at this time. However, additional transmission would be required between central Alberta and southern Alberta, as well as from northern Montana to the Spokane area (which passes through the Great Falls-Garrison constraints as well as the Montana>Northwest constraints). Until it is known if the MATL project will be constructed, it is difficult to provide estimates on whether 50 MW of energy can be economically integrated into our system from central Alberta. Note that Avista-LSE would be required to undertake a transmission request on the BPA system for this service. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area.

400-1000-3000 MW: Integration of anything over 300 MW would most likely require a high voltage DC tie directly from the resource, which would most likely be integrated into the Mid-Columbia area. Please see the attached CNC study to determine estimates of integration costs. Integration of more than 400 MW from the Mid-Columbia would be expected to cost in the range of $300 – 500 million. Note that this is exclusive of the 500 kV DC tie project.

As noted above, a regional study would likely be necessary to integrate more that 400 MW of resources at this site.

Central Washington

The transmission system which presently serves the Central Washington area consists of a couple 500 kV circuits and several 230 kV circuits which are owned and operated by several entities. One of the 230 kV lines into the Mid-Columbia area is jointly owned by Avista and PacifiCorp. However, presently there is no long term available transfer capability from central Washington into the Avista system via the jointly owned transmission line. There is a regional study through the Northwest Power Pool in progress which will be analyzing resource integration in the Mid-Columbia area (which includes Avista's system). This study should be complete sometime in mid 2007.

The following estimates might be reasonable for integration of energy at this site:

50 – 300 MW: The Mid-Columbia area is presently in a constrained state, depending upon generation on the mid Columbia River. Because of these existing constraints, a transmission integration study (most likely on the BPA or Avista system) would be required to determine if 50 MW would be able to be integrated.

400-1000 MW: The integration of more than 400 MW from the Mid-Columbia would be expected to cost in the range of $300 – 500 million.

As noted above, a regional study would likely be necessary to integrate more that 400 MW of resources at this site.

Eastern Montana

The present transmission system to the west of (and serving) the present generation in Montana is a double circuit 500 kV line and two 230 kV lines. A regional study under the auspices of the Northwest Power Pool (NWPP) NTAC was completed last year which indicates that either additional transmission or transmission upgrades would need to be constructed for integration of energy from Montana. Eastern Montana is also to the east of several transmission constraints

(West of Colstrip, West of Broadview, West of Garrison, Montana to the Northwest, and West of Hatwai) which could be an issue with respect to BPA's transmission pricing and availability policies.

A more detailed study effort which will focus on constraints from Central and Eastern Montana has recently been announced. This study will clearly identify constraints and costs for such integration. It is expected that results of this study will be released some time in early 2007.

Avista-LSE would be required to undertake a transmission request on the NWE system and would also be required to fund a study to determine potential impacts caused by this project on the BPA system. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area. Note that since two transmission systems (BPA and Northwestern Energy) may be involved in the integration of this project, the merchant may pay two wheeling charges or "pancaked" rates for transmission service.

Walla Walla, Washington:

The present transmission system serving the Walla Walla, Washington area is a single 230 kV line with dual ownership by Avista and PacifiCorp. There is also a 115 kV line in the area owned by BPA and a 69 kV line owned by PacifiCorp.

Avista has contractual transmission rights, but owns no transmission in the Walla Walla area. Therefore, Avista-LSE would be required to undertake a transmission request on the PacifiCorp transmission system. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area.

50 or 100 MW: Due to the presently constrained paths in the area, such as the Idaho to Northwest path, a transmission integration study on the PacifiCorp system would be required to determine integration costs.

Because there are presently constrained paths in the area, a regional study under the auspices of the Northwest Power Pool NTAC would likely be necessary to integrate any new resources at this site.

Internal to the Avista System

Sprague, Washington

The present transmission system serving the Sprague, Washington area is a low capacity 115 kV line. It would not be suitable for integration of 250-400 MW in its present configuration. Each connection below (which are the major transmission interconnection points in the area), would require 230 kV transmission and substation work for the generation integration. Any added generation greater than 400 MW will simply further increase costs and regional impacts.

The following estimates might be reasonable for integration of energy at this site:

250 MW: It is expected to integrate 250 MW at Westside, the existing 115 kV would have to be rebuilt 230/115 double circuit back to the main BPA corridor. Then to connect at Westside additional 230 kV would be constructed utilizing BPA's transmission or by building new 230 kV. The time to construct will be approximately 4 years.

Cost: Interconnection $994k/mile (total miles = 56 at 800 MVA capacity)

Transmission $0

Substation $2M

<u>**Annual O&M $300k**</u>

Total $58 million

It is expected to integrate 250 MW at Rosalia on the Benewah-Shawnee 230 kV line. New 230 kV would have to be constructed for 30 miles to Rosalia and a 230 kV switching station would also have to be built. The time to construct will be approximately 4 years.

Cost: Interconnection $852k/mile (total miles = 32 at 800 MVA capacity)

Transmission $0

Substation $8M

<u>**Annual O&M $200k**</u>

Total $35 million

400 MW: It is expected to integrate 400 MW at Westside, the existing 115 kV would have to be rebuilt 230/115 double circuit back to the main BPA corridor. Then to connect at Westside additional 230 kV would be constructed utilizing BPA's transmission or by building new 230 kV. The time to construct will be approximately 4 years.

Cost: Interconnection $994k/mile (total miles = 56 at 800 MVA capacity)

Transmission $796k/mile (total miles = 25 at 800 MVA capacity)

Substation $2M

<u>**Annual O&M $400k**</u>

Total $80 million (approximate)

It is expected to integrate 400 MW at Rosalia on the Benewah-Shawnee 230kV line. New 230 kV would have to be constructed for 30 miles to Rosalia and a 230kV switching station would also have to be built. The time to construct will be approximately 4 years.

Cost: Interconnection $852/mile (total miles = 30 at 800 MVA capacity)

Transmission $442/mile (total miles = 30 at 800 MVA capacity)

Substation $8M

<u>**Annual O&M $300k**</u>

Total $50 million (approximate)

Spokane/Coeur d'Alene

There are a number of 230 kV stations and transmission lines in the Spokane/Coeur d'Alene area that make good generation interconnection points. Westside, Beacon, Bell, Boulder, and Rathdrum are all large stations with 230/115 kV transformation in the Spokane/Coeur d'Alene area. However, with integrating large generation in this area the greatest concern is the thermal loading on the underlying 115 kV system. Without knowing a specific spot that generation would want to be brought on all of the 115 kV work is an approximation. The Spokane/Coeur d'Alene area covers too much land to be any more specific on costs. Any added generation greater than 250 MW will simply further increase costs and regional impacts.

The following estimates might be reasonable for integration of energy at this site:

50 MW: It is expected to integrate 50 MW in the Spokane/Coeur d'Alene, can be done with little (<10 mi.) or no 115 kV reconductor work. The time to construct will be approximately 1 year.

Cost: Interconnection $1M

Transmission $184k/mile (total miles = 10 at 140 MVA capacity)

Substation $0

<u>Annual O&M $44k</u>

Total $3 million

100 MW: It is expected to integrate 100 MW in the Spokane/Coeur d'Alene, can be done with little (<30 mi.) of 115 kV reinforcement. The time to construct will be approximately 2 year.

Cost: Interconnection $1M

Transmission $184k/mile (total miles = 30 at 140 MVA capacity)

Substation $0

<u>Annual O&M $200k</u>

Total $7 million

>250 MW: It is expected to integrate >250 MW in the Spokane/Coeur d'Alene that generation of this size would be connected at the 230 kV level. Adding generation in this range would require extensive 115 kV reconductoring. The radial operation of Avista's 115 kV lines in Spokane and Coeur d'Alene or generation dropping for 230 kV outages would probably be needed. Additional 230 kV work would likely be needed depending on the interconnection point. The time to construct will be approximately 5 year.

Cost: Interconnection $1M

Transmission $184k/mile (total miles = 50+ at 140 MVA capacity)

Transmission $442k/mile (total miles = 30+ at 800 MVA capacity)

Substation $8M

<u>Annual O&M $400k</u>

Total $32 to $500 million (at higher levels of generation)

Mica Peak

The present transmission system around Mica Peak is fairly close to existing Avista 115 kV lines with available capacity.

The following estimates might be reasonable for integration of energy at this site:

50 MW: It is expected to integrate 50 MW at the Post Falls substation would require 6 miles of 115kV line and a new breaker position at Post Falls. The time to construct will be approximately 1 year.

Cost: Interconnection $426k/mile (total miles = 6 at 140 MVA capacity)

Transmission $0

Substation $1M

<u>Annual O&M $24k</u>

Total $4 million

Clark Fork Hydro Upgrades

The present transmission system in the area consists of both Avista and BPA 230kV lines that served to integrate the Western Montana Hydro (WMH) projects. The WMH refers to the four major hydroelectric plants operated in northwestern Montana and on the northern Montana-Idaho border. These include the federally operated Libby and Hungry Horse projects and the Cabinet Gorge and Noxon Rapids (Clark Fork hydro) projects operated by Avista. After Avista's completion of its planned upgrades to Cabinet Gorge and Noxon Rapids, these projects will have peak generation capacities of 268 MW and 558 MW, respectively, for a combined capacity of 826 MW.

Avista and BPA have executed a WMH operating agreement that provides for a 50-50 allocation of a 1700 MW WMH operating limit between the federal projects and Avista projects. This agreement relates to Avista-LSE's ability to operate its Clark Fork hydro projects for service to Avista's bundled retail native load customers. After completion of Avista's planned generation upgrades, Avista's total Clark Fork hydro generation capacity will be at 826 MW, below Avista's WMH operational allocation of 850 MW. Dependent upon continuation of the operational allocation of WMH hydro capability between Avista and BPA, no new transmission upgrades will be needed for Avista to integrate the planned upgrades of its Clark Fork hydro projects.

Dayton, Washington

The present transmission system serving the Dayton, Washington area is a single 230 kV line with dual ownership by Avista and PacifiCorp. There is also a 115 kV line in the area owned by BPA and a 69 kV line owned by PacifiCorp.

The following estimates might be reasonable for integration of energy at this site:

50 MW: It is expected to integrate 50 MW on the Dry Creek-Walla Walla 230 kV line at the ownership change between Avista and PacifiCorp, a new switching station and a 15 mile 230 kV line to this location would be necessary. At present this line lacks capacity to support 50 MW due to current contractual obligations. Therefore, the Dry Creek-Walla Walla 230 kV line would need to be reconductored to support additional capacity. The time to construct will be approximately 4 years.

Cost: Interconnection $746k/mile (total miles = 15 at 450 MVA capacity)

Transmission $442k/mile (total miles = 28.5 at 800 MVA capacity)

Substation $8M

Annual O&M $200k

Total $32M

100 MW: It is expected to integrate 100 MW on the Dry Creek-Walla Walla 230 kV line at the ownership change between Avista and PacifiCorp, a new switching station and a 15 mile 230 kV line to this location would be necessary. At present this line lacks capacity to support 100 MW due to current contractual obligations.

The Dry Creek-Walla Walla 230 kV line would need to be reconductored to support additional capacity. The time to construct will be approximately 4 years.

Cost: Interconnection $746k/mile (total miles = 15 at 450 MVA capacity)

Transmission $442k/mile (total miles = 28.5 at 800 MVA capacity)

Substation $8M

Annual O&M $200k

Total $32 million

Note that there may be a potential real time solution using real time thermal monitoring (using the Valley Group's Cat-1 or other similar technology).

Reardan, Washington

The present transmission system serving the Reardan, Washington area is a low capacity 115 kV line.

The following estimates might be reasonable for integration of energy at this site:

50 MW: It is expected that to integrate 50 MW at the Reardan substation, at minimum the 115kV line from Garden Springs to Sunset would need to be reconductored along with a new air switch at Westside on the Nine Mile line. The time to construct will be approximately 1 year.

Cost: Interconnection $1.4M

Transmission $184k/mile (total miles = 2.5 at 140 MVA capacity)

Substation $100k

Annual O&M $14k

Total $2 million

100 MW: It is expected that to integrate 100 MW at the Reardan substation, at minimum the 115 kV line from Reardan to Devils Gap would need to be reconductored and a new line out of Reardan would be necessary. The time to construct will be approximately 2 years.

Cost: Interconnection $1.4M

Transmission $184k/mile (total miles = 14 at 140 MVA capacity)

Transmission $426k/mile (total miles = 20 at 140 MVA capacity)

Substation $0

Annual O&M $200k

Total $13 million

Lind, Washington

The present transmission system serving the Lind, Washington, area is a low capacity 115 kV line and two 115 kV lines that are operated in a radial configuration.

The following estimates might be reasonable for integration of energy at this site:

50 MW: It is expected that to integrate 50 MW at the Lind substation, very little new transmission would be required. The time to construct will be approximately 1 year.

Cost: Interconnection $1.4M

Transmission $0

Substation $0

Annual O&M $10k

Total $1.5 million

100 MW: It is expected that to integrate 100 MW at the Lind substation, at minimum the 115kV line from Lind to Warden would need to be reconductored. The time to construct will be approximately 1 year.

Cost: Interconnection $1.4M

Transmission $184k/mile (total miles = 22 at 140 MVA capacity)

Substation $0

Annual O&M $100k

Total $6 million

Othello, Washington

The present transmission system serving the Othello, Washington, area is low capacity 115 kV lines.

The following estimates might be reasonable for integration of energy at this site:

50 MW: It is expected that to integrate 50 MW at the Othello substation, very little new transmission would be required. The time to construct will be approximately 1 year.

Cost: Interconnection $1.4M

Transmission $0

Substation $0

Annual O&M $10k

Total $1.5 million

Colfax, Washington

The present transmission system serving the Colfax, Washington, area is a low capacity 115 kV line.

The following estimates might be reasonable for integration of energy at this site:

50 MW: It is expected that to integrate 50 MW at the East Colfax substation, very little new transmission would be required. The time to construct will be approximately 1 year.

Cost: Interconnection $1.4M

Transmission $0

Substation $0

Annual O&M $10k

Total $1.5 million

Lancaster Generating Facility Power Purchase Agreement Evaluation Overview

April 11, 2007

Introduction & Summary

In early 2007 Energy Resources was asked to determine if Avista utilities would benefit from acquisition of the 275 MW Lancaster Generating Facility Power Purchase Agreement ("Power Purchase Agreement" or "Lancaster") then owned by Avista Energy.

The plant is an option to the utility as part of Avista Corporation's proposed sale of Avista Energy to Coral Energy. The Power Purchase Agreement is essentially a "tolling arrangement" whereby the Lessee delivers natural gas to the plant and receives the capacity and energy output in exchange for paying the Lessor fixed and variable Power Purchase Agreement payments. The Power Purchase Agreement expires on October 31, 2026.

Analyses based on the Avista IRP and Northwest Power and Conservation Council's ("NPCC") planning assumptions indicate that the acquisition of an existing gas-fired combined-cycle turbine (CCCT) is potentially more valuable than the construction of a new gas-fired plant. Avista's 2007 Draft IRP had identified a CCCT as a preferred resource. The analysis further shows that the Power Purchase Agreement will benefit Avista when compared both to new and other existing CCCT plants that were recently transacted or constructed in the Pacific Northwest region.

Assumptions

Assumptions in a number of different areas are necessary to complete the Lancaster Power Purchase Agreement comparison, including alternative resources the company might consider, natural gas supply, taxes and transportation, electricity transmission, plant operating and maintenance costs, end-of-life plant values, and rates for inflation and discounting. Because the comparative resources are all newer-vintage natural gas-fired CCCTs with similar heat rate and operating costs, natural gas supply and transportation costs and operation costs were assumed to be the same for each plant; therefore, these costs were not explicitly modeled in the comparative evaluation. One benefit not modeled is the fact that the Power Purchase Agreement places some of the risk of forced outages and maintenance on the Lessor, removing some of this risk from Avista and its customers.

A brief discussion of the modeling assumptions is provided below.

Power Purchase Agreement Alternatives

Avista's 2007 IRP process provides guidance on the resources available to serve customer needs. The IRP process shows that the Company needs up to 350 MW of gas-fired generation along with other renewable generation technologies and conservation.

Given the significant component of gas-fired CCCT resources in the 2007 IRP, the Power Purchase Agreement evaluation focuses on comparisons with other potentially available CCCT options. The 2007 IRP estimates new, or "greenfield", CCCT plant costs at $786/kW in 2007 dollars, or approximately $850/kW in inflation-adjusted 2010 dollars. This later figure is used to represent the cost of a new plant for the analysis.

The Power Purchase Agreement is also compared to an estimated cost of an existing, or "brownfield", CCCT plant in the Northwest. Table 1 is a list of Northwest CCCT plants. Plants not owned by regional utilities are highlighted.

Table 1 – Northwest CCCT Plants

Name	*Utility*	*Owner*	*Capacity (MW)*
Coyote Springs 2	Avista	Utility	287
Frederickson	Puget	Utility	256
Big Hanaford	TransAlta	Non-Utility	322
River Road 1	Clark PUD	Utility	248
Hermiston Power Project	Calpine	Non-Utility	648
Coyote Springs 1	PGE	Utility	246
Goldendale Energy Center	Puget	Utility	240
Port Westward Power Plant	PGE	Utility	400
Rathdrum Power Project	Cogentrix	Non-Utility	276
Chehalis Generation Facility	Tractebel	Non-Utility	550
Hermiston Cogen 1	PacifiCorp	Utility	486
Klamath Cogeneration	City of Klamath Falls	Non-Utility	150
Encogen 1	Puget	Utility	170
Total Non-Utility (MW)			**1,946**

As shown, total non-utility CCCT plant capacity is under 2,000 MW, including the Lancaster Generation Facility. Besides Lancaster, only 4 plants are not owned by a utility today. To Avista's knowledge, none of the plants are for sale. Two are larger than the amounts recommended by the IRP process.

Acquiring another brownfield CCCT plant is therefore considered unlikely; however, Avista chose to compare the Power Purchase Agreement economics as if brownfield options were available to it. The following table provides a summary of recently-completed CCCT transactions. The "2010 Price" escalates each transaction for inflation to 2010 dollars assuming 3% annual inflation.

Table 2 – Recent Pacific Northwest CCCT Plant Sales ($/kW)

Plant Name	Buyer	Purchase Year	Purchase Price	2010 Price
Frederickson	Puget Sound Energy	2003	590	726
Coyote Springs 2	Avista	2004	446	533
Goldendale	Puget Sound Energy	2007	480	525

Given the 2010 price range in Table 2, the company selected for this analysis two cost estimates for brownfield sites: $550/kW and $500/kW.

<u>Electric Transportation (Transmission)</u>

The Lancaster Generation Facility is located in Avista's Northern Idaho service territory. It presently is interconnected into the Bonneville Power Administration ("BPA") control area. Avista plans to explore the option to directly interconnect the Lancaster plant to its transmission system to avoid most of the BPA firm transmission costs. The interconnection cost is estimated at $3 million.

Along with the Power Purchase Agreement the company will receive a long-term firm transmission path from the Lancaster point of receipt to John Day. Under the assumption that Avista will be able to interconnect Lancaster directly to its transmission system, it will not require the BPA transmission during most of the year. The BPA transmission can therefore be used to better optimize Avista's resource operations or be sold to 3rd parties wanting to move energy across the "West of Hatwai" constrained path. The analysis assumes that only 25% of the existing firm transmission contract cost is not recovered through re-marketing of the BPA transmission or otherwise optimized through other power transactions.

Greenfield and brownfield plants are assumed to require a transmission contract with the Bonneville Power Administration for their entire operating capacity, as such a path would be necessary to move electrical energy from their respective locations to Avista's service territory.

In the event Avista does not interconnect the Lancaster plant directly to its system, it would not incur the $3 million interconnection cost but would directly utilize BPA transmission. In a worst case scenario where none of the BPA transmission was re-marketed or otherwise optimized, the cost of the Power Purchase Agreement would rise by approximately $66 million on a present value basis. However, since Lancaster is a dispatchable plant, it is reasonable to assume that at least a portion of the BPA transmission costs could be recovered. A 25% cost recovery is a reasonable assumption and represents a cost of approximately $42 million on a present value basis.

Power Purchase Agreement and Capital Recovery Payments

The Power Purchase Agreement includes a known set of payments. Brownfield and Greenfield options would be owned by Avista and capital recovery would occur over a defined schedule. The analysis uses the 2007 IRP capital recovery factors applied to all owned plant options.

Ending Value

The Lancaster Generation Facility Power Purchase Agreement expires on October 31, 2026. Avista will retain no value from the plant after expiration. To level the playing field with ownership options where residual, or ending, value would apply; all ownership option comparisons (i.e., all except the Lancaster plant) assume an ending value. For brownfield comparisons, the ending value is 10% of what a new plant would cost in 2027, in line with industry estimates. A greenfield plant ownership option would have a longer life due to its being constructed as much as ten years later than the brownfield and Lancaster plants. The greenfield residual value equals the brownfield ending value *and* the present value of forecasted wholesale market values through the end of its 30-year economic life after 2026.

Scenarios

It is unclear at this time when the Lancaster plant will be made available to Avista. There is also uncertainty over when the company will be resource deficit because of changing load forecasts.

Avista Loads and Resources Deficiency

The value of a new resource depends on the utility's loads and resources balance. Where the company is long–i.e., resources exceed loads–the value is what can be generated through sales into the wholesale marketplace. When the company is short–i.e., loads exceed resources–it is reasonable to include not only the market value of energy, but also the capital recovery and other fixed costs associated with plant ownership. Both of these assumptions are consistent with the IRP methodology.

The analysis considers two starting deficiency dates: 2011 based on work performed in the 2007 IRP, and immediate based on regional work by the Northwest Power and Conservation Council (NPCC). The first load deficiency identified in the 2007 IRP process is in 2011. Loads, including a planning margin equal to 10% of peak day load and 90 MW for reduced resource capabilities due to river freeze ups and coal handling issues, are compared to expected peak-day resource capability. The planning margin approximates 15%.

The NPCC is leading an effort to better define the peak generating capability of the Northwest. The NPCC planning criteria, based on a cross-functional work effort including many Northwest utilities, is approximately 25% based on a 5% loss-of-load probability across the entire northwest electric system and loads. Though the criterion is not yet finalized, the reserve level has remained approximately the same throughout the work effort. To meet the NPCC target, each Northwest utility would need to own or control resources capable of generating at levels 25% greater than their expected peak load. Under this criterion, Avista is capacity deficient immediately.

Power Purchase Agreement Availability Date

Because Power Purchase Agreement negotiations with Coral Energy are ongoing, the company chose to evaluate the Power Purchase Agreement across three start dates: 2009, 2010, and 2011. In the greenfield and brownfield evaluations, the plants are assumed to begin in the actual year of resource deficiency where the Power Purchase Agreement begins on the start date irrespective of the load and resources balance. For example, in the scenario where the Power Purchase Agreement is transferred to Avista in 2009 and the IRP methodology identifies a 2011 deficit, Power Purchase Agreement costs and benefits begin in 2009. Brownfield and greenfield plants, however, are not brought into the mix until 2011. Because the analysis assumes that the sum of the fixed and variable costs of the Power Purchase Agreement exceed the value of power in the spot market, the early inclusion of the Power Purchase Agreement prior to the deficit year decreases its value relative to other options.

Results

The following summarizes the results of the analysis shown in Appendix 1 – Study Results:

- The Lancaster Power Purchase Agreement is lower cost than the greenfield plant being included in the Preferred Resource Strategy of the 2007 IRP. A greenfield project is the company's most realistic alternative to Lancaster for acquisition of a CCCT resource.
- The Lancaster Power Purchase Agreement is less expensive than either brownfield or greenfield plants under all cases where Avista carries reserve margins in line with the NPCC reserve requirements.
- The only scenarios where a brownfield CCCT was shown be more beneficial than the Lancaster Power Purchase Agreement was where the plant was transferred to Avista prior to 2010, or where such brownfield plant's purchase cost is below $550/kW.
- Transmission scenarios, where less than 75% of the BPA firm transmission cost might be recovered in the market, have the effect on reducing the positive values shown in Table 3. As stated earlier, the maximum impact is estimated to be approximately $66 million if none of

the BPA transmission is re-marketed or otherwise optimized. Because Lancaster is a dispatchable CCCT, it is reasonable to expect that some level of cost recovery, possibly up to 25%, will be achievable even in the case where the project is not interconnected to the Avista system and remains on the BPA transmission system. A 25% transmission cost recovery scenario adds approximately $42 million to the Power Purchase Agreement value (cost of Power Purchase Agreement). A greenfield plant continues to be more costly than the Lancaster Power Purchase Agreement in each of the three start date scenarios under this transmission circumstance.

In summary, the study found that in most scenarios the Power Purchase Agreement will have a positive value to customers. In all base cases the Lancaster Power Purchase Agreement provides a significant benefit relative to constructing a new greenfield plant. The 2010 start date showed a positive benefit to the Lancaster Power Purchase Agreement except in the case where Avista were to have an opportunity to acquire a brownfield plant at a cost below $550 per kilowatt. The Company is not aware of such a brownfield opportunity available in the marketplace at this time.

Table 3 – Study Results

	Alternative Start Dates of Avista Resource Deficiencies and Lancaster Plant Availability					
	IRP Reserves (~15%) – 2011 Deficit			NPCC Reserves (25%) – 2009 Deficit		
Option	2009-2026 ($millions)	2010-2026 ($millions)	2011-2026 ($millions)	2009-2026 ($millions)	2010-2026 ($millions)	2011-2026 ($millions)
Lancaster Lease Value						
Cost of Lease	275	271	266	275	271	266
Lease Alternatives						
Greenfield CCCT @ $850/kW	320	332	337	358	348	337
Brownfield CCCT @ $550/kW	267	275	286	308	293	286
Brownfield CCCT @ $500/kW	254	261	271	291	277	271
Lease Savings Versus						
Greenfield Savings	46	62	72	83	78	72
Brownfield Savings @ $550/kW	(8)	4	21	34	22	21
Brownfield Savings @ $500/kW	(21)	(10)	5	16	6	5

Assumptions:

1) greenfield CCCT assumption based on 2007 IRP/NPCC.
2) transmission for off-site CCCTs @ $2.25/kW-mo plus 1.9%; leased CCCT is 25% of off-site.
3) residual values for non-lease CCCTs assumed to be 10% of installed cost @ end of life, plus net value against market for remainder of "economic life" from 2007 IRP. For greenfield, residual value is ~$220 million; for brownfield the residual value is ~$36 million. The difference being attributed to 10 years of additional life for the greenfield project.
4) greenfield plants assume 30-year recovery and depreciation; brownfield 20 years.
5) general escalation assumptions of 3% per year.
6) nominal discount rate of 7.41% (WA after tax rate)
7) values prior to resource deficiency use market value from 2007 IRP runs; after deficiency, fully allocated cost of new plant.

Independent Valuation of
Lancaster Facility Tolling Agreement

October 30, 2007

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Executive Summary

Thorndike Landing, LLC ("Thorndike Landing") was retained by Avista Corporation ("Avista") to perform an independent valuation of the tolling arrangement ("Toll") associated with the Lancaster generating facility, a 262 MW gas-fired combined cycle plant ("Facility") currently owned by a third party. The Toll will become available to the portfolio of Avista's regulated utility, Avista Utilities, Inc. as of January 1, 2010,

For this effort, Thorndike Landing looked at several different valuation metrics and perspectives to derive the valuation for the transaction contemplated by Avista. First, we performed a discounted cash flow ("DCF") analysis to determine the value of the Toll from the perspective of the Lessee under the terms of the Toll and taking into consideration all of the key factors for that agreement. Second, we performed a valuation of the Facility under a purchase scenario. For this valuation, we used the DCF method to value the Facility as of the valuation date (as more fully described herein) from the perspective of the owner without the Toll (i.e., assuming merchant operations). The approach and assumptions for this valuation were consistent with that used in valuing the Toll, except for factors that were clearly not applicable for a plant valuation versus a toll valuation (e.g., the useful life period was assumed to be 35 years versus the term of the Toll, the tolling payments were excluded, etc.).

The next valuation metric we employed was to identify a few select assets in the market and perform valuations of those similarly-situated plants. For this effort, Thorndike Landing performed valuations of the Goldendale facility as purchased by Puget Sound Energy earlier this year, the Coyote Springs 2 plant as currently owned by Avista Utilities and the Port Westward facility as being developed by Portland General. We also employed the DCF method to value these comparable facilities. As a final valuation reference check, Thorndike Landing reviewed transaction market activity to identify similar assets that have transacted and to assess the value of these assets and whether they were comparable to the contemplated transaction for the Toll. We recognize that this transaction – a toll versus an asset transaction – is fundamentally different than these comparables but these comparables served as an additional reference for market value.

Based on these four differing, yet complimentary, valuation perspectives Thorndike Landing has found that the Toll provides positive value to Avista and its customers (see Results and Conclusions section) and the value of the Lancaster facility appears consistent with—if not greater than—the value of other resources in that market.

Thorndike Landing also performed a review of Avista's analytical process and methodology to identify any potential shortcomings or areas that may be improved to provide it with a better, more comprehensive analytical process. Based on this review, we have found that Avista's analytical process and methodology is a very contemporary approach to analyzing resources. We have found that Avista's analytical process is sound and even surpasses processes used by many of their peers across the industry.

As part of this review, Thorndike Landing also reviewed Avista's analysis of the Toll to ensure both the methodology was appropriate and that the quality of the analytics was reasonable. We identified two areas in the Toll-specific analysis that warranted attention, but found neither of concern or to have a material impact on the overall results.

Objective and Purpose

Thorndike Landing was retained by Avista to perform an independent valuation of the Toll associated with the Lancaster generating facility currently owned by a third party. Avista has the opportunity to add this toll to the portfolio of its regulated utility. Avista Utilities has performed its own valuation of the Toll. The determination of this independent valuation performed by Thorndike Landing, as set forth in this report, will be relied upon by Avista in connection with its efforts to add the Toll to its regulated portfolio.

Thorndike Landing has performed several tasks to aid in determining the value of the Toll to Avista and its customers. First, we have reviewed information and data provided to us by Avista regarding the Facility, its financial parameters, its operations, and the Toll itself. Next, we have used the DCF approach to assess the value of the Toll and we have also performed a valuation of the Facility itself for comparison purposes. Next, we have identified transaction values for other generating assets that have sold in this market to establish a set of market comparables and their values for comparison purposes. Lastly, we have taken this comparables assessment further than is customarily done in these situations and have performed valuations of relevant generating assets that have been constructed or have transacted recently in this market. Next, we reviewed Avista's analytical approach to determine if there were any deficiencies and any areas that could be improved. Lastly, we prepared this report describing the salient assumptions used, our approach and our findings regarding whether the Toll is of sufficient value to Avista and its customers to warrant being included in its regulated generating portfolio.

For this effort, Avista has provided Thorndike Landing with specific instructions regarding this effort: (a) we are to use the analytical methods currently and customarily used in the market for valuation purposes; (b) we are to value the Toll as an independent, third-party would value it; (c) we are to remain independent at all times and are to use our best judgment regarding assumptions to be used; and (d) when reviewing their analytical process we are to remain independent and are to offer all constructive feedback with the goal of improving this process in every way possible.

The remainder of this report describes the approach Thorndike Landing has used in determining the value of the Toll, the salient assumptions used, our assessment of Avista's analytical process and our results and conclusions.

Description of Facility and Tolling Agreement

The Facility is a 262 MW, gas fired combined cycle generation facility located on a 15-acre site approximately 2.5 miles from Rathdrum, Idaho.

Table 1: Facility Characteristics

Category	Description
Location	Rathdrum, ID
Capacity	262 megawatts
Primary fuel	Gas
In-service date	September 2001
Turbine manufacturer, type	GE 7FA
Employees	20
Average net heat rate (2006)	6,925 btu/kWh
Average equivalent availability (2006)	92.9%

Power offtake was originally contracted to Avista Energy under a long-term tolling agreement (the "Toll"). On July 1, 2007 the Toll was assigned to an unrelated third party ("Seller" or "Lessor"). The Toll will become available to Avista Utilities, Inc. as of January 1, 2010, or the "Valuation Date" for purposes of our analysis.

Under the terms of the Toll, Avista Utilities ("Purchaser" or "Lessee") would have call rights to energy and capacity from the Facility over the term of the agreement. As consideration for those rights, Avista would pay the Seller a capacity charge and an energy charge as described in more detail below. Avista would also remain responsible for gas supply, as well as electric transmission. Specific key terms of the tolling agreement include the following:

- Term: For purposes of our analysis, the starting date will be January 1, 2010. The Toll expires on October 31, 2026.
- Capacity:
    - Includes both "standard" capacity (baseload) and "supplemental" capacity (duct-fired)
- Payments:
    - Capacity payment comprised of a capital charge and an O&M charge
        - Capital charge: $4.352/kW-month in 1998 dollars, escalated at 1% per year

        - Operations and Maintenance (O&M) payment: $1.302/kW-month in 1998 dollars, escalated with a specified annual inflation measure thereafter
    - Energy charge: $1.463 per MWh in 1998 dollars, escalated with a specified annual inflation measure thereafter
    - Start payment: $6,000 per start for starts greater than 100 in a contract year.
- Other key terms:
    - Availability: Seller has a 97% availability target. Capacity payments related to periods with realized availability less than 97% are reduced on a pro rata basis.
    - Guaranteed heat rate was specified

The facility continues to be managed under an O&M agreement with a third party. This agreement is effective through September 2026.

Electric transmission service is available through an agreement with Bonneville Power Administration ("BPA"). Key terms of this agreement are as follows:

- Term: July 1, 2001 through June 30, 2026
- Point of delivery: John Day
- Pricing is consistent with that under the published BPA tariff
- Transmission rights under the BPA agreement will transfer to Avista Utilities January 1, 2010

Thorndike Landing Approach

This section of the report describes the analytical methods used to perform the various valuations and assessments conducted for this effort. The results of these analyses are presented in the Results and Conclusions section of this report.

For this effort, we looked at several different perspectives to derive a valuation for the transaction contemplated by Avista. First, we performed a valuation of the Toll, taking into consideration all of the key factors for that agreement. Second, we performed a valuation of the Facility under a purchase scenario. Next, we identified comparable assets in the Northwest market and performed valuations of those to get a sense as to what the values of those assets are. Lastly, we reviewed comparable transactions in the generation market and assessed the average values of those deals in the most appropriate market.

Valuation of the Toll

In order to value the Toll, Thorndike Landing developed a discounted cash flow ("DCF") analysis of the Lancaster facility from the perspective of the Lessee under the terms of the toll. For purposes of our valuation, the applicable valuation date is January 1, 2010 ("Valuation Date"). As noted above, this is the date at which Avista would expect to assume the rights and obligations under the toll. The DCF analysis is based on projections of the Lessee's forecasted annual after-tax free cash flows through the end of the lease term, discounted at Avista's after-tax weighted average cost of capital. The cash flows accruing to or paid by the Lessee would include all margins from sales of energy and capacity, lease payments, and operating costs expected to be borne by the Lessee (and not the Lessor/Seller) under the terms of the toll. Our approach to forecasting the components of free cash flows and the related key assumptions are discussed below.

General assumptions

- Valuation Date: January 1, 2010
- Term of analysis: January 1, 2010 – October 31, 2026
- Capacity: Average annual plant capacity was assumed to be 262 MW, of which 25 MW was assumed to be related to duct-fired peaking capacity. The total capacity was based on the average (summer / winter) capacity as reported by the Energy Information Administration ("EIA")
- Forced outage rate: 5%

Energy margins and capacity revenues

Energy margins and capacity revenues were forecasted using Thorndike Landing's proprietary Integrated Energy and Capacity Model ("IECM"), a production cost model which dispatches regional resources (including the Facility) against forecasted hourly load on an economic basis to derive market clearing energy pricing and unit dispatch / margins. The IECM also derives regional capacity values based on: (a) supply and demand dynamics, (b) new build economics, and (c) derived energy margins. The Facility revenues and margins derived from IECM are based on merchant (uncontracted) dispatch and are net of variable production costs including:

- Delivered gas costs including costs associated with gas commodity, delivery costs (excluding fixed gas transportation), gas transportation losses, fuel taxes (if any), etc.
- SO_2 costs
- CO_2 costs

Note that our analysis included three pricing scenarios for purposes of valuing the toll: base, low and high. See additional discussion of IECM methodology, assumptions and results in the Appendix.

Toll payments

Payments made under the Toll for capacity, energy and start charges were based on the terms as described in the Description of the Facility and Tolling Agreement section above. Additionally, escalation rates used for payments under the toll were as follows:

- Capital charge: 1% per the terms of the agreement
- O&M and Energy charges:
    - From 1998 to 2007: 2.4%. This was derived from our review of the associated referenced Gross Domestic Product Implicit Price Deflator.
    - From 2007 through 2026: 2.5%

Gas costs

Modeled gas costs include both fixed and variable components, as requested by Avista gas personnel on staff, to derive our forecasts for both these fixed and variable components.

- Fixed gas transportation costs: According to Avista, gas for the Facility is sourced from 2 delivery points—Alberta and Malin. As such, there are gas transportation contracts for both of these paths.
    - From Alberta:
        - 27,841 GJ per day through October 31, 2017

        - Price: $.187 per mmbtu (in 2007 dollars)
    - From Malin:
        - 26,388 GJ per day through October 31, 2017
        - Price: $.26 per mmbtu (2007 $)

  Note that the total gas transportation exceeds the total gas needs of the plant when operating at full capacity by approximately 20% (approximately $550,000 in 2007). It appears that the additional capacity was obtained to allow the Facility to arbitrage between the gas supply points. Note that we did not include the cost for the excess gas supply, which was assumed to have been remarketed or otherwise utilized for utility service at cost. We also did not include the offsetting the arbitrage opportunity between Alberta and Malin hubs in our analysis. In order to estimate the impact of this arbitrage opportunity, we analyzed gas data for the Malin and Alberta hubs from the prior 3 years. Given the gas transportation limitations for both hubs (as shown above) and assuming perfect optimization of pricing between the hubs, the blended gas price for Lancaster would be approximately $.25/mmbtu (1.9%) lower than pricing at the Alberta hub alone. Further, note that it would also be possible for Avista to derive additional value from monetizing gas transportation for periods in which the Facility is down either for maintenance or for economic reasons. If the gas transportation necessary to meet daily gas requirements could be remarketed or otherwise utilized at cost, this would represent an additional value of approximately $9,000 pre-tax per day ($6,000 after-tax).

- Variable gas costs: (these are included in the energy margins modeled by the IECM)
    - Gas commodity: Priced at Alberta hub
    - Delivery costs:
        - Commodity fee: $.01 per mmbtu
        - Fuel transportation fee: 2.03%
    - Gas taxes: None for the Lancaster Facility. Unlike the state of Washington, Idaho does not currently have such a tax. For those comparable facilities located in the state of Washington, a fuel tax of 3.852% was applied. Based on our analysis, the impact of a 3.852% fuel tax on the value of the Toll would be approximately $26 million.

Both fixed and variable costs were escalated at an annual rate of 1.5%

Electric transmission

The Facility currently takes electric transmission services under a services agreement with BPA, under the BPA transmission tariff. Refer to tariff rates under the Description of Facility and Tolling Agreement above. However, Avista estimates that it could directly interconnect the Facility to its own system at a total cost of approximately $3 million, thereby negating the need to take service through BPA. For purposes of our analysis, we have assumed that Avista performs the interconnection work. The transmission agreement with BPA in this case will be utilized in other ways. We have assumed that a portion (75%) of the electric transmission capacity under the BPA agreement is remarketed at cost—or otherwise used for utility load service—and therefore not borne by the Facility / Lessee. We note that the utility's customers avoid BPA's charge for electric losses of 1.9% once the facility is interconnected directly with Avista's system. As compared to an otherwise identical unit that would incur this cost, the Facility reflects higher margins (1.9% of market clearing prices) in all hours when both facilities would be dispatched. In addition, the Facility would also be dispatched in additional (lower margin) hours relative to its peer when it is at—or close to—the margin. Based on our analysis, the value of a 1.9% loss factor on the value of the Toll is approximately $12.5 million.

Tax Depreciation

Capital expenditures—specifically the interconnection cost—were depreciated based on 20-year MACRS.

Taxes

Combined state and federal tax rate was assumed to be 39.94%

Discount rate

After-tax free cash flows were discounted based on Avista’s after-tax weighted average cost of capital of 7.41%.

Costs Associated with Imputed Debt

Rating agencies generally consider long-term power purchase contracts to be equivalent in some regards to long-term debt. As such, they impute a value for debt that they apply to the power purchaser’s balance sheet. This imputed debt places downward pressure on the credit quality of the “borrower” and upward pressure on financing costs. In order to take into account the costs associated with the imputed debt, we included a cost of equity that would be necessary to neutralize the reduction in credit quality from the imputed debt.

Rating agencies have differing methodologies for imputing debt. For purposes of our analysis, we have utilized the process employed by Standard & Poor’s. The calculation begins with the determination of the fixed obligations associated with the demand payment. This payment stream is then discounted at the utility's average cost of debt. A risk factor is then applied to the net present value of the stream of fixed obligations to arrive at the amount of imputed debt.

The incremental cost applied to the Toll is based on the amount of equity that would need to be issued to maintain the utility's existing capital structure. The annual cost is then based on the utility's cost of equity applied to the calculated additional equity required.

Valuation of the Lancaster Facility

As a reference check, we also performed a valuation of the Facility as of the Valuation Date from the perspective of the owner without the toll—in other words, the value of the Facility assuming merchant dispatch. For this effort, we used the discounted cash flow ("DCF") method. The approach and assumptions used for this analysis were largely consistent with those of the analysis of the Toll above. Key differences include the following:

- Forecasting period / useful life. The facility was assumed to have a useful life of 35 years (through 2036). The value of the cash flows accruing to the project over its useful life were calculated as follows:
  - Jan. 1, 2010 – Dec. 31, 2030: Annual cash flows modeled through the use of IECM forecasting model.
  - Jan. 1, 2031 – Dec. 31, 2036 (end of useful life): Annual free cash flows assumed to be consistent with IECM terminal year (2030).
  - Residual value (post-2036): Assumed to be $0. Implicitly, the value of the site and associated scrap value of the equipment, etc. are assumed to be equal to the cost of dismantlement and any necessary site remediation.
- Tolling payments: By definition, excluded from this analysis
- O&M, including Major Maintenance – Based on estimated actual charges expected to be incurred for the Facility (not prescribed O&M fee per the terms of the Toll).
- Property taxes and insurance – Projected costs were included. In accordance with the terms of the Toll, these costs had previously been excluded from the Toll valuation.
- Tax depreciation: Based on both the historical construction cost of the Facility as well as additional capital (interconnection, major maintenance). The implicit assumption is that ownership of the Facility would be transferred via a purchase of the third party's equity (e.g., a stock purchase) and not a purchase of the underlying assets themselves (e.g., an asset purchase).

Valuation of Select Assets Transacted in Market

Thorndike Landing performed a valuation analysis for a few selected assets that compete against the Facility within the local or regional marketplace. Specifically, we valued the Goldendale facility as purchased by Puget Sound Energy earlier this year, the Coyote Springs 2 as owned by Avista Utilities and the Port Westward facility as being developed by Portland General. Given that these assets were not for sale, this exercise was intended to merely assess what the potential values of these assets would be *if* they were to transact and, hence, be available to Avista instead of the Toll.

For this assessment, we used the same DCF approach and general assumptions as outlined above.

Transaction Market Comparables

As a final reference check, we have also reviewed transaction market activity to identify similar assets that have transacted and to assess the value of these assets and whether they were comparable to the contemplated transaction for the Toll. We recognize that this transaction – a toll versus an asset transaction – is fundamentally different than these comparables; thus while this information has been reviewed as yet another reference point it has not been relied upon extensively to determine our conclusions. There are several factors to consider when reviewing and applying comparable transactions as a reference for a particular transaction: (a) similar fuel and technology type facilities; (b) salient attributes of the situation, such as whether the asset has an off-take agreement for the output, etc., if known; (c) geography and, specifically, the market the asset competes within; and (d) the period in which the transaction was executed.

For the first factor, it is important to filter the information and data and isolate those transactions that were for assets of a similar fuel and technology type; in this case gas-fired combined-cycle facilities. Depending on the number of transactions available for comparison purposes, occasionally portfolios of assets can also be applied if that portfolio is largely of a similar fuel and technology type. There is no set parameter or threshold of how many assets in the portfolio are similar or what percentage of the portfolio's capacity is similar, but it is generally acceptable to use a portfolio that is nearly all of similar fuel and technology type. Conversely, if there are a sufficient number of single-asset transactions those are generally preferred as a comparison set.

The second factor to consider is whether there exists any extenuating circumstances or attributes of a given transaction. The clearest example would be if an asset had an off-take agreement for a portion or all of its output. Depending on the prices and terms of that agreement (i.e., higher-than-market pricing vs.

lower-than-market pricing), the value of the transaction can be skewed. Specifically, if an asset had an off-take agreement that had pricing that was significantly greater than current market views, the value of that asset (including the contract) to a buyer would be greater than if it were a merchant facility. These details are not always known.

The third factor to consider when selecting a comparable set of transactions is geography. This geographical parameter is most easily identified by power pool or market (e.g., PJM, ERCOT, etc.). In this case, the specific market is less defined as the Toll is with a project in WECC which is a large control area versus a tightly-managed ISO as in other markets.

The fourth factor to consider when selecting a comparable set of transactions is the timing or era of the transactions to be included in the comparison set. Again, this is largely driven by the number of transactions available and there is no specific rule or threshold to use. It is common to use a term of between 18 and 24 months prior to the assessment if there is sufficient data and transactions available. This period is based on the premise that fundamental drivers to transactions (i.e., fuel prices and trends, credit markets, etc.) remain consistent for a period of time but do eventually change. As these fundamentals change, so do the resulting transaction activity and the values in this market. Lastly, if the number of transactions or data for those transactions is limited, it is common to use a period of up to three years to gauge comparable transactions.

During the past few years there have been several transactions that would be considered comparable to this proposed deal; again, using the general aforementioned criteria of similar types of plant, market, etc. Below is a summary of the publicly-available transactions that have occurred in this market during this three year period.

Date Announced	*Asset(s)*	*State(s)*	*Fuel*	*Type*	*MW Xfer*	*Seller*	*Buyer*	*Total Price (MM$)*	*Value ($/kW)*
12/17/2004	Coyote Sptings 2 (50%)	OR	Gas	CC	140	Mirant	Avista	$63	$446
5/18/2005	La Paloma	CA	Gas	CC	1022	Citibank lender consortium	Complete Energy Partners	$610	$597
5/19/2005	El Dorado (50%)	NV	Gas	CC	240	Reliant	Sierra Pacific Resources	$132	$550
6/21/2005	Silverhawk	NV	Gas	CC	427.5	Pinnacle West	Nevada Power	$208	$487
5/11/2006	Griffith	AZ	Gas	CC	300	PPL	LS Power	$115	$383
2/7/2007	Goldendale	WA	Gas	CC	250	Calpine	Puget Sound Energy	$120	$480
9/13/2007	Klamath Falls cogeneration	OR	Gas	CC cogen	506	City of Klamath Falls	PPM	$290	$573

As shown, during this period, there have been seven transactions averaging $533/kW. During this same period, there have been approximately 25 similar transactions executed throughout the remainder of the U.S., resulting in an average value of $465/kW. The relatively small divergence in these numbers is driven by several factors, including location/market, whether there exists an off-take agreement and, if so, what term exists for the contract, each specific buyer's view to commodity prices, cost of capital, etc.

It may be more appropriate to utilize a shorter period of time to assess comparable transactions, given that there has been a fairly significant change in several factors during the past three years in this sector; namely financing costs and commodity costs. The data set gets much smaller during this time and includes just the Puget acquisition of Goldendale and the PPM acquisition of the Klamath Falls cogeneration facility. The results of this period, however, remain very consistent with that of the three year period. Specifically, the average value of these transactions in this market is $542/kW as compared to $503/kW for the remainder of the U.S. during that same one-year period.

Other Considerations (Toll versus Ownership)

We have derived values for the Toll, the Facility and other indicators as described above. As mentioned, the Toll—although it conveys many of the rights and obligations of ownership—remains fundamentally different from actual ownership. Some of the primary considerations of a toll versus ownership include:

- Term of "ownership": Beyond the term of the Toll, the Lessee has no rights of ownership and the full value of any "terminal" or "residual" value reverts back to the Lessor/Seller.
- Operational risk: Under the provisions of the Toll, the Lessor/Seller has guaranteed a stipulated forced outage rate (approximately 3.0%), as well as a realized heat rate. Any costs associated with not meeting the operational parameters are borne entirely by the Lessor/Seller. For instance, in the event of an extended forced outage, the Lessee / Purchaser is entitled to replacement power (as defined) at the Lessor/Seller's cost, thereby mitigating such risk under a Toll arrangement.
- Limited risk of cost escalation: Cost escalation under the term of the Toll is limited to 1% annually for the capital charge and to an inflationary index for the O&M and energy rates. As such, there is little risk for cost overruns associated with regional or plant-specific impacts such as (local) labor costs, property taxes, insurance, etc. The Lessor/Seller bears the risk of such cost escalation in excess of economy-wide increases.
- Initial capital outlays: For purposes of our analysis, we derived the value of assuming the Toll as of the Valuation Date. We also determined the total value of certain facilities as of the Valuation Date. Note, however, in the case of the latter, we expressly excluded any capital costs associated with owners' acquisition of the facilities (e.g., construction costs, acquisition costs). Such initial capital outlays would be required to be made in the case of taking ownership but not in the case of the Toll since the tolling payments themselves is consideration for the use of the Facility over the Toll term.

Review of Avista Analytical Process

Thorndike Landing has performed a review of Avista's analytical process and methodology to identify any potential shortcomings or areas that may be improved to provide it with a better, more comprehensive analytical process. Our review consisted of a meeting and discussion session to review the overall methodology, ways in which they addressed contemporary issues (e.g., emissions, etc.), and a discussion surrounding the modeling platform and software used and how they interacted throughout the analytical process. We did not review the assumptions used by Avista in their analysis, other than to ensure that they had used current perspectives when deriving their assumptions. This section reviews Avista's current analytical approach, as well as the results of our review.

Overview of Avista Analytical Approach

Avista utilizes a dynamic and interactive modeling approach to resource planning and analyzing new resources for its system. This approach considers and analyzes both the Avista system, as well as its interaction with the broader Western Electricity Coordinating Council ("WECC"), analyzes and determines the risk associated with various scenarios and resources, and determines the optimal resource portfolio for its system based on power supply expenses, incremental capital costs and operating risk.

To accomplish this level of analytical rigor, Avista employs several distinct modeling platforms. First, it uses AURORAxmp to perform the market modeling, generate the capacity expansion plans and forecast electric market prices. Avista currently plans to a capacity planning target. Specifically, the scenarios within AURORAxmp introduce resources into the system to cover adverse or short load conditions; in essence, adding resources to exceed average needs. This philosophy ensures that resources are in the system and ready and available to meet system requirements in all but the most extreme conditions. This approach reflects sound utility planning in the market today, especially in WECC where many participants are still feeling the ramifications of the power crisis a few short years ago. The generic resources that the model calls upon for the capacity expansions include gas-fired combined-cycle combustion turbines, single-cycle combustion turbines, pulverized coal plants, integrated gasification combined-cycle coal plants with and without sequestration and wind turbines. This wide array of resources provides Avista's planning process with significant diversity when assessing various scenarios and the advantages and disadvantages of each with respect to both cost and risk.

Avista also uses AURORAxmp for risk assessment by performing stochastic analyses to determine the volatility of prices and potential resource valuations. Several salient assumptions are modeled stochastically, including hydroelectric conditions, natural gas prices, load conditions, wind production, forced outages of the facilities and the cost of emissions compliance. The Avista team reviews and determines the input assumptions for these and other variables into AURORAxmp and reviews the output of this model to ensure the results of logical and correct. By performing this stochastic analysis, Avista incorporates a measure of volatility for the projected electricity market prices and the resulting resource values to Avista and its customers.

Avista also uses another model, The Preferred Resource Strategy Model, or PRiSM, which is a proprietary model developed by Avista to aid it in selecting its preferred resource strategy. PRiSM quantifies the cost and risk associated with Avista's current resource portfolio and that of new potential resource additions. The PRiSM model uses a linear programming approach. This method enables complex decision-making in situations or processes that often have one- or multi-dimensional objectives, such as resource planning for both cost and reliability measures and goals. This model relies upon several factors to arrive at an optimal resource portfolio, including the base case assumptions as used in AURORAxmp, Avista load requirements for capacity and energy, capital costs associated with new resources, local transmission costs, and the market and cost values of each new and existing resource as modeled in AURORAxmp. PRiSM determines the preferred resource strategy based on several resource and portfolio metrics, including present value of the expected power expenses, incremental capital costs and operating risk to Avista.

Results of Thorndike Review

Thorndike Landing has reviewed Avista's analytical methodology and has found that Avista's analytical process and methodology is a very contemporary approach to analyzing resources. In fact, the utility industry in general has been slow, as compared to other industries, to adopt risk analysis into its process and it wasn't until the power and sector crises of 2001-02 that even some utilities began to incorporate risk into their processes. Today, we find that many utilities do factor risk analyses into their processes, but many still do not. Additionally, Avista's process is also grounded on sound resource planning using multiple scenarios and a robust vs. static process through which the company is able to assess multiple scenarios and resource portfolios, not just a single resource in isolation. For these reasons, we have found that Avista's analytical process is sound and even surpasses processes used by many of their peers across the industry. Therefore, we have not identified any area or aspect of its process generally for which we would suggest modification at this time. We do recommend, however, that Avista continue to review its methodology as it has for the past several years as analytical approaches continue to evolve with new techniques and information and Avista needs to maintain a current process given the challenges that inevitably lie ahead in our industry.

With respect to the analysis of the Lancaster Toll specifically, we likewise found the approach to be appropriate. However, we did identify items that warranted further consideration:

- *Exclusion of gas transportation costs*: We noted that gas transportation costs had been excluded from Avista's preliminary analysis of the Toll despite the fact that Avista would incur such costs after assumption of the Toll. Based on our discussions with Avista personnel, it appears that the internal assessment of gas transportation costs had not been completed as of the date of the preliminary analysis. We noted that these costs were excluded for both the Toll and the "offsystem CC" comparative analysis. As a result, any comparative results would only be impacted by any differences in gas transportation costs. Likewise, any upside from sourcing from dual gas hubs was also excluded from the Avista analysis.
- *Exclusion of costs associated with imputed debt:* Due to the fact that rating agencies impute debt associated with power purchase agreements such as the Toll, there is a cost associated with entering into such agreements. In connection with our analysis, we calculated such cost as described in the Valuation of the Toll section above. We noted that Avista did not include such costs in their analysis.

The items listed above do impact absolute values but did not have a material impact on relative values or overall conclusions. We noted no other material issues with Avista's process generally or its analysis of the Lancaster Toll specifically.

Results and Conclusions

Base results

Based on the aforementioned analyses, reviews and assessments, Thorndike Landing has determined the following base case results for the Toll, the Lancaster Facility and other comparative facilities.

Table 2: Summary of Toll Valuation Results

Description	Value	
	$000s	$/kW
NPV excluding imputed debt	$40,500	$155
Cost of imputed debt	(24,000)	(91)
NPV including imputed debt	16,500	64

The valuation of the Lancaster Facility is shown in Table 3 below.

Table 3: Summary of Lancaster Facility Ownership Valuation Results

Description	Value	
	$000s	$/kW
Lancaster	177,500	677

The valuation of the other similar combined cycle facilities in the region is shown in Table 4 below.

Table 4: Summary of Comparable Combined Cycle Ownership Valuation Results

Approach / Asset	Value	
	$000s	$/kW
DCF Analysis		
Coyote Springs 2	169,500	652
Port Westward	236,000	528
Goldendale	84,000	365
Transaction Comps Analysis	n/a	530

These values do not provide a direct comparison of each plant's (net) value to Avista. Instead, the values represent the value to Avista if it could assume the rights and obligations of the plant's current owner at no cost. For example, if the Goldendale plant were made available to Avista at no cost its value would be $84 million—or, in other words, Avista could pay up to $84 million for the plant. In the case of the Lancaster Toll, given our assumptions regarding the specific financial obligations and benefits as previously described in this report, the contract available to Avista is worth $16.5 million more than its costs. As such, Avista could pay up to $16.5 million for the contract and it would still represent a positive NPV (return) investment.

Sensitivities

As discussed above, we also ran high and low cases for the value of the Toll and for the Facility. These scenarios are derived by assuming distinct market drivers that are in the range of potential future market developments. As the subject of this report is a combined-cycle (CC) related product we focused on the two drivers that would produce relevant upside or downside to these types of plants. The core drivers we varied were (1) a doubling of assumed future CO_2 prices, and (2) the introduction of an additional 5,000 MW of combined-cycle capacity throughout WECC. Higher CO_2 prices result in a substantial relative benefit to CC's, while the CC overbuild simulated for the low case leads to a merchant margin depression. The results are as follows:

Table 5: Summary of Results

Description	Value - $000 ($/kW)	
	Toll	Facility
Base Case	$16,500 ($64)	$177,500 ($677)
Low Case	500 (2)	155,500 (594)
High Case	20,500 (78)	181,500 (692)

We also ran sensitivities around Avista's ability to re-market the excess electric transmission under the BPA contract that would be available after completion of the interconnection to Avista's system. For our base case values, we have assumed that 75% of the BPA transmission costs would be recouped through remarketing. However, given the materiality of the costs, we ran sensitivities based on the percentage of costs that would be recovered through third party sales.

Table 6: Lancaster Base Case Toll Values As a Function of BPA Transmission Costs Remarketed

% of Costs Remarketed	Value $000s	Value $/kW
0%	(7,500)	(29)
25%	500	2
33%	3,000	12
50%	8,500	33
67%	13,750	52
75%	16,500	64
100%	24,750	94

Conclusion

In conclusion, Thorndike Landing believes that the transaction for the Toll is reasonable and that the value Avista would remit for the Toll is reasonable and would result in a net benefit to Avista and its customers. Further, based on our analysis and assumptions, the value of the Lancaster Facility appears to be greater than that of other recently constructed or transacted facilities in the region. This greater value appears to be primarily driven by one or more of the following:

- Lower electric transmission costs
- Lower gas transportation costs
- Lower gas taxes (the state of Idaho has no fuel tax)
- Dual sourcing of fuel (Alberta/Malin vs. Sumas)

Appendix A: Description of IECM

Thorndike Landing uses its proprietary model, the Integrated Energy Capacity Model ("IECM"). The IECM is an economic forecasting tool that derives capacity and energy forecasts by combining a set of sophisticated market simulation algorithms into one integrated piece of software. Unlike most other standard forecasting software, capacity markets are integrated into the forecast rather than being modeled as an add-on, which aids greatly with the validity of return requirement calculations needed to add future resources to the model.

The model works in power markets that follow the rules of economic dispatch in the energy markets and that have a formal capacity market, a regulatory reserve margin requirement, or a bilaterally traded capacity market. This makes the IECM useful in most current domestic power markets.

Obvious Advantages of Integration

The real market linkage between energy and capacity markets is undisputed and is most relevant for the very important new build and retirement asset decisions (i.e., even markets with low spark spread forecasts and little incentive from an energy market perspective to install new plants or keep aging units operating will, in real life, encourage retirement delays or even new builds). The IECM allows the forecaster to easily integrate assumptions and results in both markets to arrive at conclusions to typically difficult questions, such as: "Does the capacity market in my region lead to new combustion turbines or does it put a new combined-cycle or coal plant into my new build assumption? Is there a difference under a carbon regime?"

Methodology

For the energy module, the IECM uses an hourly chronological merit order dispatch approach to arrive at a 20 year energy price forecast. These 175,000 price points are one part of the economic assessment for new and old resources. For the capacity module, the model applies the appropriate capacity market construct, e.g. a demand curve or a bilaterally traded market, to the same resources used in the energy module to derive an annual capacity market price point for the same 20 year period. Both the 175,000 energy and the 20 capacity price points enter the retirement and new build assumptions that then circle back into the two forecasts in an iterative fashion.

Emissions: Pollutants and Carbon Dioxide

The cost of emission allowances is an important adder to the marginal cost of fossil generators. In the case of CO_2, there is even uncertainty around such basic rules as allocation mechanisms and price caps. The IECM incorporates our standard forecasts for emission allowances and allows for scenarios around fuel and emission market dislocations.

Extrinsic Value Drivers

Models such as the IECM that use a fundamental approach to forecast energy prices typically exhibit a weakness when it comes to estimating the energy margin from plants that can be dispatched flexibly, based on market conditions. E.g., the average daily price on the same weekday in the same month may be very similar in the fundamental dispatch model, as it is likely based on similar load and fuel price conditions. In real markets, there are many parameters that shift the daily prices up or down. While the average will be roughly the same, this introduction of volatility into the pricing enhances the energy margins of the above mentioned flexible plants. In WECC, flexible plants, such as combustion turbines (CT) and combined-cycle (CC) plants are important as they form an important part of the new build economics. The model, if it did not include volatility in its output, would understate CC and CT returns, with the important impact that it would delay new build decisions, leading to exaggerated market heatrate forecasts. The IECM therefore, as a final step, after fundamental intrinsic prices are derived, introduces volatility into the generated pricing, not changing the absolute pricing levels, but introducing just enough volatility, on a simple mean-reverting basis, to result in appropriate returns for the flexible plants.

Key Assumptions and Results for the Various Scenarios

Note that gas prices refer to the AECO, and power prices to the Mid-C pricing points.

Core Underlying Commodity Assumptions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Natural Gas	$7.16/MM BTU	$6.96/MM BTU	$7.10/MM BTU	$7.24/MM BTU	$7.38/MM BTU	$7.53/MM BTU	$7.68/MM BTU	$7.84/MM BTU	$7.99/MM BTU	$8.15/MM BTU	$8.31/MM BTU
CO_2	$0/t	$0/t	$8/t	$8/t	$8/t	$10/t	$13/t	$16/t	$19/t	$22/t	$25/t
CO_2 (High Case Only)	$0/t	$0/t	$16/t	$16/t	$16/t	$20/t	$26/t	$32/t	$38/t	$44/t	$50/t
Hydro (of Normal)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Other (Low Case Only)		5,000 MW uneconomic CC capacity									
Resulting Market Heatrate											
Low	8,456	8,128	8,651	8,711	8,760	8,924	9,053	9,264	9,457	9,572	9,735
Base	8,456	8,526	9,056	9,090	9,116	9,247	9,368	9,549	9,720	9,824	9,969
High	8,456	8,526	9,546	9,574	9,594	9,835	10,114	10,452	10,774	11,017	11,299

Appendix B: Conditions and Assumptions

This report developed by Thorndike Landing shall be received and accepted with the accompanying limiting conditions and assumptions:

- This report has been prepared solely for the purposes stated and should not be used for any other purpose. The use and distribution of this report and the conclusions contained herein are limited as stated in the report and the related engagement letter.

- Our analysis: (i) assumes that as of the date of this report the Facility and its assets will continue to operate as configured as a going concern; (ii) is based on the past and present financial condition of the Facility and its assets; and (iii) assumes that the Facility had no undisclosed real or contingent assets or liabilities, no unusual obligations or substantial commitments, other than in the ordinary course of business, nor had any litigation pending or threatened that would have a material effect on our analyses.

- We have relied on information supplied by Avista without audit or verification. We have assumed that all information furnished is complete, accurate, and reflects Avista's good faith efforts to describe the status and prospects of the Facility at the date of this report from an operating and a financial point of view. As part of this engagement we have relied upon publicly-available data from recognized sources of financial information which have not been verified in all cases. Nothing came to our attention to make us believe that any of the information provided by Avista was other than reasonable.

- Any use of Avista's projections or forecasts in our analysis does not constitute an examination or compilation of prospective financial statements in accordance with standards established by the American Institute of Certified Public Accountants ("AICPA"). We do not express an opinion or any other form of assurance on the reasonableness of the underlying assumptions or whether any of the prospective financial statements, if used, are presented in conformity with AICPA presentation guidelines. Further, there will usually be differences between prospective and actual results because events and circumstances frequently do not occur as expected and these differences may be material.

- The terms of our engagement are such that we have no obligation to update this report or to revise our assessment because of events and transactions occurring subsequent to the date of this report.

- We assume no responsibility for legal matters including interpretations of either the law or contracts. We have made no investigation of legal title and have assumed that the owner(s) claim(s) to property are valid. We have given no consideration to liens or encumbrances except as specifically stated. We assumed that all required licenses, permits, etc. are in full force and effect, and we made no independent on-site tests to identify the presence of any potential environmental risks. We assume no responsibility for the acceptability of the valuation approaches used in our report as legal evidence in any particular court or jurisdiction. The suitability of our report for any legal forum is a matter for the client and the client's legal advisor to determine.

- Neither Thorndike Landing, nor any individual associated with this report shall be required to give testimony or appear in court or other legal proceedings unless specific arrangements have been made in advance.

- We have not investigated the extent of any hazardous substances that may exist, as we are not qualified to test for such substances or conditions. If the presence of such substances, such as asbestos, urea formaldehyde foam insulation, or other hazardous substances or environmental conditions may affect the valuation of the Facility, the valuation was estimated predicated on the assumption that there is no such condition on or in the property or in such proximity thereto that it would cause a loss in value. No responsibility is assumed for any conditions, or for any expertise or engineering knowledge required to discover them.

- We assume no liability whatsoever with respect to the condition of the Facility or for hidden or unapparent conditions, if any, of the subject property, subsoil or structures, and further assume no liability or responsibility whatsoever with respect to the correction of any defects which many now exist or which may develop in the future. Equipment components considered, if any, were assumed to be adequate for the needs of the Project's improvements, and in good working condition, unless otherwise reported.

Appendix C: Lancaster Toll Forecasted Financials, Valuation

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LANCASTER TOLL - BASE CASE

($000s unless otherwise noted)		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Selected Operational Measures:																			
Operational metrics																			
Months in service		12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	10	-
Capacity (MW)																			
Baseload		237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	-
Duct-fired		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	-
Total		262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	-
Financial Projections:																			
Energy margins, excluding allowances		17,068	17,207	17,660	18,169	18,670	19,200	19,003	19,731	20,516	20,344	20,864	21,432	21,020	21,672	22,349	22,012	18,935	-
Capacity revenues		17,109	17,421	17,740	18,063	18,393	18,730	19,072	19,421	19,776	20,138	20,506	20,881	21,264	21,653	22,050	22,454	19,055	-
Energy payment (toll)[1]		(3,337)	(3,390)	(3,402)	(3,505)	(3,608)	(3,697)	(3,736)	(3,832)	(3,921)	(3,962)	(4,056)	(4,177)	(4,232)	(4,356)	(4,484)	(4,541)	(3,897)	-
Gross margin		30,841	31,238	31,997	32,727	33,455	34,232	34,339	35,319	36,371	36,520	37,315	38,136	38,052	38,969	39,915	39,926	34,093	-
Non-fuel fixed operating expenses																			
O&M [2]		5,352	5,485	5,622	5,763	5,907	6,055	6,206	6,361	6,520	6,683	6,850	7,022	7,197	7,377	7,562	7,751	6,620	-
Transmission		1,170	1,200	1,230	1,260	1,292	1,324	1,357	1,391	1,426	1,462	1,498	1,536	1,574	1,614	1,654	1,695	1,448	-
Gas Transportation		3,410	3,461	3,513	3,566	3,619	3,674	3,729	3,785	3,842	3,899	3,958	4,017	4,077	4,138	4,200	4,263	3,606	
Capacity / capital toll payment [3]		15,100	15,251	15,404	15,558	15,714	15,871	16,029	16,190	16,352	16,515	16,680	16,847	17,016	17,186	17,358	17,531	14,755	-
Total non-fuel operating expenses		25,033	25,398	25,769	26,147	26,532	26,923	27,322	27,727	28,140	28,559	28,987	29,422	29,864	30,315	30,773	31,240	26,430	-
EBITDA		5,808	5,840	6,228	6,580	6,923	7,309	7,017	7,592	8,231	7,960	8,328	8,715	8,187	8,654	9,141	8,685	7,663	-
Tax Depreciation (based on purchase price)		113	217	200	185	171	159	147	136	134	134	134	134	134	134	134	134	134	
EBIT		5,696	5,624	6,027	6,394	6,752	7,150	6,871	7,457	8,097	7,826	8,194	8,581	8,054	8,521	9,007	8,551	7,529	-
Taxes		(2,275)	(2,246)	(2,407)	(2,554)	(2,697)	(2,856)	(2,744)	(2,978)	(3,234)	(3,126)	(3,273)	(3,427)	(3,217)	(3,403)	(3,598)	(3,415)	(3,007)	-
Depreciation (tax)		113	217	200	185	171	159	147	136	134	134	134	134	134	134	134	134	134	-
Capital Expenditures		(3,000)																	
Free Cash Flows		533	3,594	3,820	4,026	4,226	4,453	4,273	4,614	4,997	4,834	5,055	5,288	4,971	5,251	5,544	5,270	4,656	-
Terminal Value [4]																			187
NPV (mid-year convention)																			
Annual discount factor based on discount rate of:	7.41%	0.96	0.90	0.84	0.78	0.72	0.67	0.63	0.59	0.54	0.51	0.47	0.44	0.41	0.38	0.35	0.33	0.31	0.28
PV of annual cash flows @ discount rate of		515	3,229	3,195	3,135	3,064	3,005	2,685	2,699	2,722	2,451	2,387	2,324	2,034	2,001	1,966	1,740	1,431	52
Total NPV, excluding cost of imputed debt		40,635																	
Total NPV, excluding cost of imputed debt (rounded)		40,500																	
		155	($/kW)																

Footnotes:

[1] - Represents the energy payment portion of tolling payments. Amount is based on MWhs generated and an energy charge that is escalated annually with an inflation measure.

[2] - Represents the O&M portion of tolling payments. Amount is based on a flat charge (expressed in terms of $/kW-month) that is escalated annually with an inflation measure.

[3] - Represents the capital / capacity portion of tolling payments. Amount is based on a flat charge (expressed in terms of $/kW-month) that is escalated at 1% per year.

[4] - Terminal value represents tax benefit from write-off of undepreciated basis in capital outlay (interconnection costs)

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LANCASTER TOLL - LOW CASE `

($000s unless otherwise noted)		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Selected Operational Measures:																			
Operational metrics																			
Months in service		12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	10	-
Capacity																			
Baseload		237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	-
Duct-fired		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	-
Total		262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	-
Financial Projections:																			
Energy margins, excluding allowances		17,068	14,073	14,430	14,907	15,391	15,909	15,743	16,428	17,127	17,014	17,524	18,048	17,801	18,353	18,951	18,789	16,181	-
Capacity revenues		17,109	17,421	17,740	18,063	18,393	18,730	19,072	19,421	19,776	20,138	20,506	20,881	21,264	21,653	22,050	22,454	19,055	-
Energy payment (toll)[1]		(3,337)	(3,165)	(3,176)	(3,282)	(3,390)	(3,487)	(3,508)	(3,611)	(3,708)	(3,732)	(3,832)	(3,959)	(4,003)	(4,131)	(4,260)	(4,318)	(3,711)	-
Gross margin		30,841	28,330	28,993	29,689	30,394	31,152	31,307	32,238	33,195	33,419	34,198	34,970	35,062	35,876	36,741	36,925	31,525	-
Non-fuel fixed operating expenses																			
O&M [2]		5,352	5,485	5,622	5,763	5,907	6,055	6,206	6,361	6,520	6,683	6,850	7,022	7,197	7,377	7,562	7,751	6,620	-
Transmission		1,170	1,200	1,230	1,260	1,292	1,324	1,357	1,391	1,426	1,462	1,498	1,536	1,574	1,614	1,654	1,695	1,448	-
Gas Transportation		3,410	3,461	3,513	3,566	3,619	3,674	3,729	3,785	3,842	3,899	3,958	4,017	4,077	4,138	4,200	4,263	3,606	
Capacity / capital toll payment [3]		15,100	15,251	15,404	15,558	15,714	15,871	16,029	16,190	16,352	16,515	16,680	16,847	17,016	17,186	17,358	17,531	14,755	-
Total non-fuel operating expenses		25,033	25,398	25,769	26,147	26,532	26,923	27,322	27,727	28,140	28,559	28,987	29,422	29,864	30,315	30,773	31,240	26,430	-
EBITDA		5,808	2,933	3,224	3,542	3,862	4,229	3,985	4,510	5,055	4,860	5,211	5,548	5,198	5,561	5,967	5,685	5,095	-
Tax Depreciation (based on purchase price)		113	217	200	185	171	159	147	136	134	134	134	134	134	134	134	134	134	
EBIT		5,696	2,716	3,024	3,357	3,690	4,070	3,839	4,375	4,922	4,726	5,078	5,415	5,064	5,427	5,834	5,551	4,961	-
Taxes		(2,275)	(1,085)	(1,208)	(1,341)	(1,474)	(1,626)	(1,533)	(1,747)	(1,966)	(1,888)	(2,028)	(2,163)	(2,023)	(2,168)	(2,330)	(2,217)	(1,981)	-
Depreciation (tax)		113	217	200	185	171	159	147	136	134	134	134	134	134	134	134	134	134	-
Total capital expenditures		(3,000)																	
Free Cash Flows		533	1,848	2,016	2,201	2,388	2,603	2,452	2,763	3,090	2,972	3,183	3,386	3,175	3,393	3,638	3,468	3,113	-
Terminal Value [4]																			187
NPV (mid-year convention)																			
Annual discount factor based on discount rate of:	7.41%	0.96	0.90	0.84	0.78	0.72	0.67	0.63	0.59	0.54	0.51	0.47	0.44	0.41	0.38	0.35	0.33	0.31	0.28
PV of annual cash flows @ discount rate of		515	1,660	1,686	1,714	1,731	1,757	1,541	1,616	1,683	1,507	1,503	1,488	1,299	1,293	1,290	1,145	957	52
Total NPV, excluding cost of imputed debt		24,438																	
Total NPV, excluding cost of imputed debt (rounded)		$\boxed{24,500}$																	
		93	($/kW)																

Footnotes:

[1] - Represents the energy payment portion of tolling payments. Amount is based on MWhs generated and an energy charge that is escalated annually with an inflation measure.

[2] - Represents the O&M portion of tolling payments. Amount is based on a flat charge (expressed in terms of $/kW-month) that is escalated annually with an inflation measure.

[3] - Represents the capital / capacity portion of tolling payments. Amount is based on a flat charge (expressed in terms of $/kW-month) that is escalated at 1% per year.

[4] - Terminal value represents tax benefit from write-off of undepreciated basis in capital outlay (interconnection costs)

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LANCASTER TOLL - HIGH CASE `

($000s unless otherwise noted)		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Selected Operational Measures:																			
Operational metrics																			
Months in service		12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	10	-
Capacity																			
Baseload		237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	-
Duct-fired		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	-
Total		262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	-
Financial Projections:																			
Energy margins, excluding allowances		17,068	17,207	17,915	18,425	18,936	19,537	19,388	20,227	21,156	21,021	21,669	22,263	21,775	22,472	23,198	22,785	19,619	-
Capacity revenues		17,109	17,421	17,740	18,063	18,393	18,730	19,072	19,421	19,776	20,138	20,506	20,881	21,264	21,653	22,050	22,454	19,055	-
Energy payment (toll)[1]		(3,337)	(3,165)	(3,176)	(3,282)	(3,390)	(3,487)	(3,508)	(3,611)	(3,708)	(3,732)	(3,832)	(3,959)	(4,003)	(4,131)	(4,260)	(4,318)	(3,711)	-
Gross margin		30,841	31,464	32,478	33,207	33,939	34,780	34,952	36,036	37,224	37,427	38,343	39,185	39,036	39,995	40,988	40,921	34,962	-
Non-fuel fixed operating expenses																			
O&M [2]		5,352	5,485	5,622	5,763	5,907	6,055	6,206	6,361	6,520	6,683	6,850	7,022	7,197	7,377	7,562	7,751	6,620	-
Transmission		1,170	1,200	1,230	1,260	1,292	1,324	1,357	1,391	1,426	1,462	1,498	1,536	1,574	1,614	1,654	1,695	1,448	-
Gas Transportation		3,410	3,461	3,513	3,566	3,619	3,674	3,729	3,785	3,842	3,899	3,958	4,017	4,077	4,138	4,200	4,263	3,606	
Capacity / capital toll payment [3]		15,100	15,251	15,404	15,558	15,714	15,871	16,029	16,190	16,352	16,515	16,680	16,847	17,016	17,186	17,358	17,531	14,755	-
Total non-fuel operating expenses		25,033	25,398	25,769	26,147	26,532	26,923	27,322	27,727	28,140	28,559	28,987	29,422	29,864	30,315	30,773	31,240	26,430	-
EBITDA		5,808	6,066	6,709	7,060	7,407	7,856	7,630	8,309	9,084	8,867	9,357	9,764	9,172	9,680	10,215	9,681	8,532	-
Tax Depreciation (based on purchase price)		113	217	200	185	171	159	147	136	134	134	134	134	134	134	134	134	134	
EBIT		5,696	5,849	6,508	6,874	7,236	7,698	7,484	8,173	8,950	8,733	9,223	9,630	9,038	9,546	10,081	9,547	8,398	-
Taxes		(2,275)	(2,336)	(2,599)	(2,746)	(2,890)	(3,075)	(2,989)	(3,264)	(3,575)	(3,488)	(3,684)	(3,846)	(3,610)	(3,813)	(4,026)	(3,813)	(3,354)	-
Depreciation (tax)		113	217	200	185	171	159	147	136	134	134	134	134	134	134	134	134	134	-
Total capital expenditures		(3,000)																	
Free Cash Flows		533	3,730	4,109	4,314	4,517	4,782	4,641	5,045	5,509	5,379	5,673	5,917	5,562	5,867	6,188	5,868	5,178	-
Terminal Value [4]																			187
NPV (mid-year convention)																			
Annual discount factor based on discount rate of:	7.41%	0.96	0.90	0.84	0.78	0.72	0.67	0.63	0.59	0.54	0.51	0.47	0.44	0.41	0.38	0.35	0.33	0.31	0.28
PV of annual cash flows @ discount rate of		515	3,350	3,437	3,359	3,275	3,227	2,916	2,951	3,001	2,728	2,678	2,601	2,276	2,235	2,195	1,938	1,592	52
Total NPV, excluding cost of imputed debt		44,326																	
Total NPV, excluding cost of imputed debt (rounded)		$\boxed{44,500}$																	
		169	($/kW)																

Footnotes:

1 - Represents the energy payment portion of tolling payments. Amount is based on MWhs generated and an energy charge that is escalated annually with an inflation measure.

2 - Represents the O&M portion of tolling payments. Amount is based on a flat charge (expressed in terms of $/kW-month) that is escalated annually with an inflation measure.

3 - Represents the capital / capacity portion of tolling payments. Amount is based on a flat charge (expressed in terms of $/kW-month) that is escalated at 1% per year.

4 - Terminal value represents tax benefit from write-off of undepreciated basis in capital outlay (interconnection costs)

LANCASTER TOLL - COST OF IMPUTED DEBT

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Stream of capacity payments		21,126	15,251	15,404	15,558	15,714	15,871	16,029	16,190	16,352	16,515	16,680	16,847	17,016	17,186	17,358	17,531	14,755
Discount rate (AVA pre-tax cost of debt)	8.28%																	
NPV	148,692																	
Risk factor [1]	25%																	
Imputed debt	37,173																	
AVA capitalization structure:																		
Debt	58.6%																	
Preferred stock	1.4%																	
Common stock	40.0%																	
	100.0%																	
Equity required to maintain cap structure [2]	25,383																	
After-tax cost of equity	10.4%	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,200
NPV	24,926																	
NPV (rounded)	24,000																	

Footnotes:

[1] - Per S&P guidelines, a risk factor is applied to the discounted stream of Toll capacity payments based on regulatory / rate treatment (and likelihood of recoverability).

[2] - Represents the equity that would be required to be issued after the imputed debt in order to maintain current capitalization structure.

Executive Summary

Avista Utilities plans to acquire the Power Purchase Agreement for the 275 MW Lancaster Generating Facility ("Lancaster") combined cycle combustion turbine (CCCT), which is located in the company's service territory near Rathdrum, Idaho. Acquisition of the Lancaster Power Purchase Agreement is consistent with Avista's 2007 Integrated Resource Plan Preferred Resource Strategy, which calls for a natural gas fired CCCT to meet base load needs by 2011. The Lancaster CCCT Power Purchase Agreement acquisition was found to be cost-effective compared to similar CCCT base load resources.

Background and Summary

In February 2007, Avista Utilities was informed of the possibility to acquire the Power Purchase Agreement (tolling) rights for Lancaster sometime between 2009 and 2011. The Power Purchase Agreement acquisition opportunity presented itself during Avista Corporation's negotiation for the sale of Avista Energy.

In April 2007, the utility completed an initial assessment of the potential Lancaster Power Purchase Agreement acquisition. Avista Utilities Resource Planning staff performed an analysis based upon the 2007 Integrated Resource Plan (IRP) models. It had been determined, as part of the IRP process, that there was a need for energy and capacity within the relevant timeframe as evidenced by load and resource tabulations which showed an expected annual average energy deficiency starting in 2011. An analysis of the average Q1, Q3, and Q4 (no Q2) quarters indicated deficits beginning in 2010. Capacity deficits started at 146 MW in 2011 and grew into the future. Furthermore, guidance from the 2007 IRP indicated 350 MW of natural gas baseload resource as part of the Preferred Resource Strategy (PRS) over the first 10 years of the plan (2008-2017).

On April 17, 2007, Avista Corporation announced an agreement with Coral Energy to sell Avista Energy. As part of the agreement with Coral Energy, Avista Corporation would assume the Lancaster Power Purchase Agreement beginning January 1, 2010. The draft 2007 IRP Preferred Resource Strategy (PRS) that was presented to the Technical Advisory Committee members on June 6, 2007 included a discussion of the Lancaster Power Purchase Agreement opportunity and its fit with the PRS.

The sale of Avista Energy to Coral became effective on July 1, 2007 thereby transferring the Lancaster Power Purchase Agreement to Avista Utilities on January 1, 2010. In August 2007, Avista Utilities contracted for an independent assessment of the Lancaster Power Purchase Agreement relative to other utility gas-fired options. Thorndike Landing, LLC completed the study and assessment work in late October 2007. Thorndike Landing found the Lancaster Power Purchase Agreement acquisition favorable relative to other natural gas-fired CCCT generation options generally available to utilities in the Pacific Northwest.

This white paper provides an overview of the Lancaster Power Purchase Agreement as well as analysis and assessment documentation addressing the prudence criteria as articulated by the Washington Utilities and Transportation Commission (Eleventh Supplemental Order and the Nineteenth Supplemental Order both in Docket No. UE-920433) and by the Idaho Public

Utilities Commission (Order No. 28876 in Case No. AVU-E-01-11, dated October 12, 2001, and its Order No. 29130 in Case No. AVU-E-02-6, dated October 11, 2002).

Lancaster – Overview of the Agreements

The 275 MW Lancaster CCCT entered into service in 2001. As a combined-cycle combustion turbine, it is among the most efficient natural gas-fired plants in the Northwest. The plant is located in the utility's service area, near Rathdrum, Idaho. The Lancaster plant is configured with as a 245 MW natural gas-fired CCCT with an additional 30 MW of duct firing capability.

In addition to the Lancaster plant Power Purchase Agreement rights, the company will receive long-term natural gas transportation rights necessary to fuel the plant as well as long-term electric transmission rights for power off-take.

The following is a summary of each of the agreements:

1) The Lancaster Generating Plant and Power Purchase Agreement

The Lancaster plant Power Purchase Agreement is available to the company January 1, 2010 through October 31, 2026. In exchange for payments outlined in the Power Purchase Agreement agreement, the utility will have the right to dispatch the Lancaster plant. As such, the company is responsible to arrange and pay for natural gas fuel procurement and transportation to the Lancaster plant and is entitled to the entire plant electric capacity and energy output. The company will also be responsible for electric transmission to move power from the Lancaster plant.

2) Natural Gas Transportation Associated With Lancaster

The Lancaster plant is interconnected with the Gas Transmission Northwest (GTN) natural gas pipeline system. As part of the agreement with Coral, on January 1, 2010, the company will receive permanent assignment of firm natural gas transportation capacity on the TransCanada Alberta and TransCanada BC systems and temporary assignment of firm natural gas transportation capacity on the GTN system. The GTN temporary assignment of firm transportation capacity on the GTN pipeline by Shell Corporation terminates on October 31, 2017. These firm transportation arrangements will allow for deliveries of approximately 26,000 Dth/d from the AECO trading hub on the Alberta system and approximately 26,000 Dth/d from either the Stanfield or Malin trading hubs south of the plant off of the GTN system.

3) Electric Transmission Associated With Lancaster

The Lancaster plant is interconnected electrically with the Bonneville Power Administration (BPA). There is a transmission agreement, held by the company in the name of Avista Energy, with BPA for 250 MW of long-term transmission capacity rights from the Lancaster point of receipt to the John Day point of delivery that was assigned to Coral on a short term basis through December 31, 2009. Effective January 1, 2010, there will be a permanent assignment of the long-term transmission rights to Avista Corporation.

The Lancaster CCCT Power Purchase Agreement Is Needed for Utility Service

The company was engaged in the process of finalizing its Integrated Resource Plan in April 2007 when the Lancaster Power Purchase Agreement option was evaluated for potential acquisition by Avista Utilities. At that time the tabulation of the company's loads and resources (L&R) positions showed energy and capacity deficits beginning in 2011; the energy deficit was 73 MW; the capacity deficit was 146 MW. Those needs increased substantially in the years 2012 and beyond. The February 2007 L&R tabulation is shown in Table No. 1 below.

Table No. 1
February 23, 2007 L&R Tabulation

Position	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Energy (aMW)	131	88	42	(73)	(156)	(162)	(194)	(219)	(272)	(263)
Capacity (MW)	148	94	5	(146)	(251)	(268)	(324)	(357)	(414)	(300)

The company submitted its 2007 IRP on August 31, 2007. There was only a small increase in amount of the energy deficit for 2011. The 2007 IRP L&R tabulation is shown in Table No. 2.

Table No. 2
2007 IRP L&R Tabulation

Position	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Energy (aMW)	121	79	33	(83)	(170)	(178)	(206)	(228)	(281)	(272)
Capacity (MW)	148	94	5	(146)	(251)	(268)	(324)	(357)	(414)	(300)

The utility's current October 25, 2007 L&R tabulation (without the Lancaster Power Purchase Agreement included) continues to show energy and capacity deficits beginning in 2011 (20 aMW, 83 MW). The updated L&R tabulation was based on the company's latest load forecast and assessment of resource capabilities and maintenance. The October 25, 2007 L&R tabulation is shown in Table No. 3.

Table No. 3
October 25, 2007 L&R Tabulation

Position	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Energy (aMW)	125	94	(20)	(86)	(123)	(127)	(179)	(211)	(225)	(245)
Capacity (MW)	116	43	(83)	(166)	(203)	(252)	(325)	(370)	(252)	(283)

The company's 2007 IRP process indicated that 350 MW of additional base-load CCCT capability (nameplate MW) should be included in the overall PRS for the first 10 years (2008 – 2017) of the 20-year planning horizon. The IRP process considers not only the cost of certain resource options, but also their contribution to meeting other planning goals such as reducing portfolio risk and meeting renewable portfolio standards. The 2007 IRP evaluated numerous options available to the utility, including gas-fired CCCTs, wind plants, biomass plants, and various coal-fired technologies. Given these options, the IRP identified a preferred mix of future resource alternatives.

The company used the PRiSM decision support software to help guide its resource planning decisions. The PRiSM model brings together the intrinsic and extrinsic values of Avista's existing portfolio of resources, its load obligations, and resource opportunities available to meet future load requirements. To capture the optionality inherent in each resource option (listed in the 2007 IRP, Table 8.1) available to the company, the results from 300 Monte Carlo runs were considered. Capital, transmission and fixed operations and maintenance costs attributable to each new resource option were evaluated. PRiSM was used to review the existing resource portfolio and select an optimal mix of new resources from the available options. Alternative resource mixes, including the PRS mix, were subjected to additional comparison and testing to assess the optimum balance of risk and cost. The PRS was selected on a comparative basis taking into account the balance of risk and costs of different resource mix strategies.

The resulting PRS for the first 10-year period of the 2007 IRP shows a need to add 772 MW of new resources consisting of the following resource types: 350 MW – Combined Cycle Combustion Turbine; 300 MW - Wind Generation; 35 MW – Other Renewable; 87 MW – Conservation. The Lancaster CCCT fills a portion of the PRS mix.

The Lancaster Plant Is Cost-Effective

<u>April 2007 Analysis:</u>

The April 2007 analysis of the Lancaster Power Purchase Agreement, along with associated natural gas transportation and electric transmission agreements, showed the acquisition of the Lancaster Power Purchase Agreement to be cost-effective compared to other alternatives. Because a firm transfer date for the Lancaster Power Purchase Agreement had not been set as part of the overall negotiations concerning the sale of Avista Energy to Coral Energy, the analysis initially looked at three potential start dates of January 1st of 2009, 2010 or 2011. The January 1, 2010 date ultimately became the agreed upon transfer date.

The company analyzed Power Purchase Agreement start date alternatives from two planning scenarios. The first scenario was based on the load and resource tabulation that was developed as part of the ongoing 2007 IRP process which indicated annual average deficits beginning in 2011. This load and resource tabulation was based on the company's traditional planning margin criteria, which is approximately 15% of peak load. The second scenario was an adjusted load and resource tabulation based on the Northwest Planning and Conservation Council (NPCC) planning reserve margin level of 25% of peak load. This load and resource tabulation indicated an immediate 2008 planning deficit.

For the January 1, 2010 Power Purchase Agreement transfer date, the analysis demonstrated the Lancaster Power Purchase Agreement was less costly than either a new "greenfield" or a potential existing "brownfield" natural gas-fired CCCT plant alternative. The Lancaster Power Purchase Agreement was estimated to save customers $4 million under the traditional planning reserve scenario and $22 million based on the NPCC planning reserve scenario, on a present value basis when compared to a brownfield site. A similar comparison to a greenfield site indicated present value saving of $62 million under the traditional reserves planning scenario and savings of $78 million based on the NPCC planning reserve scenario.

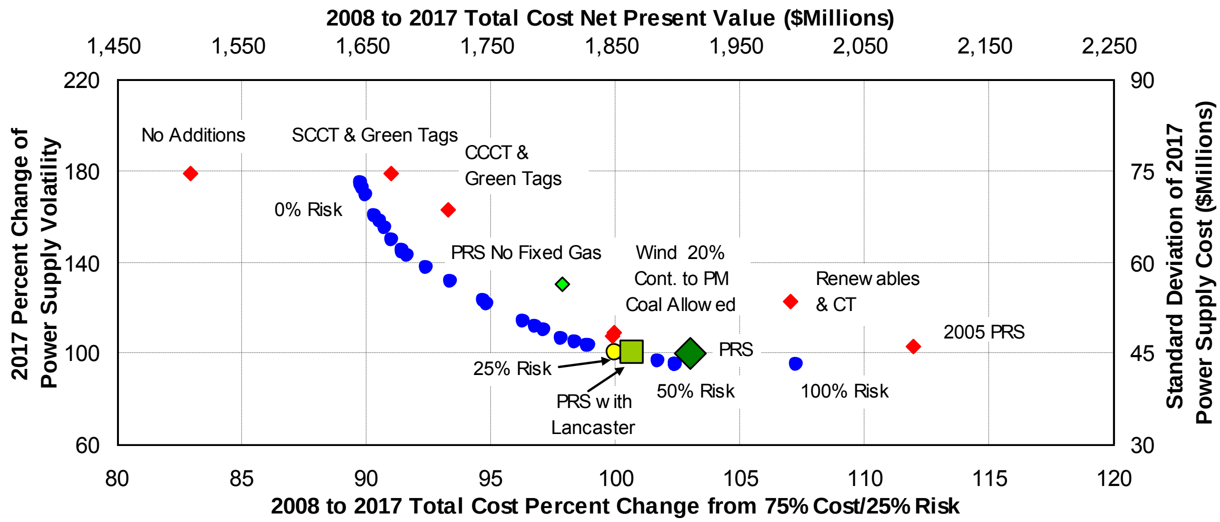
Lancaster's location in the company's Idaho service territory has the advantage of avoiding the nearly 4% Washington state fuels tax. However, that comparative savings was not considered in the April 2007 analysis. The comparative benefit from the lack of fuel tax in Idaho is estimated to add an additional $2 million in annual savings, or approximately $15 million on a present value basis. Another factor in favor of the Lancaster Power Purchase Agreement that was not explicitly included in the economic comparison to other new plant alternatives was the absence of construction risk.

<u>2007 Integrated Resource Plan – Lancaster Assessment:</u>
The 2007 IRP had already developed assessments of resource alternatives and had determined the PRS for the company at the time that the Lancaster Power Purchase Agreement opportunity was made to the utility. As stated earlier, the IRP considers not only the cost of certain resource options, but also their contribution to meeting various other planning goals such as reducing portfolio risk and meeting renewable portfolio standards. After assessing the costs and benefits of various resource mix options, a PRS was selected in the 2007 IRP process which included the addition of 350 MW of new gas-fired CCCT generation as part of that resource mix within the first ten years of the plan.

Subsequent to the announcement concerning the sale of Avista Energy to Coral energy on April 17, 2007, the company made the IRP Technical Advisory Committee aware of the Lancaster Power Purchase Agreement and the timing of its transfer to Avista Corporation on January 1, 2007. Lancaster was identified as a technologic match with the 350 MW of CCCT that was part of the PRS. Given that and because the Lancaster was available to the utility in the same timeframe as the PRS, there was not a need to update the strategy in the 2007 IRP. The 2007 IRP explained that the Lancaster Power Purchase Agreement reduced costs by 2.3% relative to the original PRS that included 350 MW of new gas-fired CCCT generation as shown in Table No. 4 below. The document states, on page 8-30, that "savings are created by acquiring a more cost-effective plant [relative to a greenfield plant] and an adjustment to new resource additions [changing the timing of other new resource additions]."

As explained earlier, the preferred resource strategy is selected based on a balance between resource mix cost and risk. A graphical depiction from the final 2007 IRP shows how Lancaster provides a similar risk profile while being lower-cost than the PRS absent the Lancaster Power Purchase Agreement.

Table No. 4
2007 Integrated Resource Plan
Figure 8.32: Efficient Frontier with Lancaster Plant



Thorndike Landing, LLC – Independent Valuation:

In August 2007 the company retained an independent consulting firm to perform an assessment of the Lancaster Power Purchase Agreement acquisition. Thorndike performed a ___ year discounted cash flow (DCF) analysis to determine the intrinsic and extrinsic value of the Power Purchase Agreement under Base, High and Low case scenarios. The base case assumes that Lancaster can be interconnected to the Avista transmission system and that the transmission will be remarketed or otherwise optimized to recover 75% of the cost. The high case scenario included a doubling of CO_2 prices. The low case scenario included the addition of 5,000 MW of combined cycle capacity throughout the WECC, which negatively impacts margins. The total value of the Lancaster Power Purchase Agreement, as dispatched against the market, was positive in all three cases.

Table No. 5
Lancaster Power Purchase Agreement Value vs. Market

Description	Power Purchase Agreement Value ($000)	Power Purchase Agreement Value ($/kW)
Base Case	$16,500	$64
Low Case	$500	$2
High Case	$20,500	$78

Because the transmission cost assumption had a material impact on the Lancaster valuation, Thorndike Landing performed sensitivity analyses based on the percentage of the BPA 250 MW transmission cost that would be recovered through remarketing it to third parties. The analyses show the Lancaster Power Purchase Agreement has positive value in all cases except where none of the transmission is remarketed.

Table No. 7
Transmission Impact On Lancaster Power Purchase Agreement Value

Percent of BPA Transmission Cost Re-marketed	Power Purchase Agreement Value ($000)	Power Purchase Agreement Value ($/kW)
100%	$24,750	$94
75%	$16,500	$64
67%	$13,750	$52
50%	$8,500	$33
33%	$3,000	$12
25%	$500	$2
0%	($7,500)	($29)

Based on the above valuation perspectives, Thorndike stated that they "found that the Toll provides positive value to Avista and its customers….and the value of the Lancaster facility appears consistent with – if not greater than – the value of other resources in the market."

Thorndike further performed a review of Avista's analytic process and methodology to identify any potential shortcomings or areas that might be improved to provide the company with a better, more comprehensive analytical process. Thorndike identified two items [exclusion of natural gas transportation costs and exclusion of costs associated with imputed debt] to warrant further consideration by Avista. They concluded that those items did not have a material impact on the calculated values or the overall conclusions with respect to the Lancaster Power Purchase Agreement. Thorndike found that "Avista's analytical process and methodology is a very contemporary approach to analyzing resources." Thorndike furthers stated that "[w]e have found that Avista's analytic process is sound and even surpasses processes used by many of their peers across the industry."

Avista's initial April 2007 assessment, the 2007 IRP analysis, and the Thorndike Landing independent review all indicate that the Lancaster Power Purchase Agreement is cost-effective compared to other resource options under base case conditions as well as under various different scenarios.

The Lancaster Facility is Highly Dispatchable

The Power Purchase Agreement for the Lancaster plant provides its owner the ability to operate the plant in a flexible manner as if the utility owned the plant itself.

Gas-fired CCCT plants are one of the most dispatchable electricity-generating technologies available to utilities. Relative to other viable options, only simple-cycle gas-fired turbines can have more operational flexibility. Gas-fired CCCTs are capable of providing energy and capacity on short notice. The plants also can provide capacity for both spinning and non-spinning reserves. Many utilities use a portion of CCCT plant capacity to provide regulation services. Gas-fired CCCTs with the “duct-firing” capability of Lancaster provide additional flexibility to meet changing load and market conditions. CCCTs, by their inherent design, operate significantly more efficiently over a range of operating levels when compared to simple-cycle CTs.

The IRP modeling process dispatches all resource options to the wholesale marketplace. Where a resources' cost is lower than purchasing power from the market, the model causes that plant to run and the savings, as compared to market, are tracked for the portfolio. The modeling accounts for start-up costs, plant heat rates, and minimum up and minimum down times when it considers whether or not to dispatch a resource. The model also accounts for minimum and maximum generating levels, as well as hourly ramp rate capabilities. In the case of CCCT plants like Lancaster, the IRP dispatch model also separately dispatches duct-firing capabilities using each plants’ unique heat rate, operating characteristics, and costs, bringing that capacity on-line when market conditions support it.

Electric Transmission

The Lancaster plant is currently interconnected only to the BPA transmission system. As stated above, the utility will receive assignment of 250 MW of firm transmission capacity on the BPA transmission system as part of the acquisition of the Lancaster Power Purchase Agreement beginning January 1, 2010. The transmission point of receipt is Lancaster and the point of delivery is John Day at the head of the Southern Intertie.

Compared to other CCCT projects in the region, Lancaster is unique as it is located within the company’s service area. The utility plans to investigate whether the Lancaster project can be directly interconnected to the Avista transmission system in the Rathdrum area. The BPA interconnection agreement for Lancaster is held by the project owners [Cogentrix/Goldman Sachs and Energy Investors Funds Group].

The cost of the BPA transmission was explicitly included in the Lancaster modeling and analyses by both Avista and by Thorndike Landing. The base case assumes that Lancaster can be interconnected to the Avista transmission system and that the transmission will be remarketed or otherwise optimized to recover 75% of the cost.

Avista and Thorndike did consider an alternative, due to economics or other factors, where the Lancaster plant is not directly interconnected to the company’s transmission system. In that case, a smaller portion of the transmission would be remarketed principally at times when the plant is not operating. However, because the firm transmission currently has John Day as a point of delivery, there may be opportunity to capture additional value for customers by selling power at that point or at COB. Firm power sales into California can often command a higher price compared to purchasing replacement power for delivery within the Northwest region. Optimization through selling power at COB or John Day and buying power in the region may be an alternate method of covering some of the cost of the BPA transmission if an interconnection with the Avista transmission system is not reasonably achievable.

Natural Gas Transportation

The Lancaster plant benefits from firm gas transportation from AECO to the Malin trading hubs. This transportation can serve the entire needs of Lancaster, including duct firing (approximately 46,168 Dth/d). This firm transportation will allow for deliveries of up to 26,256 Dth/d from the AECO trading hub on the Alberta system and up to 26,388 Dth/d from either the Stanfield or Malin trading hubs south of the plant. This dual source approach gives the company the ability to fuel the plant at an overall lower cost than if the firm transportation was solely from the AECO trading hub to the plant intake. Further, this transportation arrangement allows the company to make use of any excess transportation for other gas-fired generation resources such as the Coyote Springs 2 project duct firing, the Rathdrum combustion turbine project and/or the Boulder Park generation project. During periods where Lancaster is not dispatched and the transportation is not utilized for other Avista gas-fired facilities, the utility may be able to optimize the transportation value by purchasing gas at the lowest priced trading point on the transportation path and selling gas at the highest-priced trading point on the transportation path. During extended periods where the plant is offline, the company also has the option of releasing the transportation capacity in the capacity rePower Purchase Agreement market.

The transportation capacity on the GTN pipeline segment, in both the north-to-south and the south-to north directions, is under a contract held by Shell Corporation that will be temporarily assigned to Avista Corp for the period January 1, 2010 through October 31, 2017. Shell currently holds roll-over rights to that capacity. The company expects to be able to acquire transportation capacity necessary to replace that temporary assignment of firm capacity on the GTN system prior to October 31, 2017.

Comparison To Other Combined Cycle Combustion Turbine Plants

The Lancaster Power Purchase Agreement opportunity was made available to the utility as part of the sale of Avista Energy to Coral Energy. The company made comparisons to other similar resources based on industry data available at the time. In addition, the company had requested Thorndike Landing to perform comparisons to other combined cycle plants as part of their independent analysis.

<u>Avista IRP – Comparative Analysis:</u>
As stated earlier, the company's 2007 IRP selected 350 MW of combined cycle combustion turbine resource for acquisition by 2017. The IRP used generic resource assumptions to provide a roadmap with regard to the type of resources that Avista should procure. The company

developed the generic CCCT plant cost from a combination of NPPC data, purchased plant modeling data, and other publically available plant cost data. The generic CCCT plant is assumed to be located in Idaho, resulting in lower fuel costs, and connected to Avista's transmission system thereby avoiding third-party wheeling charges. The expected cost for the generic CCCT resource was $786 per kW in 2007 dollars ($850 per kW in 2010 dollars) and escalated at 2.8% per year. Using the plant and market data from the 2007 IRP, a generic resource beginning service in 2010, was estimated to cost $83.64 per MWh (2010 nominal dollars, levelized over the period 2010-2040 and excluding the cost to firm natural gas transportation)[1].

Avista – Plant Comparisons:

Shortly after Avista Energy's sale to Coral, Goldman Sachs announced that it was selling its interest in Lancaster along with a substantial portion of its Cogentrix's resource portfolio. The Lancaster Generation Facility, along with 13 other facilities across the country, was put up for auction. Avista responded to Goldman's announcement with a proposal for the purchase of Lancaster. Goldman later sold 80% of its Cogentrix resource portfolio interest, including Lancaster, to Energy Investors Funds Group for an undisclosed amount.

Avista performed several Lancaster valuation studies in preparation for making a purchase proposal, which included a comparison to similar combined cycle combustion turbine plant transactions in the Northwest. The analysis included comparisons between Coyote Springs 2, Port Westward, Goldendale, and Lancaster. The comparative analysis calculated the levelized cost of each plant as if Avista owned the resource. Table No. 8 shows the levelized costs in nominal 2010 dollars for each resource studied. This table shows that the Lancaster Power Purchase Agreement is slightly more expensive than Avista's previous acquision of Coyote Springs 2. The Port Westward and Goldendale plants would be significantly more costly to Avista because of fuel costs and other costs associated with the locations of the facilities. Port Westward and Goldendale both have fuel supplies based on higher Sumas prices whereas Lancaster and Coyote Springs 2 are based on AECO prices. Goldendale is also at a financial disadvantage because it must pay the Washington state fuel tax and has a higher heat rate because of its hybrid cooling technology. The Port Westward project is a greenfield facility which has relatively higher capital requirements.

Table No. 8
Lancaster Levelized Cost vs. Other Regional CCCT Projects

Plant	Levelized Cost (2010-2026) $/MWh
Coyote Springs 2	78.37
Goldendale	97.72
Port Westward	92.80
Lancaster Power Purchase	79.37

[1] The 2007 IRP at page 6-19 shows a CCCT cost estimate of $65.14 per MWh in 2007 levelized real dollars over the plant life. This amount is equivalent to the $83.64 per MWh in 2010 levelized nominal dollars.

Agreement	

For each plant, the levelized cost consists of all fuel costs, variable O&M, transmission cost and losses, emissions costs (based on 2007 IRP), fixed O&M, fuel transport, outage risk, site value, property taxes, income taxes, state fees, and Power Purchase Agreement payments and debt equivalent charges. The levelized cost values shown are based on the plants operating at their maximum availability. In reality, the plants would not operate during all periods of the year, and would be displaced with lower cost market purchases.

The levelized cost results shows that the Lancaster project Power Purchase Agreement is comparable to the Coyote Springs 2 project and a better alternative than either the Goldendale or Port Westward projects would have been for Avista's customers.

Thorndike Landing – Plant Comparison:

Thorndike also performed a valuation of Lancaster under an ownership scenario which was then compared to ownership values of other recent plant transactions. This represents the present value of the difference between the variable dispatch costs, fixed O&M, insurance, and taxes for each plant compared to the project market net revenue. [Note that the variable dispatch cost does not include the Power Purchase Agreement cost in the case of Lancaster or the recovery of capital or fixed costs in the case of other plants.] The comparison indicates that the Lancaster project has a greater value than other recently constructed or transacted facilities in the region. Though Avista does not own the Lancaster plant, this comparison is a strong indication that a similar Power Purchase Agreement (or toll) opportunity at one of these other plants would be somewhat less favorable economically to the company than the Lancaster opportunity. Plant values are summarized in the following Table No. 9

Table No. 9
Lancaster Plant Value vs. Other Regional CCCT Projects

Description	Plant Value ($000)	Plant Value ($/kW)
Lancaster	$177,500	$677
Coyote Springs 2	$169,500	$652
Port Westward	$236,000	$528
Goldendale	$84,000	$365

Thorndike Landing attributes the greater relative value of the Lancaster project to the following primary drivers:

- Lower electric transmission costs;
- Lower natural gas transportation costs;

- Lower natural gas taxes (the state of Idaho has no fuel tax); and
- Dual sourcing of fuel (Alberta/Malin vs. Sumas).

Self-Build Alternatives

As described in the cost-effectiveness section, self-build options were expected to be more expensive than the Power Purchase Agreement agreement. The Power Purchase Agreement was estimated to be between $62 and $78 million dollars less than an equivalent greenfield project. Thorndike Landing concurred with this conclusion.

Revenue Requirement Impact

While the Lancaster project becomes available one year prior to the company's annual average resource need in 2011, as indicated in the company's 2007 IRP, it is a timely opportunity to acquire a base-load resource at a cost lower than a new greenfield project and at a lower cost for Avista than similar projects transacted in the region. Even when compared to an alternative greenfield combined cycle combustion turbine plant that would come on-line with perfect timing, the Lancaster plant has a lower revenue requirement impact.

Table No. 10 shows the expected annual revenue requirement impact over the period 2010 through 2026 for Lancaster and a greenfield and brownfield plant, along with the decreased revenue requirement for the Lancaster plant compared to other capacity alternatives. The revenue requirement impact is calculated by subtracting the spot market energy value of the plant from the total plant cost. The remaining revenue requirement impact represents the capacity cost of acquiring a new resource.

As shown in Table No. 10 below, a greenfield plant coming on-line in 2011 would be expected to cause a levelized revenue requirement impact that is $11.3 million/year greater than Lancaster over the period 2010 to 2026. Acquisition of a similar brownfield plant located outside of the utility's service territory (at a cost of $500/kW as shown in the April 2007 analysis) is calculated to have a levelized revenue requirement impact that is $300,000/year greater than Lancaster over the period 2010 to 2026.

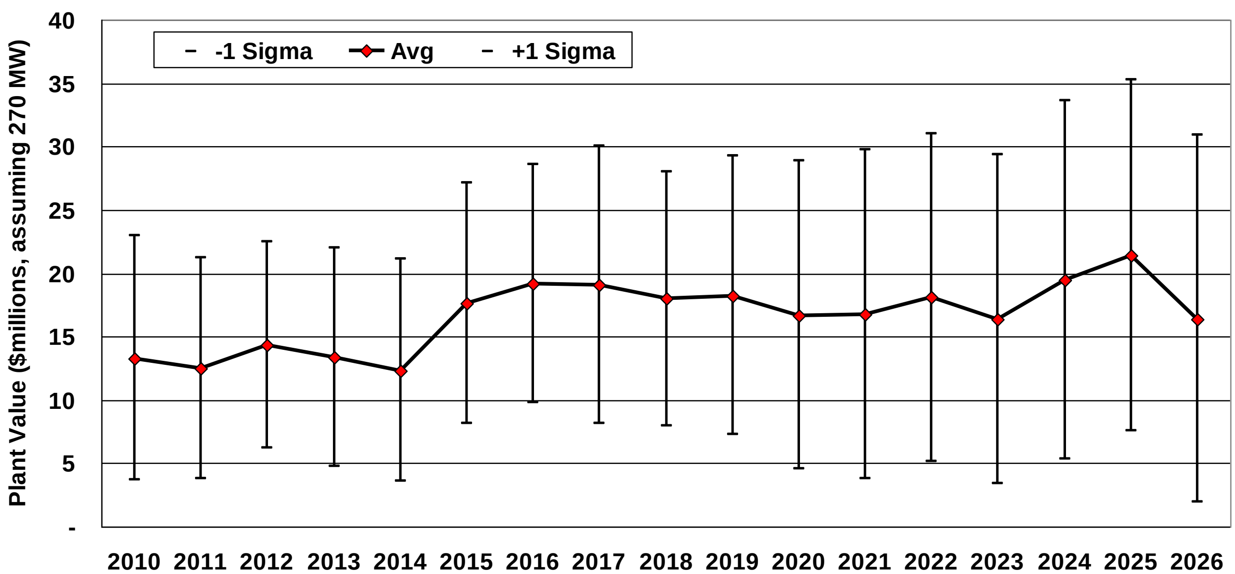
Table No. 10
Annual Revenue Requirement Impact ($million/year)

	Revenue Requirement Impact			Lancaster Savings vs	
Year	$850/kW Green Field	$500/kW Brown Field	Lancaster Lease	$850/kW Green Field	$500/kW Brown Field
2010	0.0	0.0	12.9	(12.9)	(12.9)
2011	31.3	18.3	14.2	17.1	4.2
2012	32.8	18.7	13.0	19.8	5.7
2013	32.9	19.2	14.3	18.5	4.9
2014	33.1	19.9	15.8	17.3	4.1
2015	27.4	14.7	11.3	16.1	3.3
2016	25.4	13.1	10.5	14.9	2.6
2017	24.9	13.0	11.1	13.8	1.9
2018	25.3	13.8	12.6	12.7	1.2
2019	24.6	13.4	12.9	11.6	0.5
2020	25.5	14.7	14.9	10.5	(0.2)
2021	24.9	14.6	15.5	9.4	(0.9)
2022	23.2	13.3	14.9	8.4	(1.6)
2023	24.3	14.8	17.1	7.3	(2.3)
2024	21.0	11.8	14.8	6.2	(3.0)
2025	18.8	10.0	13.7	5.1	(3.7)
2026	23.0	14.6	19.0	4.0	(4.4)
Levelized	25.5	14.5	14.1	11.3	0.3

Sensitivity Analyses

Several sensitivity analyses were performed as part of the Lancaster assessment process. The company's IRP analysis process provided figures for both the intrinsic and extrinsic values of the Lancaster plant over 300 Monte Carlo iterations of market conditions (varied for natural gas price, hydroelectric generation levels and forced outages) during the term of the Lancaster Power Purchase Agreement. 2007 IRP results for the range of value attributed to a gas-fired CCCT are show in Table No. 11 below.

Table No. 11
Lancaster Plant Value – Sensitivity Analysis



Thorndike Landing valued the Lancaster tolling arrangement under Base Case, Low Case and High Case conditions as explained in their report and the results of which are previously summarized in Table No. 5. That sensitivity analysis indicates that the Lancaster plant performs well against the market due largely to circumstance that natural gas-fired generation is the marginal resource in the regional marketplace.

Review of Long Term Power Purchases in the Pacific Northwest During 2007

Presented to

Avista Utilities

March 17, 2010

Presented by

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1. Executive Summary

Avista Utilities ("Avista") is an operating division of Avista Corporation. Avista generates, transmits and distributes electricity and distributes natural gas in and around Spokane, Washington and other areas of north eastern Washington and northern Idaho.

The Lancaster Power Plant ("Lancaster") is a 275 MW combined cycle power plant located in Rathdrum, Idaho that achieved commercial operation in 2001. Lancaster is owned by Rathdrum Power LLC which is an independent power producer and unrelated to Avista Corporation. Output from Lancaster is purchased by Avista Turbine Power Inc. ("Avista Turbine"), a subsidiary of Avista Corporation, under a power purchase agreement with Rathdrum Power LLC that expires in 2026 (the "Lancaster PPA").[1] The Lancaster PPA allows for purchase of 100% of the capacity and energy from Lancaster with certain dispatch rights for the purchaser. In 2007, Avista Corporation elected to take future assignment of all the rights and obligations under the Lancaster PPA beginning in 2010 for the purpose of serving the capacity and energy needs of Avista for the balance of the Lancaster PPA term (approximately 17 years). To affect the assignment, Avista Corporation entered into a new power purchase agreement with Avista Turbine dated December 7, 2009 (the "New Lancaster PPA") to which the Lancaster PPA is attached. Under the New Lancaster PPA, Avista Corporation purchases from Avista Turbine all electrical capacity and energy available from Lancaster pursuant to the terms of the Lancaster PPA.

Avista has retained Navigant Consulting, Inc. to review the conditions of the market for long term PPAs for capacity and energy in the Pacific Northwest market segment ("PNW") during 2007 and determine whether or not at the time 1) there were similar power resources with similar price structures (e.g. long term fixed price, tolling arrangement or asset purchase) that were available to Avista at a cost lower than the Lancaster PPA, and 2) if Avista would have been able to meet the credit terms required for such purchases.

Publicly available information was obtained and analyzed to identify the attributes and prices of other similar power purchase opportunities in the PNW that might have been available to Avista in 2007. We reviewed the filings of several major wholesale market participants in the PNW (other than Avista) including PacifiCorp, Puget Sound Energy ("Puget") and Portland General Electric ("PGE").

Our findings and conclusions are as follows:

1. **No similar long term unit-contingent PPAs were available.** Only one existing long term unit contingent PPA was expiring and could have been available to Avista at the time. This was from the Sumas Cogeneration plant in northwestern Washington.

[1] Appendix A to the Power Purchase Agreement dated December 7, 2009 between Avista Turbine Power, Inc. as Seller and Avista Corporation as Purchaser.

However, the potential new purchase would have had a higher heat rate and lower dispatchability than the Lancaster PPA. Therefore, the potential PPA would not have been similar to the Lancaster PPA. Also, the plant was encumbered by a dispute under its prior PPA with Puget Energy and was eventually purchased by Puget Energy as part of the settlement. Therefore the potential PPA would not have been available to Avista. Finally, transmission across both the Puget and BPA transmission systems would have been required at additional cost (a double wheel).

2. **No similar long term system-backed PPAs were available.** Only one existing long term system backed PPA was expiring and could have been available to Avista at the time. However, the purchase would likely not have met the carbon emission standard of RCW 80.80.040 due to a coal fired component. Also, the gas fired component of the purchase would have come from a relatively small and fuel inefficient plant resulting in a relatively high heat rate as compared to Lancaster. Therefore, the potential PPA purchase would not have been similar to the Lancaster PPA.

3. **No similar PPAs from newly built plants were available at lower cost.** Only one long term PPA from a newly constructed plant (650 MW Grays Harbor Satsop) could have been available to Avista at the time. It is currently under a 20 year PPA with a power marketer. However, FERC filings indicate that capacity prices being paid under that PPA are higher than those under the Lancaster PPA.

4. **No other major PNW market participants were successful in procuring similar PPAs.** PacifiCorp, PGE and Puget were all actively procuring power in the 2004-2007 time period for delivery in 2010 and beyond. However, none of them entered into a long term (10+ year) PPA. They either proposed or built their own similar resource, acquired existing plants, or entered shorter term PPAs. It is likely that Avista would have experienced this same outcome if it had held similar procurement activities at the time.

5. **Not being investment grade at the time, Avista may have had to post millions in collateral to enter into a similar PPA.** Industry standard PPAs require a non-investment grade buyer to post collateral if and when PPA prices are higher than the then forecast market prices ("over-market"). If a seller would have transacted with Avista at the time, Avista may have had to post approximately $69 million in collateral based on a collateral calculation that was in use by a major market participant at the time.

This Report summarizes our review and conclusions as of the date of this Report. In preparing this Report, we have relied on documents, correspondence, analyses and information from various private and public sources. While we believe these documents and information to be reliable, they have not been independently verified for either accuracy or validity, and no assurances are offered with respect thereto. We make no representations, warranties or opinions concerning the enforceability or legality of the laws, regulations, rules, agreements or

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other similar documents reviewed as part of this evaluation. NCI and its employees are independent contractors providing professional services to Avista and are not officers, employees, or agents of Avista.

2. Review of the Lancaster PPA Price and Non-Price Attributes

The Lancaster PPA was first reviewed to understand its key price and non-price attributes in preparation for identifying alternative PPAs that might have been available to Avista in 2007.

The Lancaster PPA is structured as a "tolling arrangement", under which the Purchaser is responsible for purchasing and delivering natural gas fuel to Lancaster, the seller is responsible for converting that fuel to electricity, and the Purchaser is responsible for taking away (scheduling) that electricity. For this tolling service, the Purchaser pays the seller both a monthly Capital Charge and a monthly O&M Charge based on the quantity of power generation capacity made available to the Purchaser that month ($/kw-mo), plus an Energy Payment based on the quantity of energy generated that month ($/MWh). There are additional periodic charges for any plant startups or additional capacity utilized. It is important to note that the Energy Payment does not include the cost of fuel consumed to produce energy, since the Purchaser pays his fuel supplier/transporter directly for this. The seller must operate and maintain Lancaster such that fuel will be converted to power at or below a specific rate (the Guaranteed Heat Rate in Btu/kwh). The Capital Charge is reduced in months where availability is below a certain rate (Availability Adjustment Factor). The seller must also ensure that Lancaster can be operated within specific load limits and can be started and brought up in load within certain time constraints (design limits).[2]

The Capital Charge escalates at 1% annually. Both the O&M Charge and the Energy Payment escalate annually at a rate equal to the prior year change in gross domestic product implicit price deflator ("GDP-IPD") as published by the federal government. For the 2009 contract year, the combined Capital Charge and O&M Charge was approximately $6.967/kw-month, the Energy Payment was approximately $2.536/MWh, and the Guaranteed Heat Rate was approximately 7,050 Btu/kwh at 100% dispatch.[3]

In addition to the above price attributes, the Lancaster PPA provides important non-price benefits and risks to the Purchaser.

The Lancaster PPA provides the Purchaser with the ability to manage the cost and volatility of natural gas fuel, the largest component of overall power cost under the PPA. Under the tolling structure, the Purchaser has the ability to provide gas fuel from its own reserves or supply

[2] Power Purchase Agreement dated as of December 7, 2009 between AVISTA TURBINE POWER, INC., as Seller and AVISTA CORPORATION, as Purchaser

[3] Lancaster PPA, Appendix H Schedule of Payments, using reported GPD-IPD values from 1997 through 2009, assuming full plant availability, and heat rate as reported by Avista.

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sources, or construct a portfolio of gas purchases (short term, long term, small volume, large volume, different supply basins, etc), and/or to enter into hedging arrangements to effectively limit or fix the cost of natural gas fuel to Lancaster. The Purchaser typically has much greater resources and capabilities than the seller to take these actions. In addition, the Purchaser is not exposed to any special fuel management or markup fees that the seller might impose if it were to provide fuel.

The tolling structure also provides the Purchaser with the ability to schedule and dispatch Lancaster as necessary within the Design Limits to meet load and other commitments. There is no "minimum-take" of energy that could result in uneconomic dispatch of other Purchaser resources. Lancaster also serves as a source of non-spinning reserve, spinning reserve, voltage control, regulation and other ancillary service that are of value to the Purchaser.

The Lancaster PPA also represents a long term power resource. Generally, PPAs longer than 10 years are considered a long-term resource within the industry. The current remaining term of the Lancaster PPA term is 17 years and can be extended an additional 5 years by mutual agreement. The major charges under the PPA escalate at very low fixed rates, or rates that are tied to general increases in inflation, and therefore do not represent a significant price volatility risk to the Purchaser.

The ability to control fuel cost and dispatch are "ownership-like" rights that have value to the Purchaser and must be considered in evaluation of alternative PPA arrangements.

3. Methodology Used to Identify Alternative Similar PPAs

The Lancaster PPA is a long-term, dispatchable, unit contingent tolling arrangement. Publicly available information was obtained and analyzed to identify the attributes and prices of other similar power purchase opportunities in the PNW that might have been available to Avista in 2007. These purchases generally could have been available from the following types of sources:

Type 1) Existing Long-Term Unit Contingent Roll Off ("LU Roll-off") - an existing large combined cycle generating plant making primarily long term market sales (an Independent Power Producer or "IPP") with an existing PPA scheduled to expire on or before January 1, 2010.

Type 2) Existing Long-Term System Firm Roll Off ("LF Roll-off") - a utility or IPP with a portfolio of existing plants with excess capacity that was willing to create and sell a large (270+MW) "synthetic" long term dispatchable tolling arrangement.

Type 3) New Build PPA - a planned new large gas fired IPP plant with a planned commercial operation date on or before January 1, 2010.

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To identify the LU Roll-off and LF Roll-off opportunities that may have been available to Avista in 2007, we researched and reviewed publicly available information on existing wholesale power contracts in the PNW during the years 2001 through 2009. Reviewing years prior to and after 2007 was necessary to identify contracts that either 1) expired around the 2007 timeframe, perhaps making the underlying resources available for contracting by Avista, or 2) began around the 2007 timeframe indicating a new PPA opportunity that Avista might have missed. To identify New Build PPA opportunities, we reviewed the status of gas fired combined cycle plants under development in the PNW in the 2007 time frame and the power sale proposals they had made in the market.

The most comprehensive publicly available source of data on wholesale power purchases is the data that market participants must file annually with the federal government. These filings include the FERC Form 1 and the Energy Information Administration ("EIA") Form 412. They also include the Electric Quarterly Reports that all utilities and power marketers must file summarizing the contractual terms and conditions for market-based power sales, cost-based power sales, and transmission service.

IOUs are required to report unit-designated PPAs separately from system backed PPAs. Unit designated PPAs of five years of longer are designated as Long-term Service from a Designated Generating Unit ("LU"). Non-unit contingent, system backed PPAs of five years or longer are designated as Long-term Firm Service ("LF"). Therefore, for this Report we focused on purchases labeled as "LU" as a proxy for an LU Roll-off Opportunity and "LF" as a proxy for an LF Roll-off Opportunity.

We reviewed the filings of several major wholesale market participants in the PNW (other than Avista) including PacifiCorp, Puget Sound Energy ("Puget") and Portland General Electric ("PGE").[4] The Bonneville Power Administration ("BPA") is also a major market participant. However, BPA participates primarily as a seller of power from the Federal Columbia River Hydroelectric System and therefore was not reviewed. Idaho Power is also a market participant. However, Idaho Power serves southern Idaho which is physically and electrically remote from Avista and therefore was not reviewed. The filings of NorthWestern Energy, Seattle City Light and Snohomish PUD were also reviewed. However, there was either no reported LU or LF activity, or the terms of the PPAs were only 5 years, so these participants were not reviewed further.

The availability of long term firm transmission service is also a key factor in determining similar purchase opportunities. There must be adequate long-term firm transmission capacity across the BPA system to deliver a similar purchase to Avista. If sufficient long term firm capacity is not available, then the purchase cannot serve as a firm capacity resource without incurring significant transmission upgrade costs and associated siting and construction lead

[4] Data collected from SNL Interactive, Industry Analysis, Electric Supply, Purchased Power Contracts. SNL data collected from the FERC Form 1.

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time. The same holds true if the purchase if first delivered to a third party (non-BPA) transmission system (a "double wheel"). The cost of this additional wheel across the third party system would increase the cost of the purchase to Avista relative to the Lancaster PPA.

4. No Similar Unit Contingent PPAs Were Available in 2007

We reviewed the long term, unit contingent wholesale power purchases that PacifiCorp, Puget and PGE had in place in 2007 or 2008 to identify LU Roll-Off opportunities.

For PacifiCorp, there were no purchases beginning or ending in the 2007 timeframe.

For Puget, no purchases were beginning and only one purchase was ending in 2007. The purchase that was ending was from Sumas Cogeneration Co LP, a 125 MW combined cycle cogeneration plant that entered commercial operation in 1993. The purchase was a 15 year qualifying facility ("QF") power purchase contract that was in dispute. Sumas Cogeneration was eventually purchased by Puget in December 2008 as part of the dispute settlement. [5]

Review of data reported to FERC by Sumas Cogeneration for the years 2001 through 2008 reveals an annual average heat rate of 7,837 Btu/kwh.[6] This is significantly higher than the heat rate under the Lancaster PPA. In addition, fuel purchased for the plant would have been subject to the Washington state natural gas use tax of 3.852% because the project is located in the State of Washington.[7] The 125 MW purchase would have provided only half the capacity and energy of the 275 MW Lancaster PPA. Finally, Avista would have incurred the additional cost of wheeling the purchase across the Puget system (a double wheel).

For PGE, our review revealed they had no long term, unit contingent wholesale power purchases that were beginning or ending in 2007 or 2008.

In summary, it appears that only one LU Roll-off opportunity (Sumas Cogeneration) may have been available to Avista in 2007. However, the plant was encumbered by a dispute under its prior PPA with Puget, and was eventually purchased by Puget as part of the dispute settlement. Also, evidence indicates that the potential new purchase would have had a higher heat rate than the Lancaster PPA. Finally, transmission across the Puget transmission system would have been required at additional cost (a double wheel). We conclude that no long-term unit-contingent PPAs similar to the Lancaster PPA were available to Avista in 2007.

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[5] Conversation with Puget Sound Energy, March 8, 2010.

[6] SNL Interactive, Companies and Assets, Sumas Cogeneration LLP, Summary Operating Data 2008.

[7] Washington State Department of Revenue, Natural Gas Use Tax, http://dor.wa.gov/content/FindTaxesAndRates/OtherTaxes/tax_naturalgas.aspx

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5. No Similar System-Backed PPAs Were Available in 2007

To identify the LF Roll-off opportunities that may have been available to Avista in 2007, we again reviewed the purchased power filings of PacifiCorp, Puget and PGE for the years 2001 through 2009.

Review of the PacifiCorp purchases indicated that one LF purchase was terminated in 2007. The terminated PacifiCorp purchase was with TransAlta Energy Marketing ("TransAlta"). It is likely that the purchase was backed by generation from the Centralia coal fired plant (1,376 MW) and their Centralia gas fired plant (248 MW, formerly Big Hannaford) located west of the Cascades between Seattle and Portland. These are TransAlta's only generating resources in the PNW and were both available for "merchant" sales in 2006.[8] The majority of energy likely came from Centralia due to the high capacity factor for the coal plant relative to the gas plant as reported by TransAlta.[9] Since this was reported as a firm contract, TransAlta must have also have been delivering additional capacity and energy from other purchases it was making at Mid-Columbia.

Although potentially available to Avista, the purchase would likely not have met the carbon emission standard of RCW 80.80.040 due to the coal fired component.[10] Also, the gas fired plant consists of four LM6000 combustion turbines which are smaller and less fuel efficient than those at Lancaster. This is evidenced by a reported average annual heat rate of over 9,000 BTU/kwh for the plant.[11] Therefore, the potential PPA would not have been similar to the Lancaster PPA.

Review of the Puget purchases reveals two LF purchases that started or stopped in the 2007-08 timeframe. However, one was related to hydroelectric purchase from Grant County PUD, the other from the Klondike Wind project. Neither is similar to the Lancaster PPA.

Review of the PGE LF purchases reveals that two BPA purchases ended in 2006. These contracts likely represented the Residential Exchange program of BPA where energy was delivered to IOUs to benefit the residential customers of the IOUs that otherwise would not receive benefits of the federal hydropower system. Beginning in the fiscal year 2007, BPA began providing a monetary benefit to PGE rather than physical power.

In summary, it appears that only one LF Roll-Off purchase from TransAlta may have been available to Avista in 2007. However, the purchase would likely not have met the carbon emission standard of RCW 80.80.040 due to the coal fired component. Also, the gas fired

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[8] TransAlta Corporation, 2006 Renewal Annual Information Form, For The Year Ended December 31, 2005

[9] SNL Interactive, Companies and Assets, TransAlta Centralia Coal Financial Summary, TransAlta Centralia Gas Financial Summary

[10] The Revised Code of Washington (RCW) RCW 80.80.040 Greenhouse gas emissions performance standards — Rules — Sequestration.

[11] SNL Interactive, Companies and Assets, TransAlta Centralia Generation, Summary Operating Data 2008.

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component of the purchase would have come from a relatively small and fuel inefficient plant resulting in a relatively high heat rate as compared to Lancaster. The potential purchase is therefore not similar to the Lancaster PPA. We conclude that no long-term system backed PPAs similar to the Lancaster PPA were available to Avista in 2007.

6. No Similar New Build PPAs Were Available in 2007 at Lower Cost

As described previously, a New Build PPA opportunity would be a purchase from a planned new large gas fired IPP plant with a planned commercial operation date on or before January 1, 2010.

To identify New Build PPA opportunities, we first researched and reviewed publicly available information on new combined cycle power generating plants that were known to be under development in the PNW in 2007.[12] A power plant developer typically will execute power purchase sale agreements with off-takers as soon as possible during the development process in order to gain additional equity funding, accelerate the permitting and interconnection processes with regulatory authorities, and obtain project financing on a timely basis.

There were six large scale (>250 MW) combined cycle projects under development. Two were planned for Washington, three for Oregon and one for Montana. There were no projects planned for Idaho, in particular for northern Idaho which is part of the Avista service territory and would have been a convenient point of receipt on the Avista transmission system.

The BP Cherry Point project was a 720 MW combined cycle cogeneration plant proposed by BP West Coast Products, LLC ("BP") for Whatcom County, Washington. BP received a site certificate for the project from the Washington Energy Facility Siting Council ("WEFSC") in late 2004. The location would have required transmission wheeling across the Puget and BPA systems to reach an Avista point of delivery (a double wheel). As a cogeneration project, it would likely have had a higher heat rate due to the required export of steam to the steam host. In addition, fuel purchased for the plant would have been subject to the Washington state natural gas use tax of 3.852% because the project is located in the State of Washington. Also, it is likely that little or no dispatch flexibility would have been offered. Cogeneration plants typically operate as base-loaded facilities due to the requirement to continuously export steam to the steam host. By late 2006, construction on the project had not yet started and the site certificate was amended to delay the planned commercial operation date until the summer of 2009. In July 2007, BP notified the Washington Energy Facility Siting Council that it was indefinitely postponing the project.

The Grays Harbor Satsop project is a 650 MW CCCT plant located near Olympia, Washington. It was under construction at the time and achieved commercial operation in July 2008. It is

[12] Power Plant Development Activity in the Pacific Northwest 2002 – Present, Northwest Power Planning Council http://www.nwcouncil.org/energy/powersupply/NewProjects.xls

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owned by Invenergy, an independent power producer based in Chicago. The plant is interconnected with the BPA system. The location would have required transmission wheeling across the BPA system to reach an Avista point of delivery. In addition, fuel purchased for the plant would have been subject to the Washington state natural gas use tax of 3.852% because the project is located in the State of Washington.

Given that Grays Harbor Satsop is in operation, we researched information concerning power sales and prices for the plant. FERC filings[13] indicate that Grays Harbor Energy LLC holds 3 long term power contracts. The first is a 20 year PPA with Sempra Energy Trading that was executed in January 2007. The second is a 20 year PPA with Powerex that was executed in April 2007. The third is a 20 year PPA with Eagle Energy Partners that was executed in June 2008. However, only the Eagle Energy Partners PPA has volumes and prices reported for it during 2008 and 2009. Eagle Energy Partners was acquired by EDF Trading in October 2008. EDF Trading is a 100% owned subsidiary of EDF, Europe's largest power utility.

Prices for the EDF Trading PPA were not reported for each month. For months in which prices were reported, it appears that the total capacity charge to EDF Trading was approximately $8/kw-month which is higher than the total capacity charge (Capital Charge plus O&M charge) under the Lancaster PPA (approximately $6.969/kw-month in 2009). It also appears that the non-fuel variable charge was at least $2.50/MWh which is nearly the same as the similar Energy Payment under the Lancaster PPA (approximately $2.536/MWh in 2009).

With respect to Oregon, the Wanapa project was a 1,300 MW CCCT plant proposed by Diamond Wanapa I, LLP ("Diamond") near Umatilla. Diamond received approval of its air quality permit in August 2005 which required construction to commence within 18 months (mid 2007).[14] Wanapa would have been interconnected to the BPA McNary substation requiring transmission service across the BPA system to reach an Avista point of delivery. The capacity of the project was very large relative to Avista's need (275 MW). A PPA with Wanapa would likely have been contingent on Diamond securing several additional PPAs with other parties in order to achieve project financial close, begin construction and ultimately deliver power to Avista. This contingency would have increased the risk of a Wanapa PPA relative to the Lancaster PPA. We found no evidence that the plant ever entered construction. We suspect that development of the project was suspended in the 2008 timeframe.

Also in Oregon, the COB Generating Facility and the Klamath Generating Facility were proposed for locations near Malin. Avista would have required firm transmission across both the COB-John Day and North of Hanford flow paths on the BPA system, potentially a "double-wheel" on BPA and higher cost relative to Lancaster. As with Wanapa, the capacity of the COB

[13] Energy Quarterly Reports for Grays Harbor Energy LLC, FERC website, Documents and Filings, EQR, Accessing Data. http://www.ferc.gov/docs-filing/eqr

[14] U.S. EPA Prevention of Significant Deterioration Permit to Construct issued to Diamond Wanapa LLP, August 2005.

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Generating Facility project was very large relative to Avista's need (275 MW). A PPA with the COB Generating Facility would likely have been contingent on the developer securing several additional PPAs with other parties in order to achieve project financial close, begin construction and ultimately deliver power to Avista. This contingency would have increased the risk of a COB Generating Facility PPA relative to the Lancaster PPA. Development of the COB Generating Facility was suspended in early 2007. Development of the Klamath Generating Facility has been delayed, with a planned construction start date now in November 2011.

With respect to Montana, the Great Falls Energy Center was a 275 MW CCCT plant planned for interconnection to the NorthWestern Energy transmission system south of Great Falls.[15] At the time of the Lancaster decision, the project was undergoing a revision to its air quality permit to account for an alternative combustion turbine model and for a phased (simple cycle, then combined cycle) construction approach. It was also well into the transmission interconnection request process with NorthWestern Energy. Its queue position is still active today, with a planned commercial operation date of 8/1/2010 for simple cycle and 8/1/2012 for combined cycle operation.[16] However, interconnection cost estimates have skyrocketed[17] and construction has not yet started. To accept the power, Avista would have needed to secure transmission service across the NorthWestern Energy system. NorthWestern has reported that they currently have only 177 MW of Available Transmission Capacity ("ATC") from Great Falls to Avista, falling to 0 MW starting in July 2010.[18] In addition, the wheeling rate across the Northwestern System is $37.92/kw-year ($3.16/kw-month)[19] , more than double the typical BPA wheeling cost of approximately $1.5/kw-month including ancillary service costs.[20] Therefore, even if the capacity price of the Great Falls Energy Center was comparable to that of the Lancaster PPA (approximately $6.969/kw-month in 2009), the cost of wheeling across the Northwestern Energy transmission system would significantly increase the monthly capacity cost of the purchase relative to the Lancaster PPA.

In summary, it appears that only the Grays Harbor Satsop project may have been a New Build PPA opportunity for Avista in 2007. The other large scale CCCT projects were either subject to cogeneration costs and constraints, were so large as to represent a contracting risk to Avista, or were located such that Avista would not have been able to secure long term firm transmission service to deliver their output to the Avista system. Grays Harbor Satsop did secure a 20 year

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[15] Great Falls Tribune, *Far from folding up their tent, Montgomery Energy officials said Tuesday they plan to expand a proposed natural gas-fired power plant north of Great Falls*. http://www.cce-mt.org/Links/past%20articles/files/Montgomery_Not_Folding_Tent.htm

[16] NorthWestern Energy Interconnection Queue, February 2, 2010. http://www.oatioasis.com/nwmt/nwmtdocs/Interconnection_queue.xls

[17] SNL Financial, *FERC denies complaint over NorthWestern's handling of its interconnection queue*, May 21, 2008

[18] NorthWestern Energy transmission staff, March 16, 2010.

[19] NorthWestern Corporation Open Access Transmission Tariff, Seventh Revised Volume No. 5 (MT), Schedule 7 Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service.

[20] BPA Transmission Services, Long-Term Firm Available Transfer Capability (ATC) Updated: 01/07/10

PPA with EDF Trading, an energy marketing subsidiary of the EDF group of France. However, review of FERC filings indicates that prices under the EDF PPA are higher than those under the Lancaster PPA. We conclude that no New Build PPAs similar to the Lancaster PPA were available to Avista in 2007 at prices lower than those under the Lancaster PPA.

7. Other Purchasers Were Not Successful in Procuring Similar PPAs

In addition to review of potential existing contract roll-off and new build PPA opportunities, the procurement efforts of PacifiCorp, Puget and PGE during 2007 were also reviewed as an indicator of market conditions for long term capacity and energy purchase from dispatchable resources at the time. The success (or failure) that these other IOUs experienced in long term resource procurement should be a key indicator of what Avista would have experienced if it had held similar procurement activities at the time.

7.1. PacifiCorp

In 2006, PacifiCorp issued an RFP for up to 1,700 MW of baseload supply-side resources capable of delivering unit contingent or firm capacity and associated energy into PacifiCorp's eastern control area by June 1, 2012, June 1, 2013 and/or June 1, 2014 (the "2012 RFP"). Eligible resources included PPAs, development of a new plant on an existing PacifiCorp site (either Currant Creek or Lakeside), asset purchase of an existing facility either in whole or in part, or restructuring of an existing PPA. PacifiCorp filed drafts of the 2012 RFP in July 2006, in October 2006, and again in February 2007. Proposals in response to the RFP were submitted on June 29, 2007. A conditional final short-list was identified in December 2007. The list was narrowed in mid-February 2008 to a single proposal, the Lake Side II proposal ("Lakeside") which had been submitted by PacifiCorp itself.

In February 2009, PacifiCorp terminated the construction contract for Lakeside. PacifiCorp cited declines in load growth, continued declines in forward electricity and gas prices, the outlook for future plant construction costs, and additional transmission import capability into Utah that had been confirmed through recently completed transmission studies. PacifiCorp subsequently terminated the 2012 RFP.

PacifiCorp was not successful in procurement of long term PPAs similar to the Lancaster PPA.

7.2. Portland General Electric

In June 2003, PGE issued an RFP for power supply resources. Bidding closed on July 23. PGE reported it had received 3 offers for peak period tolling, 2 offers for peak period tolling from CCCT duct firing, and a 2 seasonal exchange offers.

Based on the results of the RFP and other changes, PGE filed an IRP Final Action Plan in March 2004. The Final Action Plan called for, among other things, construction of a new 350 MW

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combined cycle project (Port Westward), procurement of 135 MW of fixed price PPAs (or up to 50 MW of baseload energy tolling PPAs), and 400 MW of tolling PPAs for peak purposes.[21]

In March of 2006, PGE reported that it had acquired 132 MWa in PPAs as targeted in the Final Action Plan. This included a new 10-year, 100 MW fixed-price PPA with TransAlta under which PGE receives energy according to actual production at the underlying power plant with an annual expected energy purchase of 93 MWa (a 93% capacity factor). This purchase is likely backed with energy from the Centralia coal plant, and therefore not available to Avista under the requirements of RCW 80.80.040. They also reported executing a five-year fixed price PPA for 25 MWa, along with a 25 MW base-load tolling agreement which was expected to provide 14 MWa of energy. PGE also reported executing two contracts totaling 400 MW of peak system tolling to meet winter peak load demands. Both capacity contracts were natural gas peak tolling arrangements, whereby PGE has the right to receive power based on a pre-determined plant heat rate and a regional market price for gas. One of the contracts is for up to 300 MW available during the winter months from 2006 through April 2011. The other contract for 100 MW is available for peak winter months beginning in December 2005 and ending in 2010.[22]

PGE was not successful in procurement of long term PPAs similar to the Lancaster PPA.

7.3. Puget Sound Energy

In November 2005, Puget issued a Request for Proposals from All Generation Sources for up to 1,500 MW of energy and capacity by 2015 (the "2005 RFP"). The 2005 RFP requested PPAs of varying contract lengths, exchange agreements (e.g., locational and seasonal), and capacity products (including operating reserves) to meet Puget's winter peak requirements. Capacity products had to be dispatchable/on peak or during winter only (Nov-Feb) heavy load hours (6x16 Mon-Sat HE0600-HE2200), able to provide operating reserves (regulating or contingency), spinning reserve, load following capability, and ten-minute start capability. Puget was willing to consider existing and yet-to-be constructed generation resources with commercial operation dates up to 2015. Puget was also willing to consider taking full or partial ownership of the resource, joint development by the respondent and Puget, development by the respondent and then transfer to Puget, initial purchase of power by Puget with transfer of ownership later, or other approaches that may have been mutually beneficial and result in PSE's ownership of the resource.

In August 2006, Puget announced it was pursuing the acquisition of up to approximately 1,100 megawatts (MW) of long-term power supply from seven outside sources that were proposed under the 2005 RFP. These included three existing natural-gas-fired power plants in Washington, and two purchased-power agreements not tied to specific generating plants. Puget subsequently announced that it had acquired the 2 year old 277 MW Goldendale CCCT

[21] PGE Final Action Plan, 2002 Integrated Resource Plan, March 2004.
[22] Portland General Electric 2002 Integrated Resource Plan Final Action Plan Update, March 2006

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plant in south-central Washington from the Calpine Corporation (February 2007) and the 125 MW Sumas Cogeneration project (December 2007).

In January 2008, Puget issued another RFP seeking up to 1,340 MW of new power-supply resources by 2015 (the "2008 RFP"). Puget subsequently announced that it had acquired the plant 9-month-old, 310-MW Mint Farm CCCT plant in Longview, Washington for $240 million. The plant acquisition was among PSE's four short-listed targets resulting from the 2008 RFP.

Puget was not successful in procurement of long term PPAs similar to the Lancaster PPA.

7.4. Summary of Procurement Activities of Other Market Participants

In summary, PacifiCorp, PGE and Puget were all actively procuring power in the 2004-2007 time period for delivery in 2010 and beyond. PacifiCorp had issued an RFP for PPAs or asset purchase of thermal generating resources. However, PacifiCorp ultimately delayed and then terminated the RFP due to declines in load growth, continued declines in forward electricity and gas prices and the outlook for future plant construction costs. PGE had also issued an RFP for thermal backed purchases, but ultimately built its own CCCT resource and entered into PPAs of 10 years or less duration. Puget had issued 2 separate RFPs for PPAs or asset purchase of thermal resources. Ultimately, Puget acquired three existing CCCT plants that were proposed in response to the RFP. In none of the cases did the purchaser enter into a long term (10+ year) UC or UF PPA. We conclude that none of these major market participants were successful in procurement of long term (10+ year) PPAs similar to the Lancaster PPA in 2007. Given that Avista operates in the same wholesale power market, we believe that Avista would have experienced the same result if it had held similar procurement activities at the time.

8. Avista May Have Faced Significant Collateral Requirements

In addition to determining what similar PPA opportunities may have been available to Avista in 2007, we reviewed the credit requirements that sellers were requiring of buyers in the market for long term transactions at that time. This is important because Avista's credit rating in 2007 was BB+ which is considered below "investment grade". Sellers may have shunned Avista as a purchaser because of this credit rating, or have required Avista to post significant collateral against failure to pay. This collateral amount must be considered when comparing the cost of an alternative PPA to the Lancaster PPA. The Lancaster PPA does not require the posting of collateral.

8.1. Observed Credit and Collateral Requirements

We were unable to obtain a copy of any executed long term LU or LF PPA that was in place during 2007 in order to examine the credit and collateral requirements. PPAs are typically considered confidential information and subject to protective order with the relevant regulatory agencies with which they are filed. We were only able to observe the credit requirements that were included in various standard form agreements that were being proposed or used within the PNW and adjacent areas at the time. These agreements and credit requirements are summarized below.

The Western Systems Power Pool (WSPP) Agreement (the "WSPP Agreement") is FERC approved and has been used by jurisdictional and non-jurisdictional entities throughout the west since 1991.[23] The WSPP Agreement does not have a minimum creditworthiness requirement. Posting of collateral can be required by either party upon ratings downgrade or other reasons, in an amount based on a Termination Payment calculation. Indications are that no participants are doing long term power sales under Schedule C (firm capacity/energy sale) due to concerns over credit quality.[24]

The Edison Electric Institute (EEI) Master Power Purchase & Sale Agreement ("EEI Master") is also FERC approved and has been used since 2000 by more than 80 EEI member utilities, affiliated and independent power marketers, merchant power, and end-use representatives. It also has no minimum creditworthiness requirement. However, a party can request posting of collateral in the form of either cash, letter(s) of credit, or other security acceptable to the requesting party ("Performance Assurance") in case of i) "reasonable concern", or ii) if the potential economic loss to the party that would result from termination of the PPA exceeds a pre-agreed Collateral Threshold, or if iii) the other party's credit rating falls pre-agreed levels (a "Downgrade Event").

As part of its 2012 RFP, PacifiCorp published a draft form Tolling Service Agreement. This was a custom PPA developed specifically for a New Build PPA opportunity. It contained extensive credit requirements for the bidder (seller) but none for PacifiCorp as Buyer. This was also the case with similar draft form PPAs published by Puget for their 2008 All-Source RFP.

PGE published a draft form PPA as part of its 2008 Renewable RFP. The PPA allowed either party to request assurances (posting of collateral) in the amount that a termination payment (with respect to a maximum 24-month period) that would be payable to that Party exceeds its specified collateral threshold. Similarly, Idaho Power published a draft form PPA for its 2008 Baseload RFP that required the seller to post performance assurances in the event buyer believes the seller's creditworthiness had become risky.

Finally, Pacific Gas & Electric (PG&E) published a draft form PPA as part of its 2008 All Source RFP. The RFP sought new, long-term dispatchable, operationally flexible resources with on-line dates no later than May 2015. The PPA has detailed Collateral Threshold specifications for

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[23] http://www.wspp.org/filestorage/current_effective_agreement_012110

[24] Conversation with Iberdrola Renewables, February 2010 and Avista, March 2010.

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both the seller and the Buyer.[25] Similar to the EEI Master, the Collateral Threshold is agreed at the inception of the PPA. It changes over the life of the PPA if and when there is a change in credit rating (worse rating means lower threshold) or a default (goes to zero). There is also a calculation of monthly intrinsic value ("MIV") which is effectively a "mark-to-market" approach to valuing the variable cost components of the PPA (fuel and non-fuel variable O&M). It is similar to the Termination Payment concept in the EEI Master except that the PG&E calculation covers only 5 years of future exposure. In months where the then current PPA price is above the market price for power, the resulting MIV is positive. A positive MIV represents a risk to the seller that the Buyer may stop purchasing power under the PPA in favor of cheaper power from the market. If the sum of all forecast MIVs over the next 5 years is greater than the Collateral Threshold, then the Buyer must post collateral equal to the excess of MIV over the threshold. The collateral amount cannot exceed $250 per kilowatt of contracted capacity.

It is interesting to note that the PG&E did not differentiate between tolling agreements and fixed price PPAs in its collateral calculation methodology. Fixed price PPAs are those where the energy price is not tied to a market index and/or offers no dispatchability. Tolling agreements should have lower collateral requirements than fixed price PPAs since the buyer has the ability to not take energy (dispatch to zero) if and when market prices are less than the cost of energy from the plant thereby mitigating an "over-market" situation. However, the collateral requirement would not be zero since the buyer must still pay the capacity price and would likely face mark-to-market collateral requirements under the natural gas purchase contract used to fuel the plant. The collateral requirements under the natural gas contract should be of similar size to those under a fixed price PPA since fuel is the largest component of PPA cost. This may have been PG&E's reasoning for not differentiating between the two different PPA types.

8.2. Estimated Collateral Requirement for Avista

We estimated the collateral that Avista would have had to post if it had entered a long term PPA in 2007 similar to the Lancaster PPA. We used a "mark-to-market" methodology similar to what is used to calculate a Termination Payment under the EEI Master or the MIV under the PG&E draft form PPA. We assumed that the purchase would be from a new 275 MW CCCT plant in Washington with the same non-fuel variable and fixed charges as under the Lancaster PPA and over the same term (10/31/2026). We also assumed a heat rate of 7,000 Btu/kwh which is typical for a new, large scale combined cycle power plant. For natural gas fuel prices, we used actual monthly prices reported for gas sold at the AECO Hub in Alberta, plus the cost of delivery down the GTN pipeline to Stanfield, plus the Washington State natural gas use tax of 3.852%. For market power prices, we used actual daily prices reported for power sold at the

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[25] Pacific Gas & Electric, 2008 All Source Request for Offers, Appendix F: Power Purchase Agreement - Composite as of 07-03-08 redline, paragraph 8.2 Determination of Collateral Requirements and Appendix VI - Determination Of Mark To Market Value. http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/allsourcerfo

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Mid-Columbia ("Mid-C") trading hub in north central Oregon. We used current reported forward prices for the months of March 2010 through 2012, and assumed simple annual escalation for subsequent months. We did not include the value of any outstanding invoices (accounts payable) that the seller would likely add to the collateral requirement for the purpose of simplicity. We also assumed that Avista would have a Collateral Threshold of zero due to its non-investment grade rating at the time. The required collateral was calculated assuming a 5 year look-ahead and a $250/kw maximum amount consistent with the PG&E methodology.

With respect to capacity charges, we included them as a component of PPA cost. This is a deviation from the PG&E methodology which relies on variable PPA costs (fuel and VOM) only. Inclusion of capacity charges is necessary to make a valid comparison to market prices since i) the market prices referenced are for firm deliveries at Mid-C and ii) the capacity charges contribute to the buyer's cost and therefore raise the probability of buyer default to the seller and must be considered by the seller in determination of collateral for the buyer.

Results for the first few months of the collateral calculation are shown in Table 1 below.

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Table 1 –Collateral Calculation for a Generic 275 MW PPA

	Market Prices		Generic 275 MW PPA									
	A	B	C	D	E	F	G	H	I	J	K	L
Month	Market Gas Price (1) ($/MMBtu)	Market Power Price (2) ($/MWh)	Energy (3) (MWh)	Fuel Cost (4) ($/MWh)	Non-Fuel Variable Charges (5) ($/MWh)	Capital + O&M Charges (6) ($/kw-mo)	Capital + O&M Charges (6) ($/MWh)	Cost of Power ($/MWh)	Contract Over (Under) Market ($/MWh)	Contract Over (Under) Market ($ million)	Sum of Next 60 Months Contract Over (Under) Market ($ million)	Collateral Required (7) ($ million)
Jun-07	$6.93	$43.62	198000	$50.40	$2.094	$6.713	$9.324	$61.82	$18.20	$4	$112	$69
Jul-07	$6.03	$47.21	204600	$43.81	$2.094	$6.713	$9.023	$54.92	$7.71	$2	$113	$69
Aug-07	$5.18	$46.87	204600	$37.65	$2.094	$6.713	$9.023	$48.77	$1.90	$0	$113	$69
Sep-07	$4.64	$48.63	198000	$33.73	$2.094	$6.713	$9.324	$45.14	($3.48)	($1)	$113	$69
Oct-07	$5.69	$55.05	204600	$41.36	$2.094	$6.713	$9.023	$52.48	($2.57)	($1)	$114	$69
Nov-07	$7.02	$58.59	198000	$51.07	$2.094	$6.713	$9.324	$62.49	$3.89	$1	$114	$69
Dec-07	$6.91	$59.55	204600	$50.25	$2.094	$6.713	$9.023	$61.37	$1.82	$0	$115	$69
Jan-08	$6.84	$68.76	204600	$49.73	$2.200	$6.866	$9.228	$61.16	($7.59)	($2)	$118	$69
Feb-08	$7.75	$66.57	191400	$56.33	$2.200	$6.866	$9.864	$68.39	$1.82	$0	$121	$69
Mar-08	$8.69	$69.88	204600	$63.15	$2.200	$6.866	$9.228	$74.58	$4.70	$1	$123	$69
Apr-08	$9.00	$85.28	198000	$65.45	$2.200	$6.866	$9.536	$77.18	($8.10)	($2)	$128	$69
May-08	$10.41	$48.88	204600	$75.67	$2.200	$6.866	$9.228	$87.10	$38.22	$8	$123	$69
Jun-08	$10.74	$17.21	198000	$78.05	$2.200	$6.866	$9.536	$89.78	$72.57	$14	$112	$69
Jul-08	$11.90	$54.76	204600	$86.49	$2.200	$6.866	$9.228	$97.92	$43.17	$9	$105	$69
Aug-08	$8.05	$63.50	204600	$58.55	$2.200	$6.866	$9.228	$69.98	$6.48	$1	$104	$69
Sep-08	$7.13	$51.80	198000	$51.81	$2.200	$6.866	$9.536	$63.55	$11.75	$2	$102	$69
Oct-08	$6.10	$46.60	204600	$44.32	$2.200	$6.866	$9.228	$55.75	$9.15	$2	$100	$69
Nov-08	$6.07	$46.14	198000	$44.10	$2.200	$6.866	$9.536	$55.84	$9.69	$2	$99	$69
Dec-08	$6.20	$52.78	204600	$45.07	$2.200	$6.866	$9.228	$56.49	$3.71	$1	$99	$69
Jan-09	$5.68	$36.97	204600	$41.29	$2.257	$6.969	$9.367	$52.91	$15.94	$3	$97	$69
Feb-09	$4.49	$36.54	184800	$32.61	$2.257	$6.969	$10.371	$45.24	$8.70	$2	$99	$69
Mar-09	$3.80	$28.89	204600	$27.65	$2.257	$6.969	$9.367	$39.27	$10.38	$2	$100	$69
Apr-09	$3.41	$19.16	198000	$24.76	$2.257	$6.969	$9.679	$36.70	$17.53	$3	$100	$69
May-09	$3.02	$20.31	204600	$21.94	$2.257	$6.969	$9.367	$33.57	$13.25	$3	$100	$69

(1) Stanfield price based on AECO actuals through 2/2/2010, forwards through January 2012, 2% escalation thereafter, plus plus FTHLs/GTN transport.
(2) Mid-C price based on actuals through 2/2/2010, forwards through December 2010, 2% escalation thereafter
(3) Assumes 275 MW capacity, 100% capacity factor
(4) Includes 3.852% Washington fuel use tax
(5) Based on Lancaster PPA 1998 starting price plus actual GDP-IPD through 2009, 2% escalation thereafter
(6) Based on Lancaster PPA 1998 starting prices plus actual GDP-IPD through 2009, 2% escalation thereafter.
(7) Assumes cap of $250/kw

Results show that the generic PPA would have been over market in nearly every month. Avista would have had to post approximately $69 million in collateral at the time of PPA execution and maintain it during the subsequent months shown. The $69 million amount (column L) is less than the 60 month mark-to-market value (column K) due to the effect of the $250/kw collateral limit. This trend continues through nearly the entire forecast term (17 years). Figure 1 below illustrates the relationship between market power price, PPA price and the required collateral over the first 5 years of the calculation.

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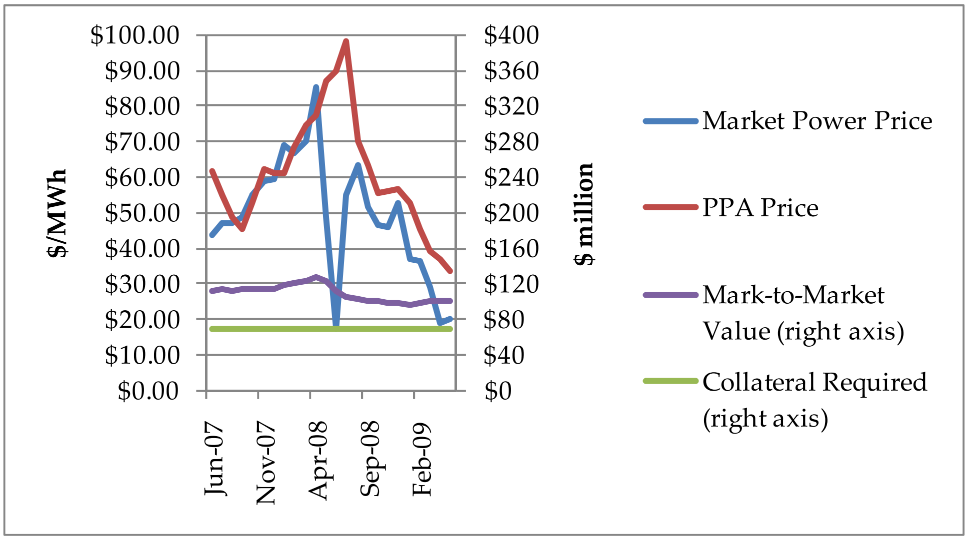
Figure 1 – Prices and Required Collateral for a Generic 275 MW PPA



The collateral amount calculated above is for one specific point in time based on one specific set of gas and power price forecasts. During the term of an actual PPA, this calculation would be repeated at least monthly based on the then current market prices and forecasts. Market prices, or just the market sentiment about prices as reflected in the seller's then current forecasts, could change significantly from month to month. Collateral requirements may increase or decrease as a result. In this example, Avista's collateral requirement is already limited to $69 million by the $250/kw cap. However, if this cap was not in place, and should collateral requirements increase due to changed forward market prices, the seller could require immediate posting of additional collateral amounts by Avista. Failure to post additional collateral within a few days could result in PPA termination by the seller and imposition of termination damages.

8.3. Summary Concerning Credit and Collateral Requirements

In summary, several draft form PPAs that were in use during the 2005-2008 period required posting of collateral by the Buyer upon a credit downgrade event and/or if the PPA prices were significantly higher than then forecast market prices ("over-market"). Avista was sub-investment grade during mid-2007. If a seller had been willing to transact with Avista at the time, Avista may have had to post approximately $69 million in collateral for a CCCT based PPA with a typical heat rate and non-fuel charges similar to the Lancaster PPA assuming that the seller's then power price forecast equaled actual reported prices for the period. Avista returned to investment grade in early 2008 which would have reduced the probability of having to post collateral from that point forward. Nevertheless, posting of approximately $69 million of collateral initially, and the requirement to rapidly post additional collateral as necessary during the term, would have posed significant additional cost to Avista relative to the Lancaster PPA.

END OF REPORT

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

Business Practice

Line and Load Interconnection Procedures, Version 2

Posted: September 4, 2007

Effective: September 4, 2007

Table of Contents

1 Policy Reference

This Business Practice implements the following sections of the Transmission Services Open Access Transmission Tariff (OATT) and the 2006 Transmission & Ancillary Service Rate Schedules (Rate Schedules), or their successors.

1.1 OATT Sections 13.5, 15.2, 15.4, 17.6.1, 19, 28.2, 29.4, 29.6,32, Attachment D, and Attachment J of Transmission Services' OATT

1.2 "Technical Requirements for Interconnection to the BPA Transmission Grid", BPA Document Number DOE/BP-3624, 15 June 2005

1.3 Customer Service Policy, July 1, 1984

2 Definitions

Unless otherwise defined herein, capitalized terms are defined in Transmission Services' OATT, Rate Schedules, or Federal Energy Regulatory Commission (FERC) OASIS Status Code Definitions or their successor.

2.1 Business Day: Any weekday (Monday through Friday) that is not a United States Federal Holiday.

2.2 Close of Business: 5:00 p.m. Pacific Prevailing Time.

2.3 Environmental Study Agreement: An agreement between the customer and BPA identifying the National Environmental Policy Act (NEPA) required documentation BPA will produce and customer terms for compliance, including participation in public meetings, requirement to exercise due diligence in completing required NEPA studies and activities, and terms for termination and or severance of studies, processes. Federal law requires that BPA comply with NEPA and prohibits BPA from committing to construction agreements for interconnections until NEPA requirements are satisfied.

2.4 Federal Holidays: Days when the Federal Government is closed for business and include New Year's Day, the birthday of Martin Luther King, Jr., (observed on the third Monday of January) the birthday of George Washington (observed on the third Monday of February), Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans Day, Thanksgiving Day, and Christmas Day.

2.5 Interconnecting Customer (Customer): A Customer who is requesting a line or load interconnection to BPA's system.

2.6 Lines and Loads Interconnection Request (LLIR): A request submitted to Transmission Services on BPA Form F6420.25, Transmission Lines and Loads Connection Information.

2.7 Load Growth: Load added to an existing Network Integration (NT) customer's system as a result of increased customer load or transfer of load from another NT customer.

2.8 Network Load Transfer: Transfer of load from one NT customer to another NT customer.

2.9 New Network Load: Load added to an existing NT customer's system as the result of:

2.9.1 Annexation

2.9.2 Condemnation

2.9.3 Merger

2.9.4 Conversion of Point-to-Point (PTP) Service Agreement to NT Service Agreement

2.9.5 Reduction to Customer Served Load

2.9.6 Request by a Network customer to designate a particular load at discrete points of delivery as Network Load, when the Network Customer had previously elected not to designate that load as Network Load

2.10 Technical Studies: Line and Load Interconnection System Impact Study (LLISIS) and Line and Load Interconnection Facilities Studies (LLIFS).

3 Line and Load Interconnection Request (LLIR)

3.1 Point-to-Point (PTP) Transmission Service

3.1.1 All PTP customers, and other entities seeking a transmission system interconnection without associated PTP or NT Transmission Service, must submit a LLIR on BPA Form F6420.25 when requesting a new or modified transmission system interconnection. Section 5 provides information on where to submit the request.

3.1.2 If the PTP customer intends to link its LLIR with a request for PTP Transmission Service it must submit Transmission Service Request (TSR) on the same calendar day of submission of the LLIR, using the new interconnection point requested in the LLIR as the POD in the TSR. (See Application Process for Transmission Service Business Practice.)

3.1.3 The TSR must state the request is linked to an Interconnection Request in the Customer Comments field.

3.1.4 A TSR at an interconnection point where no substation yet exists must include a geographical reference point identified as "NEWPOINT" in the Source or Sink field.

3.2 Network Integration (NT)Transmission Service

3.2.1 All NT customers must submit a LLIR on BPA Form F6420.25 when requesting a new or modified transmission system interconnection. Section 5 of this Business Practice provides information on where to submit the request.

3.2.2 Upon evaluation of a LLIR to serve Network Load Growth or a Network Load Transfer, Transmission Services may reclassify the

LLIR as New Network Load and require the NT customer to submit a TSR pursuant to Step 3.2.3 below.

3.2.3 NT customers requesting new facilities to serve New Network Load must submit TSR under the OATT and compete for Available Transfer Capability (ATC). See the Application Process for Transmission Service Business Practice.

3.2.3.1 A TSR at an interconnection point where no substation yet exists must include a geographical reference point identified as “NEWPOINT” in the Source or Sink field.

3.2.4 NT customers requesting facilities to serve Load Growth are exempt from making a TSR under the OATT and from competing for ATC.

3.2.5 NT customers wanting to designate new Network Resources in their NT Service Agreements must apply for NT Transmission Service. See the Application Process Business Practice.

3.2.6 If the NT customer intends to link its LLIR with a request for NT Transmission Service it must state in the Customer Comment Field of the TSR that the request is linked to an Interconnection Request.

3.3 Consistent with applicable law Transmission Services requires compensation from the Customer to mitigate stranded costs if a new transmission system interconnection will bypass or otherwise strand investment in an existing Transmission Services’ facility.

3.4 Table 1 below is a summary for how interconnections requests are evaluated:

Table 1

Circumstance	LLIR	Application Tr Services (including Deposit) & Tr Queue Postings Required	Direct Assignment Guidelines Apply	"OR Test" May Apply	Study Cost Responsibility	Funding of Network Facilities	Tr Credits Apply
PTP, Merchant Line or New NT Service	Yes	Yes	Yes	Yes	Customer	Customer	Yes
New Network Load	Yes	Yes	Yes	Yes	Customer	Customer	Yes
Load Growth for NT Service	Yes	No	Yes	No	Transmission Services[1]	Transmission Services[2]	N/A
Convenience Point of Interconnection	Yes	Yes, when applicable	N/A	N/A	Customer	Customer	No
New Network Resource	Yes	Yes	Yes	Yes	Customer	Customer	Yes
Network Load Transfer	Yes	No	Yes	No	Transmission Services[3]	Transmission Services	N/A

[1] Significant "What if" analysis and studies requested by the customer will be done at the customer's expenses.

[2] Network Upgrades needed to accommodate load growth that is solely caused by a single, large load will be financed by the Customer in exchange for transmission credits.

[3] Id.

4 Advance Funding Criteria

4.1 Customers requesting a transmission interconnection for new service or to serve New Network Load or a Convenience Point of Delivery are required to provide advance payment to Transmission Services upon execution of a Technical Study agreement.

4.2 Where applicable, residual advanced funds shall be progressively applied to the remaining studies required. Any outstanding funds remaining at the completion of the studies will be refunded to the Customer.

5 Submission Procedures

To request a transmission interconnection, the Customer must submit its LLIR by one of the following mechanisms below:

5.1 US Postal Service

Bonneville Power Administration
Transmission Marketing and Sales – TSE-TPP-2
P.O. Box 61409
Vancouver, WA 98666-1409

5.2 Overnight Delivery Service

Bonneville Power Administration
Transmission Marketing and Sales – TSE-TPP-2
7500 NE 41st Street
Suite 130
Vancouver, WA 98662

5.3 Facsimile (fax): (360) 619-6940

5.3.1 A cover page specifying the number of requests and the total number of pages should accompany requests submitted by fax.

5.3.2 Transmission Services is not responsible for the failure of fax transmissions.

5.4 Email

5.4.1 Submit LLIRs to: txrequests@bpa.gov.

5.4.2 Important: Enter "LLIR" as the Subject Line of the email.

5.4.3 Transmission Services will not accept an LLIR that is sent by email to other Transmission Services email addresses. Emails sent to other email addresses will not be entered into the Interconnection Queue.

5.5 An LLIR transmitted by telefax or email must be followed by a hard copy to be received by Transmission Services within five Business Days of the faxed or emailed request. If the hardcopy is not received, the request will be removed from the Interconnection Queue.

6 Processing the LLIR

6.1 Queue time of an LLIR shall be established by the timestamp when Transmission Services receives the LLIR determined as follows:

6.1.1 Email – the time that the email is received in the TxRequest mailbox

6.1.2 Fax – the time stamp on the fax

6.1.3 Mail –the time stamp when the request is opened

6.1.4 Overnight Delivery Service – time when the request is delivered to the BPA mailroom

6.2 Transmission Services will post the LLIR information to its Interconnection Queue located on Transmission Services' web site at: http://www.transmission.bpa.gov/Business/Reserve_and_Schedule_Transmission/girequests.cfm

6.3 The type of service will specify “Line and Load Interconnection” if no separate transmission service is requested. In such case, only the POD associated with the LLIR will be posted.

6.4 Within 15 Business Days following receipt of the LLIR , Transmission Services will provide the Customer with:

6.4.1 Acknowledgement of receipt of the LLIR

6.4.2 Notification of any deficiencies in the LLIR

7 Line and Load Interconnection System Impact Study (LLISIS)

7.1 Within 30 calendar days following receipt of a valid LLIR, Transmission Services will provide the Customer with:

7.1.1 LLISIS agreement

7.1.2 A non-binding, good faith estimate of the costs, if applicable.

7.1.3 Estimated timeframe for completing the LLISIS

7.2 Within 30 calendar days following receipt of a valid LLIR, Transmission Services may provide the Customer with:

7.2.1 Notification that an environmental study is required, if applicable

7.2.2 Environmental Study Agreement, if applicable

7.2.3 If Transmission Services determines that an LLISIS is not necessary it will provide the Customer with an LLIFS agreement pursuant to Section 9 below.

7.3 No later than 15 Business Days after receipt of the LLISIS agreement, the Customer will provide Transmission Services the following:

7.3.1 Executed LLISIS agreement

7.3.2 LLISIS advanced funds equal to the estimate provided by BPA Transmission Services, if applicable

7.3.3 Executed Environmental Study Agreement, if applicable

7.3.4 Environmental Study Advance Funds, if applicable

7.4 Transmission Services will use reasonable efforts to complete the LLISIS no later than 60 calendar days from the receipt of the executed LLISIS agreement.

7.5 Upon completion of the LLISIS Transmission Services will provide the Customer with a written LLISIS report and supporting documentation.

8 NEPA Study

8.1 If an environmental review is required, Transmission Services will offer the Customer an Environmental Study Agreement (ESA) when the scope is determined.

8.2 The ESA may be modified as the Customer's request is refined and additional environmental review tasks are identified.

8.3 If all other requirements have been met, upon completion and approval to proceed pursuant to the decision reached under the ESA Transmission Services will offer the Customer a construction agreement, if needed.

9 Line and Load Interconnection Facilities Study (LLIFS)

9.1 Within 30 calendar days after a completed LLISIS report Transmission Services will provide the Customer with the following:

9.1.1 LLIFS agreement

9.1.2 A non-binding, good faith estimate of the costs, if applicable.

9.1.3 Estimated timeframe for completing the LLIFS

9.1.4 Notification that an environmental study is required, if applicable

9.1.5 Environmental Study Agreement, if applicable

9.2 No later than 15 Business Days after receipt of the LLIFS agreement, the Customer will provide Transmission Services the following:

9.2.1 Executed LLIFS agreement

9.2.2 LLIFS advance funds equal to the estimate provided by BPA Transmission Services if applicable

9.2.3 Executed Environmental Study Agreement, if applicable

9.2.4 Environmental Study Advance Funds, if applicable

9.3 Transmission Services will use reasonable efforts to complete the LLIFS within 60 calendar days of receipt of the executed LLIFS agreement.

9.4 Upon completion of the LLIFS Transmission Services will provide the Customer with the written LLIFS report.

9.5 Upon completion of the LLIFS, Transmission Services will refund any outstanding advance funds.

10 Construction Agreement

10.1 Transmission Services will offer the Customer a construction agreement within 60 calendar days of the later of:

10.1.1 Completion of any NEPA process, if applicable, or

10.1.2 Completion of the LLIFS report.

10.2 No later than 15 Business Days after receipt of the construction agreement, the Customer will provide Transmission Services an executed construction agreement. Failure to return the construction agreement within the timeframe may result in the Customer's request being subject to re-consideration of the construction and energizing timelines.

11 Related Business Practices

Transmission Services' Business Practices are available on its web page at http://www.transmission.bpa.gov/Business/Business_Practices/default.cfm. See the following related Business Practices.

11.1 Application Process for Transmission Service

11.2 Guidelines for Direct Assignment Facilities

12 Version History

Version Date	Status/Summary
9/4/07, V2	The following revisions have been made: • Incorporated CBPI Bulletin 19 – Processing of Long-Term Firm Point-to-Point (PTP) Transmission Service Requests with OASIS Implementation, Version 4, CBPI Bulletin 27 – Processing Network Integration Transmission Services (NT) Applications • Step 3.1.2 – Deleted "an Application for" and replaced with "Request TSR" and replaced "within 24 hours" with "on same calendar day" because Transmission Services must receive the request for transmission service and interconnection on the same calendar day. • Step 3.1.3 – Added language requesting customer to identify in its TSR under the customer comment field that the request is linked to the LLIR. • Step 3.1.4 – Added language instructing customer to insert "NEW POINT" in the TSR if there is no interconnection point. • Step 3.2.3.1 – Added language instructing customer to insert "NEW POINT" in the TSR if there is no interconnection point. • Step 3.2.6 - Added language instructing customer to identify in its TSR under the customer comment field that the request is linked to the LLIR. • Step 3.4 - Table 1 revisions: o Footnote 1 has been reworded to clarify that when a customer requests Transmission Services to study significant scenarios related to line/load interconnections, they are responsible for the study costs associated with generating these scenarios. o Footnote 2 has been added to clarify that if a Network Upgrade is needed to accommodate load growth due to a single, large load; the customer will be responsible for financing the cost of the upgrade and will be repaid with transmission credits.

	<u>The following sections and/or steps of this Business Practice were revised to incorporate non-CBPI related revisions:</u> • Step 5.4.2 – Deleted note that Customer will be notified automatically. BPA Cyber Security removed this function for security reasons. • Step 8.1 – Deleted timeline for when Transmission Services will offer customer an Environmental Study Agreement. • Deleted Attachment A – Customer should refer to the Technical Requirements for Interconnection to the BPA Transmission Grid", BPA Document Number DOE/BP-3624, 15 June 2005, page 43. <u>Transmission Services also replaced the following terms throughout the Business Practice:</u> • *TBL* is now referred to as *Transmission Services* • *Section* is now referred to as *Step* • *Tariff* is now referred to as *OATT*
3/2/07, V1	• This document provides instructions for customers requesting a new line and/or load interconnection. • Instructions for Point to Point (PTP) Transmission Service requests are provided separately from those for Network Integration (NT) Transmission Service requests to provide product-specific guidance on line or load interconnections associated with Open Access Transmission Services offered by BPA Transmission Services. • This document also provides information on how the interconnection facilities and associated studies will be funded, and how transmission availability is considered. Procedures for requesting new generation interconnections will not change. (See Large Generation Interconnection Business Practice).

Department of Energy

Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666-1409

FILE COPY
F/I - Kenny

TRANSMISSION SERVICES

September 10, 2009

In reply refer to: TSE/TPP-2

Mr. Kenneth Dillon
Transmission Contracts Engineer
Avista Corporation
1411 East Mission, MSC-16
Spokane, WA 99220-3737

Dear Mr. Dillon:

Avista Corporation (Avista) submitted a Line and Load Interconnection request to the Bonneville Power Administration (BPA) on August 10, 2009, via E-mail and BPA entered it in the Line and Load Interconnection Queue as Request No. L0311 (Request). The Request seeks interconnection to BPA's Lancaster 230kV Substation in Kootenai County, Idaho.

BPA acknowledges receipt of Avista's Request and has determined that there are no deficiencies. BPA will be contacting Avista within 30 Business Days to arrange for a kickoff meeting.

If you have any questions, please contact me at (360) 619-6015, or Shari Sundeen, Line and Load Interconnection Administrator, at (360) 619-6045.

Sincerely,

Toni L. Timberman

Toni L. Timberman
Senior Transmission Account Executive
Transmission Sales

Bonneville Power Administration Interconnection Request Queue

Note: Requests with queue positions lower than 200 were submitted prior to adoption of LGIP/SGIP.

Request Number	Request Date	Project Name	Requestor	Point of Interconnection	Status	Connection Type	In Service Date
G0390	11/02/2009 12:02			TBA	RECEIVED	GI	11/01/2013
G0388	11/02/2009 10:45			BPA's Idahome Substation	RECEIVED	GI	10/15/2010
G0386	10/28/2009 8:47			BPA's Pomeroy Substation	RECEIVED	GI	12/01/2011
G0387	10/26/2009 15:49			Midstate Electric 24.9kV distribution system at Christmas Valley Substation	RECEIVED	GI	12/31/2009
G0385	10/08/2009 11:07			Midstate Electric's Fort Rock Substation at 115 kV□ at the 115 kV bus	RECEIVED	GI	12/01/2011
G0383	10/06/2009 9:06			Holcomb 115 kV Substation	RECEIVED	GI	12/31/2012
G0384	10/06/2009 9:06			Bandon 115 kV Substation	RECEIVED	GI	6/01/2011
G0382	9/21/2009 14:51			At BPA's Midway 230 kV substation	RECEIVED	GI	10/30/2012
G0381	9/21/2009 9:19			On Harney Electric Cooperative's 115 kV transmission system approximately 30 miles south of Burns, Ore.	RECEIVED	GI	12/31/2012
G0380	9/15/2009 9:40			BPA's Substation at Slatt, Ore.	RECEIVED	GI	5/01/2014
G0379	9/02/2009 15:30			Midstate Electric 24.9 kV distribution system	RECEIVED	GI	7/30/2010
L0316	8/28/2009 14:25	McNary Substation	PacifiCorp	BPA's McNary Substation	RECEIVED	LL	10/01/2011
L0314	8/27/2009 9:25	Merchant Txm Line-Townsend	Tonbridge Power Inc.	BPA Colstrip line at or near Townsend, MT	RECEIVED	LL	10/01/2013
L0315	8/27/2009 9:25	Merchant Txm Line-Garrison	Tonbridge Power Inc.	BPA Colstrip 500kV Line at Garrison Substation	RECEIVED	LL	10/01/2013
G0378	8/27/2009 9:22			BPA's Substation at Shelton, Wash.	STUDY	GI	12/31/2012
L0313	8/20/2009 11:34	Bridge Substation	Raft River Rural Electric	BPA's Bridge Substation	RECEIVED	LL	11/01/2010
L0311	8/10/2009 16:52	Lancaster Substation	Avista Corp	Lancaster 230	RECEIVED	LL	9/01/2012
L0312	8/10/2009 10:48	Bell-Boundary #1 230 kV	Inland Power and Light	Bell-Boundary #1 transmission line.	RECEIVED	LL	10/01/2011
G0376	8/06/2009 10:09			Midstate Electric 24.9 kV distribution system	RECEIVED	GI	7/30/2010
G0377	8/06/2009 10:09			Midstate Electric 24.9 kV distribution system	RECEIVED	GI	7/30/2010
L0310	7/30/2009 14:52	Mount Adams Substation	Yakama Power	Feeder #2 out of BPA's Alfalfa Substation	RECEIVED	LL	12/01/2009
G0375	7/14/2009 13:18			BPA's proposed Wood Creek 230 kV Substation	RECEIVED	GI	10/01/2011
G0374	6/30/2009 9:53			BPA's 115 kV Goshen-Palisades Transmission Line approximately 20 miles east of Goshen Substation	RECEIVED	GI	12/31/2010
G0373	6/29/2009 10:27			BPA's 230 kV transmission line between Libby and Haskill.	RECEIVED	GI	4/30/2012
G0371	6/03/2009 14:15			TBA	RECEIVED	GI	12/31/2012
G0372	6/03/2009 14:15			TBA	RECEIVED	GI	12/31/2012
G0369	6/02/2009 12:55			BPA's Red Mountain Substation.	RECEIVED	GI	12/31/2012