Exhibit V

Avoided Costs Schedule

Table V.1 provides an annual schedule for 2004 – 2023 of forecasted electricity prices, consistent with the August 2003 Least Cost Plan Update, reflecting the market-based forecasts of natural gas prices for 2004 – 2005 as used in the Power Cost Only Rate Case, Docket No.UE-031725. The forecasts are based on assumptions about natural gas prices, regional demand, new resource development, and developer financing costs that are consistent with assumptions made in the August 2003 Least Cost Plan Update. The estimated prices are derived using the AURORA model and do not include system integration, shaping, or transmission costs. Table V.2 provides the nominal price forecast on a monthly basis for flat load.

Note: This schedule is an estimate based on generic assumptions for loads and resources in the West for the next twenty years. The purpose of the schedule is only to provide general information to potential bidders. Proposals will be evaluated and ranked against each other based on the criteria listed in the Request for Proposals from All Generation Sources**.**

Table V.1 (Nominal $/MWH)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Nominal $/MWH	37.99	38.78	38.45	38.66	38.58	39.73	40.36	41.90	44.65	45.54
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Nominal $/MWH	47.32	45.39	45.39	47.59	51.43	53.16	55.27	53.65	55.73	58.08

Table V.2 (Nominal $/MWH)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2004	39.18	39.40	36.95	33.33	25.43	24.47	38.75	45.32	47.74	42.10	41.22	41.99
2005	41.50	39.48	37.60	34.90	27.75	27.04	37.02	42.33	46.03	42.19	44.07	45.40
2006	37.32	35.83	32.40	32.18	27.90	26.84	36.67	44.08	48.97	45.18	45.81	48.00
2007	36.95	35.90	32.29	32.28	27.65	27.47	36.63	44.61	50.03	45.62	45.82	48.46
2008	35.65	34.20	31.32	30.78	27.06	27.40	36.05	45.29	58.71	44.47	44.92	47.10
2009	35.72	34.39	31.38	30.98	27.45	27.54	36.17	51.41	63.56	44.68	45.43	47.75
2010	36.13	35.37	31.29	31.24	28.02	27.98	37.10	54.90	63.73	44.89	45.56	47.86
2011	36.27	36.17	32.52	31.43	28.20	28.67	38.21	65.52	64.01	45.93	46.29	49.16
2012	37.58	37.14	33.37	32.52	29.42	29.42	37.94	74.75	76.52	48.28	47.87	50.75
2013	38.78	37.90	34.17	33.03	29.32	29.17	39.86	81.65	77.17	46.28	48.01	50.61
2014	38.03	38.32	34.64	32.28	29.14	28.89	37.89	94.78	89.42	46.28	47.32	50.22
2015	39.19	38.92	34.17	32.79	29.61	29.18	36.97	75.70	80.43	46.59	48.92	51.91
2016	40.10	40.52	35.46	34.26	30.63	31.01	38.16	77.11	66.34	47.36	50.29	53.10
2017	42.41	41.61	36.37	35.50	32.77	32.09	39.98	83.25	70.12	49.02	52.12	55.17
2018	41.83	42.20	36.61	34.53	31.57	31.35	40.16	110.53	92.30	50.36	51.02	53.93
2019	44.23	45.03	38.74	36.12	33.06	33.02	43.21	103.23	96.81	54.21	53.33	56.37
2020	47.69	49.25	41.20	38.72	36.17	35.43	44.35	99.24	95.07	57.97	57.44	60.47
2021	46.17	45.46	40.21	37.59	33.72	34.77	43.07	97.47	91.07	59.48	55.65	58.46
2022	49.51	48.23	41.19	38.94	35.46	35.86	44.33	107.95	86.07	61.92	57.35	61.14
2023	51.51	48.71	42.48	40.09	37.55	36.63	46.07	107.63	94.20	69.39	59.09	62.64

KEY ASSUMPTIONS FOR THE AURORA MARKET POWER PRICE FORECAST

Natural Gas

In anticipation of the August 2003 Least Cost Plan Update, PSE determined that a review of the PIRA gas-price forecast was warranted in light of the gas market's volatility in early 2003, which resulted in a significant run-up in near-term gas prices. Growing concern in the industry regarding an imbalance in supply and demand suggested that near-term prices would stay relatively high until equilibrium in the markets was re-established.

Upon reviewing additional PIRA gas-price data (including previously missing years), the underlying assumptions regarding the availability of new resources at certain high gas-price points resulted in a return to lower-equilibrium price levels. These lower price levels reflect the cyclical pricing from boom-and-bust gas-supply development (as opposed to the smooth price curve previously developed from the data). Revised annual gas-price projections were developed ("PIRA-Revisited" forecast) using the cyclical pattern from new PIRA data, including the outer years of the planning period (2015 to 2023).

PSE then acquired access to Cambridge Energy Research Associates' (CERA) December 2002 long-range gas-price scenarios for North America, provided under CERA's North American Gas and Power Advisory Service. CERA's long-term, regionally specific price scenarios provide average annual market prices by supply basin or trading hub through the year 2020. PSE extended the CERA data from 2020 to 2023 based on the average annual gas-price change from 2006-2020. The four available CERA supply/price scenarios were reviewed for applicability based on the underlying economic and supply-development assumptions of each scenario. CERA's four scenarios are described as follows:

- **Rear-View Mirror** - The economy recovers from the recession in late –2002(3?), but economic uncertainty remains, and a crisis of confidence emerges.
- **Technology Enhanced** - The recession proves to be mild and short-lived, and the North American economies return to a sustained period of economic growth as new technological developments abound.
- **World in Turmoil** - The current recession is not a short detour. Instead, the North American economy mirrors the recent performance of the Japanese economy.

- **Shades of Green** - The economy recovers steadily and the environment becomes an increasing concern. Some international agreements are reached to control greenhouse-gas emissions.

Two scenarios, World in Turmoil and Technology Enhanced (including their associated supply- and infrastructure-development assumptions) were judged the most apt descriptors of the range of economics in the western U.S. markets affecting PSE. In particular, these two scenarios anticipate more aggressive development of new resources in the Western Canadian Sedimentary Basin of Alberta and British Columbia, and the emergence of gas supplies from the McKenzie Delta prior to the end of the decade.

Rather than relying on a single forecast or scenario to predict long-term gas prices, PSE elected to average four of the known forecasts used in the region, including the two previously mentioned CERA scenarios. The four forecasts are:

- NPCC Medium Gas Price Forecast
- PIRA "Revisited" (including cyclical shaping data)
- CERA - World in Turmoil Scenario
- CERA - Technology Enhanced Scenario

While the average of the four gas-price scenarios provided an adequate representation of long-term regional gas prices based on objective, independent research and analysis, PSE determined that none of the four scenarios (or their average) adequately considered the recent run-up in market prices. Such consideration would have shown a more profound price impact on near-term resource planning. Therefore, the forecasted gas-price results for 2004 were replaced with currently available market-price quotes from June 2003.

In order to consider the impacts of extremes in gas pricing, PSE chose a High Price forecast (defined as the NPCC Medium Price Forecast) and a Low Price forecast (defined as the PIRA straight-line forecast used as the base-case forecast in the April 30, 2003, LCP analyses).

The four forecast scenarios, the resulting average of the four, and the adopted High and Low price strip for the three main trading hubs affecting PSE's supply costs are depicted in Charts V.1 to V.3:

Chart V.1
Sumas Gas Price ($/Dth)

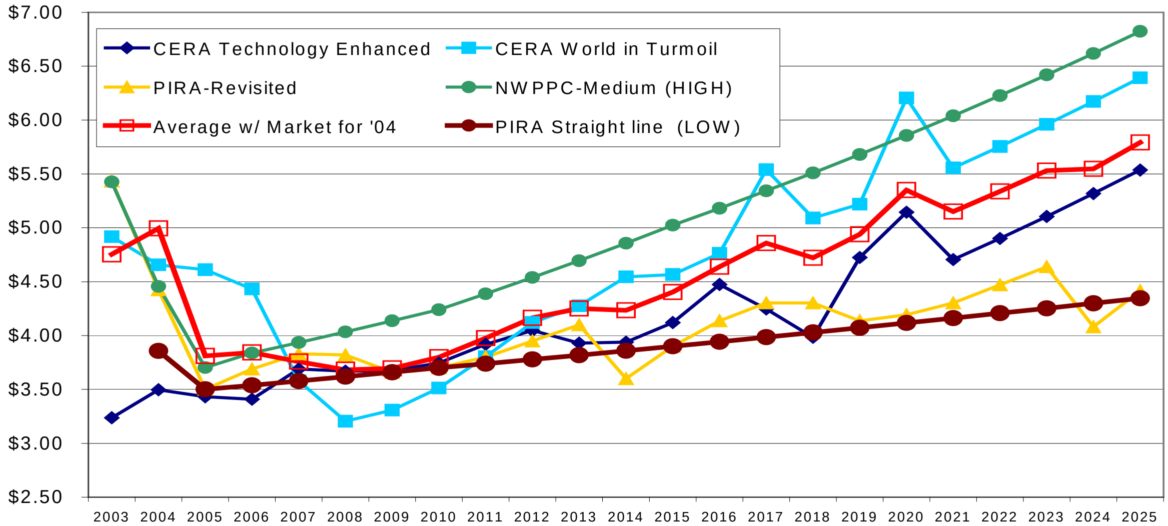


Chart V.2
AECO Gas Price ($/Dth)

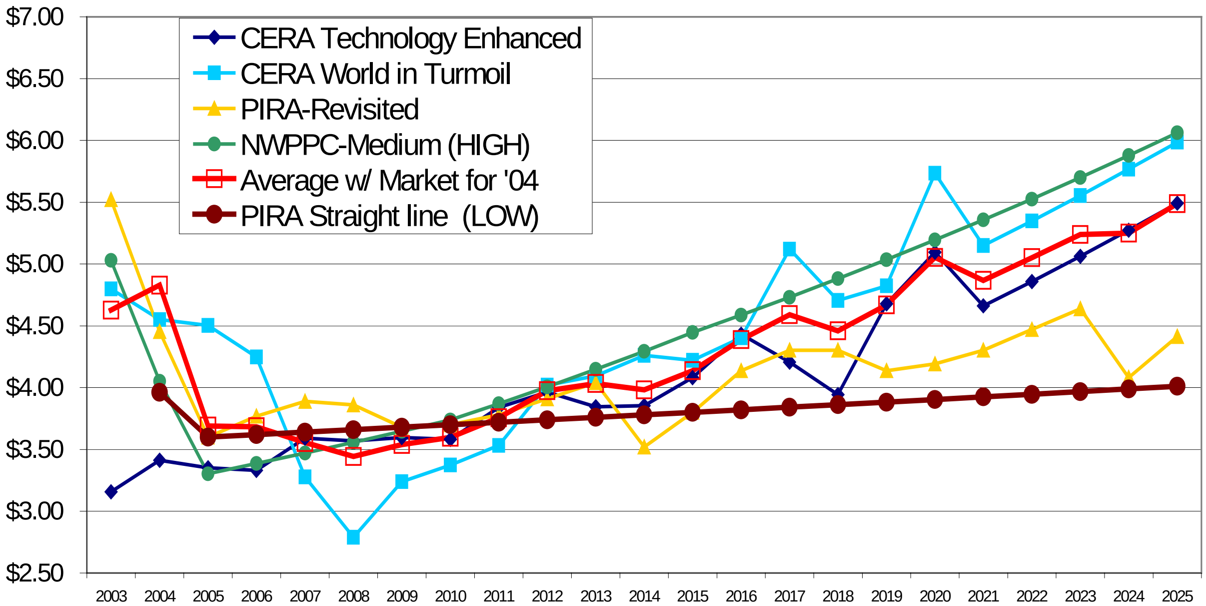
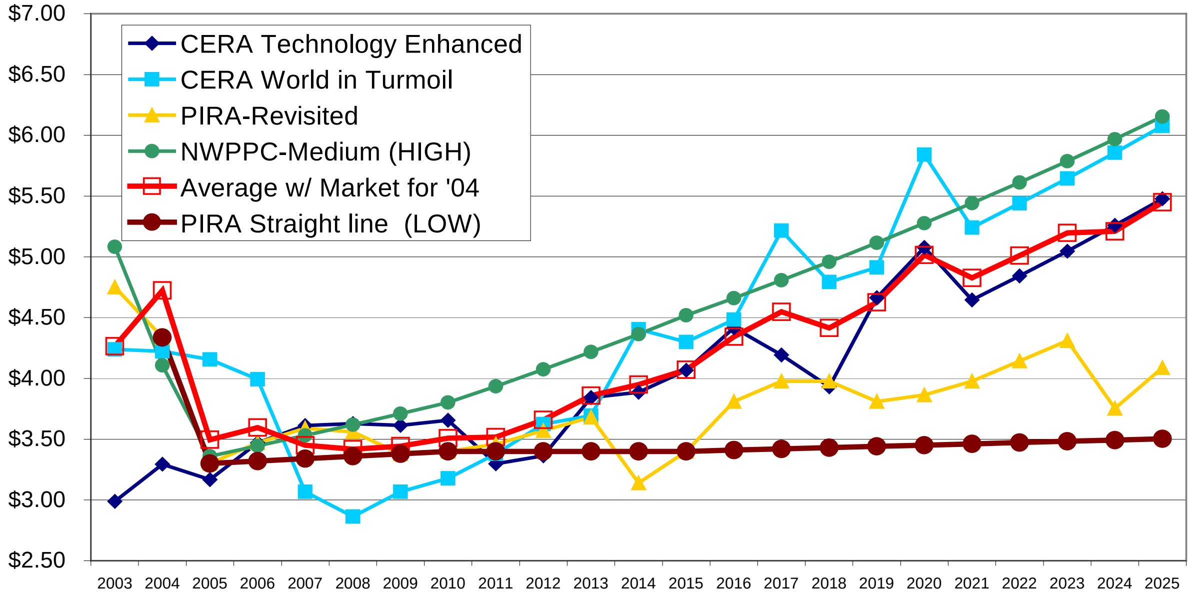


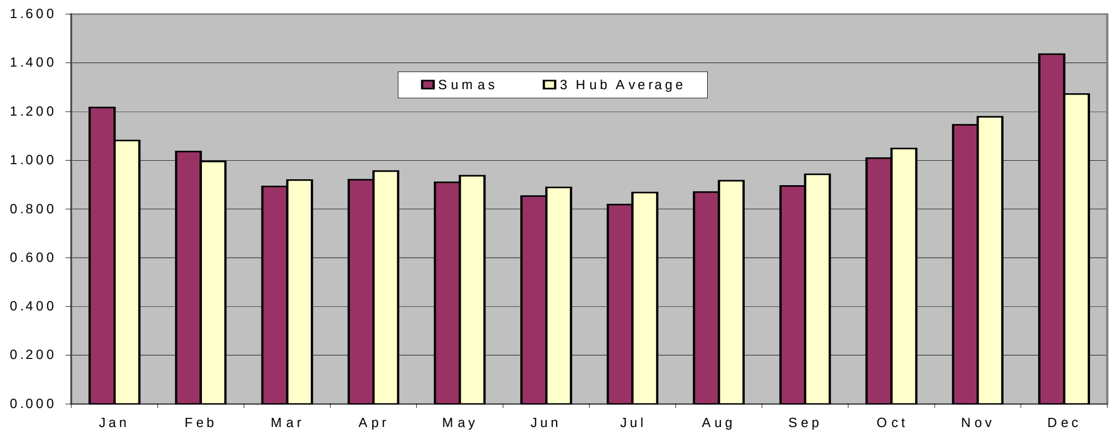
Chart V.3
Rockies Gas Price ($/Dth)



As discussed previously, PSE considered a number of gas-price forecast scenarios and sources including PIRA, CERA, and the NPCC. Each annual price requires that a monthly shape factor be applied to generate 12 monthly prices. The monthly shape factors are the average of the three Northwest hubs – Sumas, AECO, and Rockies – for the years 1991-1999. More recent data do not have any consistent pattern and the prices show extreme volatility and randomness.

Chart V.4 illustrates the traditional pattern of higher prices in the winter and lower prices in the summer. The three-hub average was applied to all eight hubs in the model other than Henry Hub, which has its own monthly shaping.

Chart V.4
Monthly Shaping



Electricity Demand

AURORA divides the WECC into 13 subregions with individual growth rates. Table V.3 lists the regions along with the long-run regional growth rates. The growth rates were adopted from the NPCC, "Draft Forecast of Electricity Demand of the 5th Pacific Northwest Conservation and Electric Power Plan," August 2, 2002. Short-run demand was adjusted downward to take into account the current recession, following the assumptions in the NPCC's 5th Draft of Wholesale Electric Price Forecast. Intermediate-term growth rates were increased so that the long-run growth rate was unchanged.

Table V.3 Regional Growth Rates

Region	**Annual Increase (%)**
OR / WA / No. ID	1.50
No. California	1.71
So. California	1.87
British Columbia	1.53
Idaho South	1.71
Montana	0.90
Wyoming	0.23
Colorado	1.22
New Mexico	2.43
Arizona / So. Nevada	1.39
Utah	2.32
No. Nevada	1.65
Alberta	1.53

New Northwest Resources

In 2002 there were over 8,000 MW of new resources under development. Most of the proposed projects, however, did not make it beyond the planning stage. PSE currently assumes that 2,055 MW of new natural gas-fired resources will be available in the region. Presently four plants have been completed, with two under construction to be on line by mid-2004. Table V.4 lists those plants.

Table V.4 New Natural Gas-Fired Resources

Plant	Owner/Developer	Capacity MW)	Online Date
Coyote Springs II	Avista-Mirant	260	Online
Hermiston	Calpine	530	Online
Goldendale	Calpine	248	Q2/04
Big Hanaford	TransAlta	248	Online
Frederickson I	EPCOR	249	Online
Chehalis	Tractebel	520	Q3/03

Other well-known gas-fired resources that once were expected to be developed, such as the Duke Grays Harbor plant, have not been assumed into the model. Wind resources that could be built in 2003, or later, were not assumed to be built. The AURORA database includes 473 MW of wind generation, which their developers listed as going on line in 2002.

New California and Arizona Resources

Demand from California has a significant impact on Northwest energy prices during the summer peak, hence an accurate representation of the resources serving California was included in the model. Significant resources, primarily natural gas combined-cycle and simple-cycle plants, have been completed recently in California and Arizona. The database in AURORA has been updated with information provided by Henwood Consulting, dated 4/29/03. Plants added to the database include those listed as “completed” and those “under construction,” with on-line dates in 2003. For California and Arizona together the data set includes 33 new plants of approximately 10,000 MW total capacity.

Known plant retirements were also taken into account. The California ISO published a list of plants which have been recently retired or have a retirement date reported to the California ISO. These plants total approximately 2,500 MW for California and Arizona for the period 2004-2006.

New AURORA Resources

A driver in the AURORA model is the expected return on capital invested in new generation assets for the Western Power Market. This expected return is derived through estimates of the future developer mix, the developers' respective capital structures, and their average cost of equity and debt over the forecast period.

AURORA requires an input assumption regarding who will develop future plants in the region. PSE has assumed that these plants will be developed by publicly owned utilities (Public), investor-owned utilities (IOUs), independent power producers (IPPs), or independent power producers with power purchase agreement(s) in place with an IOU (IPP/IOU). PSE's assumption for the relative contribution from each developer type is outlined in Table V.5.

Table V.5 Developer Mix

Asset Type	Public	IOUs	IPPs	IPP/IOU
CCCT	20%	30%	20%	30%
SCCT	20%	30%	20%	30%
Wind	20%	30%	20%	30%
Coal	20%	35%	10%	35%

These allocations are reasonable estimates for future developer mix and assume that in the near-term, continued weakness in the IPP credit market will require IOUs to self-build to meet load-growth demands. Additionally, as credit markets recover, financing will be easier for IPPs that have signed long-term PPAs with credit-worthy counterparties, such as IOUs. Pure merchant IPPs will still be present in the market, but their market share of new projects is expected to be far smaller than previously experienced.

The capital structure for these four developer types is identified in Table V.6. Capital structure for the IPP/IOU developer has been estimated at 70/30 debt/equity, and reflects the potential for increased leverage on projects with credit-worthy counterparties.

Table V.6 Capital Structure

Asset Type	Public	IOUs	IPPs	IPP/IOU
Debt	100%	55%	50%	70%
Equity	0%	45%	50%	30%

The cost of capital for these four developer types is identified in Table V.7. The expected returns on debt and equity for IPP/IOU developers have been estimated at 7.5 percent and 17 percent respectively, and appear valid given the returns identified for other developers. The cost of debt at 7.5 percent mirrors that of an IOU and is based on the assumption that the ultimate counterparty risk lies with the power purchaser or IOU. However, the equity return for an IPP/IOU would not be expected to match that of an IOU, since the risk profile for an IOU investor will differ from that of an IPP/IOU investor. In addition, IPP/IOU investors are likely to demand a higher rate of return to offset the greater risk associated with a highly leveraged investment.

Table V.7 Cost of Capital

Asset Type	Public	IOUs	IPPs	IPP/IOU
Debt	6.5%	7.5%	8.7%	7.5%
Equity	0%	11.5%	20%	17%

Timing and Limits of New Resource Development

In AURORA, new plants are brought online at the optimal time without regard to planning horizons. To replicate realistic planning needs, certain limits need to be placed on the rate of development on the various technologies for the 20-year analysis. Coal plants were excluded from development in the Washington/Oregon area and limited to one plant in the northern and southern California areas. Coal plants require a long development time, so they likely could come online in California in 2010 and in 2007 in other areas. Wind was restricted to one new plant per year in each region, and could be developed immediately. Natural gas-fired combined-cycle and simple-cycle turbines also have quick development times and required no limitations.

Cost of Various Technologies

The AURORA model selects new resources for addition from a set of generic resources that will result in lowest overall cost. The cost and performance characteristics were provided by Tenaska for the combined-cycle and simple-cycle gas plants, as well as the coal plant. The wind data were provided by Navigant Consulting, Inc. and confirmed by other sources, while the solar data are from the NPCC.

The capacity of most new generation resources (i.e., the capacity of individual projects in MWs) can be scaled to meet the specific needs of the developer, hence there is not one correct size or correct cost estimate for each technology. Furthermore, with shared ownership, even greater flexibility of capacity can be achieved for a utility. PSE, in collaboration with Tenaska, selected a representative plant for each gas and coal technology based both on economies of scale and on current development practices. Table V.8 provides a list of the primary characteristics.

Table V.8 Cost and Performance Characteristics

Technology	Capacity (mw)	Heat Rate (btu/kwh)	All-In Cost ($/kw)	Fixed O&M ($/kw)	Fixed Fuel ($/kw)	Variable O&M ($/mwh)
CCCT	516	6,900	710	11.00	15.55	2.00
SCCT	168	11,700	441	3.00	15.74	2.00
Coal	900	9,425	1,500	20.0	0	2.00
Wind	100	0	1,003	26.10	0	0
Solar	20	0	6,000	15.00	0	0.80

The CCCT represents a two-by-one configuration – two turbines with a heat-recovery system. These plants typically are scaled by increments of about 250 MW, with variations around those figures depending on specific configurations. The $710/KW all-in cost is based on an analysis of PSE's Frederickson site.

The SCCT represents a lower-cost traditional peak using "frame" FA or EA gas turbines in simple cycle. More expensive aero-derivative plants are available that have a better heat rate at a much higher cost. Throughout the industry and its literature, one can find a wide variety of capacities, heat rates, and costs for the numerous simple-cycle options. The least-cost option is site- and application-dependent. The costs provided by Tenaska are based on the same assumptions as the combined-cycle and coal plants, which allows for a fair comparison between the technologies. For example, the listed SCCT starts with an EPC cost (engineering, procurement and construction) of $327/kw before taking into account "soft" costs such as insurance, contingencies, and costs related to financing, start-up, spares, etc., before arriving at a total installed-capacity cost of $441/kW.

The coal plant represents a new site with a supercritical boiler design. An alternative would be a plant with 2 percent to 4 percent lower costs but with a 2 percent to 4 percent higher heat rate. Again, the least-cost option depends upon the site and application.

The wind plant is based on the assumption that 100 MW is necessary to achieve economies of scale.

Improved Efficiency

Over time the heat rate of the various thermal plants is expected to improve. Starting with the heat rates listed above, PSE adopted the performance improvements provided by the Energy Information Administration in the "Annual Energy Outlook 2003." Through 2010, coal-plant performance improves by 0.4 percent per year, combined-cycle performance improves by 1.1 percent per year, and simple-cycle performance improves by 0.6 percent per year. After 2010, improvements are assumed to be quite small (0.2 percent) or zero in the later years.

2004 – 2005 Updates

The AURORA modeling discussed above was conducted in early July, 2003 for the August 2003 Least Cost Plan Update. As part of the Power Cost Only Rate Case filed on October 24, 2003, the power price forecasts for 2004 and 2005 were updated based on the natural gas forward market as of mid-September 2003, and are reflected in Tables V.1 and V.2.