Choosing a Strategy

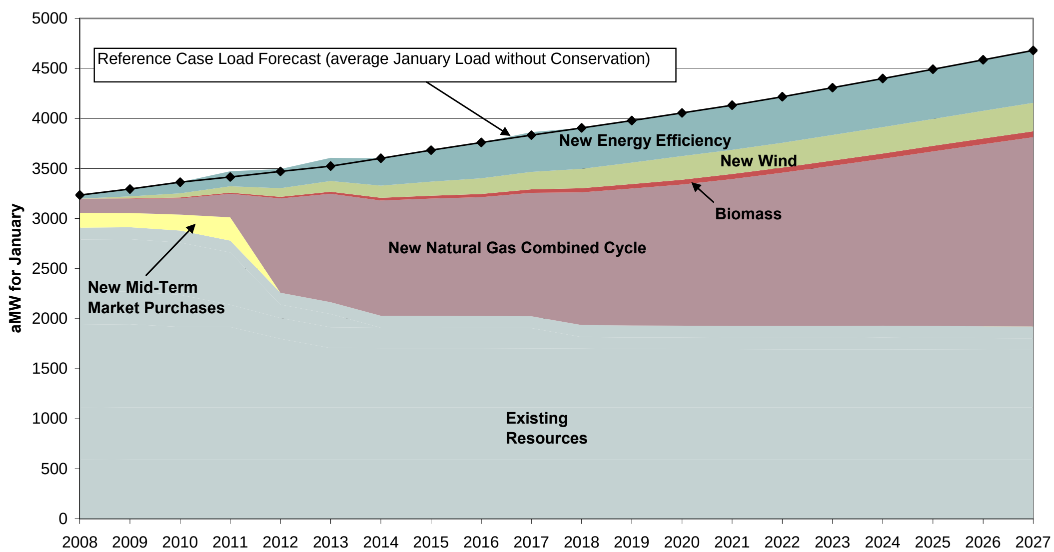
A great deal of material is described in detail in this document. Much of the information is technical and quantitative in nature, including the data, assumptions, and inputs developed, the methodology used, and many of the analytical results.
Some of it is qualitative in nature, including information about marketplace conditions, choices about possible futures to model, and assessments of the current regulatory climate.

In this chapter, we want to take a step back and look at the big picture. We want to synthesize the two types of information, and in so doing, explain the reasoning PSE used to choose the lowest reasonable cost portfolios recommended in this integrated resource plan.

I. Electric Resource Strategy

In PSE's judgment, the lowest reasonable cost electric resource strategy to pursue at this time includes aggressive investment in energy efficiency as a significant and cost-effective contribution to meeting resource need. It relies heavily on increased development of wind power to meet renewable portfolio standards. And it relies on gas-fired generation to make up the balance of energy needs that cannot reasonably be met through demand-side and renewable resources.

Figure 8-1
Preferred Electric Resource Strategy, 2007 IRP



January Energy Additions aMW—Lowest Reasonable Cost Portfolio				
	2008	**2015**	**2020**	**2027**
DSM/Energy Efficiency	36	314	432	524
Wind	0	140	235	284
Biomass	0	29	49	59
Gas CCCT	142	1172	1410	1893
PBAs	148	0	0	0

January Capacity Additions MW				
	2008	**2015**	**2020**	**2027**
DSM/Energy Efficiency	36	314	432	524
Wind	0	550	921	1,112
Biomass	0	34	57	69
Gas CCCT	149	1,234	1,484	1,992
Duct Firing	20	167	200	269
SCCT	0	0	175	441
PBAs	148	0	0	0

A. Framing the Analysis

To arrive at this strategy, PSE assessed need over the next 20 years. We constructed scenarios that represented different possible ways the future might develop. We created hypothetical portfolios containing different combinations of resources to meet that need. Finally, we evaluated the portfolios within the context of the different scenarios to find out how they behaved with regard to cost and risk. The assumptions, inputs, and data used to construct these components, and the methodology used to analyze them are explained in the body of this report.

Six scenarios were constructed for the electric analysis; all included greenhouse gas emissions costs, as we believe these to be likely by 2009. Figure 8-2 summarizes the highlights of the different scenarios. These scenarios made it possible for us to investigate significant "what if" questions about the future.

- *Current Trends*. What if current economic, marketplace and regulatory trends continue into the future?

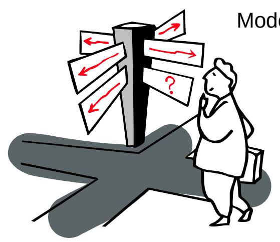
- *Green World*. How would higher-than-currently-expected charges for greenhouse gas emissions affect portfolio performance?
- *Low Growth*. What if projected economic growth in the region does not meet expectations?
- *Robust Growth*. What if economic growth exceeds current expectations?
- *Technology Improvement*. What if technological advances improve both heat rates and capital costs?
- *Escalating Costs*. What if these technological advances take place, but cost more than current optimistic projections?

Figure 8-2
Electric Scenarios

Current Trends
Moderate Gas Prices
Low Carbon Costs
Moderate Load Growth

Green World
High Gas Prices
High Carbon Costs
Moderate- Load Growth

Low Growth
Low Gas Prices
Low Carbon Costs
Low Load Growth



Robust Growth
High Gas Prices
Low Carbon Costs
High Load Growth

Escalating Costs
Current Trends +
Increasing Capital Costs

Technology Improvement
Current Trends +
Declining Capital Costs
Heat Rate Efficiency Improvement

Constructing different portfolios enabled us to compare the costs and risks associated with varying combinations of resources. All included significant emphasis on demand-side resources and sufficient renewable resources to meet RPS standards, but they differed in significant ways that allowed us to explore questions such as the following.

- How would portfolios that relied primarily on gas-fired generation compare to those that incorporated coal?
- What if coal were added sooner, rather than later?
- What was the effect of using power bridging agreements (PBAs)?
- How did increasing the amount of renewables affect results?

Altogether, we tested twelve different portfolios against the six scenarios. In the end, each portfolio's performance was ranked in each scenario, as summarized below.

Figure 8-3
Relative Rankings of 12 Portfolio-Scenario Combinations

	1	1a	2	3	3a	4	5	5a	6	7	8	9
	Aggressive Gas	**Early PBA Aggressive Gas**	**Early IGCC**	**Late IGCC**	**Early PBA Late IGCC**	**Max IGCC**	**Late IGCC w CCS**	**Early PBA Late IGCC w CCS**	**Aggressive Renew**	**More Renew w Gas**	**More Renew IGCC w CCS**	**Last IRP Portfolio**
Current Trends	4	3	5	2	1	6	8	7	12	10	11	9
Green World	4	3	11	8	7	12	2	1	9	6	5	10
Low Growth	2	1	8	4	3	10	6	5	12	7	11	9
Robust Growth	9	8	2	4	3	1	7	6	12	11	10	5
Technology Improvement	8	5	4	3	1	2	7	6	12	10	11	9
Escalating Costs	3	2	7	4	1	9	6	5	12	10	11	8

Lowest Cost Portfolio
2nd Lowest Cost Portfolio

B. Narrowing the Field: The Portfolio Screening Process

To eliminate the less favorable candidates, we applied a series of screens to the quantitative analysis. This screening process is illustrated in Figure 8-4. The quantitative analysis process and results are discussed in Chapter 5.

It is important to note that the results of the quantitative analysis are close enough that we must be cautious about drawing conclusions based solely on the numbers. While the costs are indeed close, we believe it is incumbent upon us to define the lowest cost portfolio and to provide an explanation of how we came to that conclusion.

1. *Portfolios that failed to rank 4th or higher on at least one scenario were eliminated.* Portfolios that failed to demonstrate some measure of economic advantage were considered less attractive and did not pass the screen.

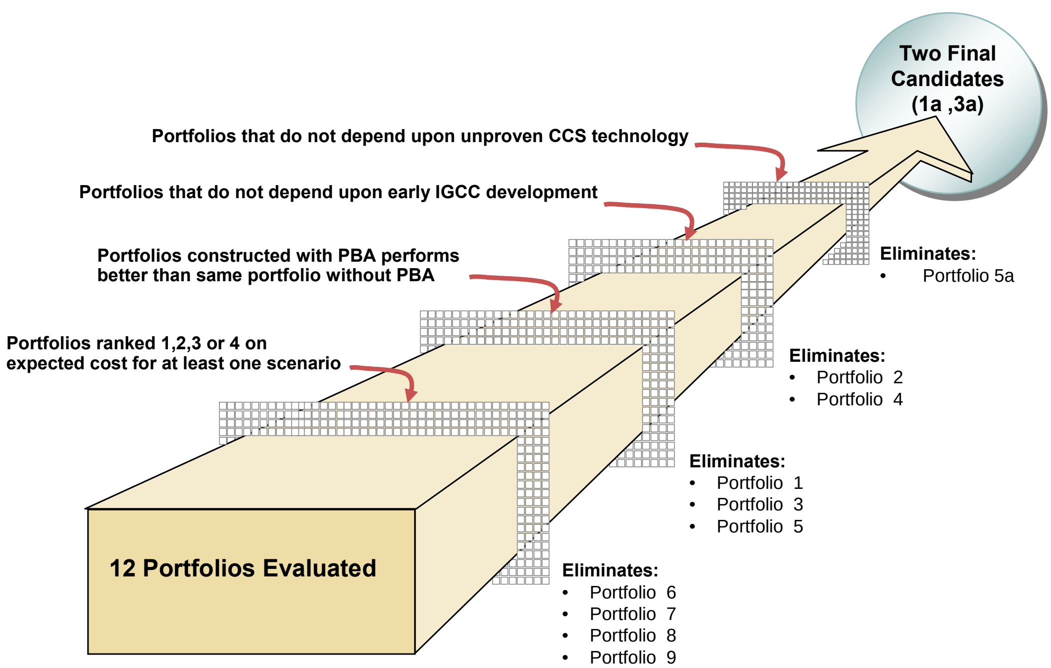
2. *Portfolios constructed without PBAs did not perform as well as the same portfolio with PBAs.* The hypothetical portfolios with and without PBAs were originally evaluated in order to normalize the comparisons between “lumpy” generation additions over the planning horizon. Under current market conditions, PBAs are

priced below the cost of new resources, which gives them an additional advantage. Portfolios without PBAs were screened out at this stage because of this advantage.

3. *Portfolios that rely on early IGCC development were eliminated.* The earliest proposed on-line date for any IGCC to appear in the region is 2014. Given the uncertainty surrounding federal regulation—and especially state legislation that may effectively prevent development of new coal resources (including IGCC)—we do not believe it is realistic to assume such plants can be brought on line so quickly. So, only portfolios featuring later stage IGCC development passed this screen.

4. *All coal projects without carbon capture and sequestration (CCS) capability were eliminated*. These projects were originally included in order to quantify the risks and trade-offs associated with CCS. At this time, it is not at all clear when—or if—CCS technology will become commercially available. Once it does, significant legal and regulatory hurdles will still need to be overcome. Portfolios that included CCS were screened out on the basis that such technology is not yet commercially available.

Figure 8-4
Electric Portfolio Screening Process



C. Final Candidate Evaluations

When the screening process was complete, two candidates remained. Both incorporated aggressive demand-side measures early in the planning horizon in order to capture the greatest benefit. Both added additional wind resources to meet RPS standards. And both relied on adding gas-fired resources to meet remaining need until late in the planning period. At 2020, they diverge in the following way.

- Portfolio 1a continues reliance on gas-fired generation to meet rising needs.
- Portfolio 3a adds contributions from coal-fired IGCC plants late in the planning horizon.

The decision presents a judgment call: If *Green World* scenario conditions emerge—with higher costs for greenhouse gas emissions—reliance on natural gas generation (Portfolio 1a) is lower cost than a portfolio including IGCC (Portfolio 3a), given that carbon sequestration is not commercially viable. Similarly, Portfolio 1a performs better in the Low Growth scenario that has a low natural gas price assumption. If the *Current Trends* scenario emerges—with relatively lower carbon costs—then the lower cost portfolio is the one that contains late IGCC (Portfolio 3a). Similarly, Portfolio 3a performs better in the Robust Growth scenario than Portfolio 1a, because of the lower relative carbon costs.

In order to explore the risks involved in this choice, we posed two further questions: What would be the cost consequences of committing to one or the other portfolio in both of the scenarios? And, how likely is it that market conditions will be more like the Green World scenario than the Current Trends scenario? We narrowed the scope to a comparison between Current Trends and Green World to focus on the specific risks that seem to drive results between additional coal and no coal—the relative difference between all-in coal costs (including carbon) and natural gas costs. This narrowing of focus is a reasonable simplification given our earlier explanation that the results of the analysis are too close to rely solely on quantitative results.

The cost of commitment. Figure 8-5 shows the comparison of cost risk across the two scenarios. If we implemented the aggressive gas portfolio (1a) in anticipation of Green World market conditions and Current Trends conditions prevailed, the net present value cost to the portfolio would be $117 million. On the other hand, if we pursued IGCC without carbon sequestration being viable and Green World conditions prevailed, the net present value cost to the portfolio would be $174 million. This told us that the scenario risk associated with coal in the form of IGCC represented in portfolio 3a was larger than the risk in the aggressive gas portfolio 1a.

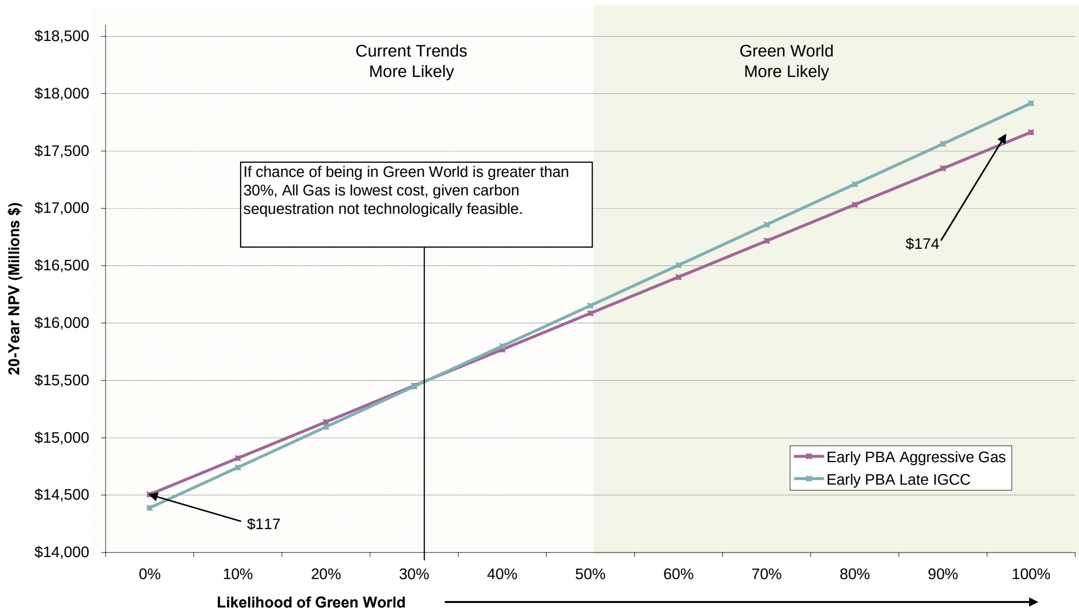
Figure 8-5
Comparison of Lowest cost portfolios across Scenarios (Millions $)

Lowest Cost Portfolios Across Different Scenarios		
	Early PBA Aggressive Gas	Early PBA Late IGCC
Current Trends	$ 14,506	$ 14,389
Green World	$ 17,664	$ 17,490

Difference From Lowest Cost		
	Early PBA Aggressive Gas	Early PBA Late IGCC
Current Trend	$ 117	$ -
Green World	$ -	$ 174

How likely is it that a Green World future will emerge? Assigning a probability to future market conditions is a very subjective exercise. However, Green World market conditions would make the difference between resource strategies relative to Current Trends. Since we do not know the likelihood of one potential future versus another, a better question is at what probability level would it make a difference? Figure 8-6 illustrates the probabilistic "tipping point" between two portfolios in the *Green World* and *Current Trends* scenarios. The end points tie to Figure 8-5: if Current Trends is the future, the cost difference between the two portfolios is $117 million NPV (net present value); if Green World is the future, the difference is $174 million NPV. The figure below illustrates the probability level at which the gas portfolio (1a) becomes lower cost than the IGCC portfolio (5a). The tipping point is 30%. Thus, if the probability of *Green World* is greater than 30%, then the heavy gas portfolio (1a) is preferred. If the probability of *Green World* is less than 30%, then reliance on the IGCC portfolio is preferred. Again, given present-day uncertainty surrounding federal and state legislation regarding greenhouse gas emissions, it seems possible that the 30% threshold may be exceeded.

Figure 8-6
Relative Risk Trade-off of Green World vs. Current Trends



D. Conclusion

In our judgment, the quantitative analysis supports a finding that portfolio 1a—which relies on aggressive investment in energy efficiency, aggressive addition of wind resources to meet renewables targets, and gas-fired generation to meet the balance of base load need—is the lowest reasonable cost resource strategy for PSE to pursue at this time. This is supported by the qualitative considerations described in the Executive Summary and by the new Washington state law precluding new coal generation without carbon sequestration.

Should CCS technology prove viable, we will reassess the trade-offs between gas and coal. PSE is actively monitoring—and will continue to monitor— activities at a number of utilities that are now looking closely at carbon sequestration. Based on our current analysis and assessment of the industry, we believe that by 2012, we may know enough to determine if CCS technology will be commercially viable by 2021. If that turns out to be true, 2012 would be the earliest we could re-examine the coal question. The primary driver for this will be the time at which CCS technology becomes commercially viable.

E. Near-term Marketplace Conditions

Although this integrated resource plan is essentially a strategic document, it is clear that several marketplace realities will confront us as we begin to acquire the resources needed to meet demand. They are worth noting here, as they will affect the tactical decisions we make as the acquisition process unfolds.

Renewables Will Require Aggressive Pursuit

Wind is currently the only renewable resource in the region capable of producing commercial-scale quantities of power. Assuming that 90% of the renewable portfolio standards established by Washington voters in 2006 will be met by wind resources, the state's utilities will need to add approximately 5000 MW of wind resources by 2027. PSE's share would be approximately 1100 MW. In practical terms, this means PSE and its development partners will need to place one wind project into commercial service approximately every 18 months beginning in 2010.

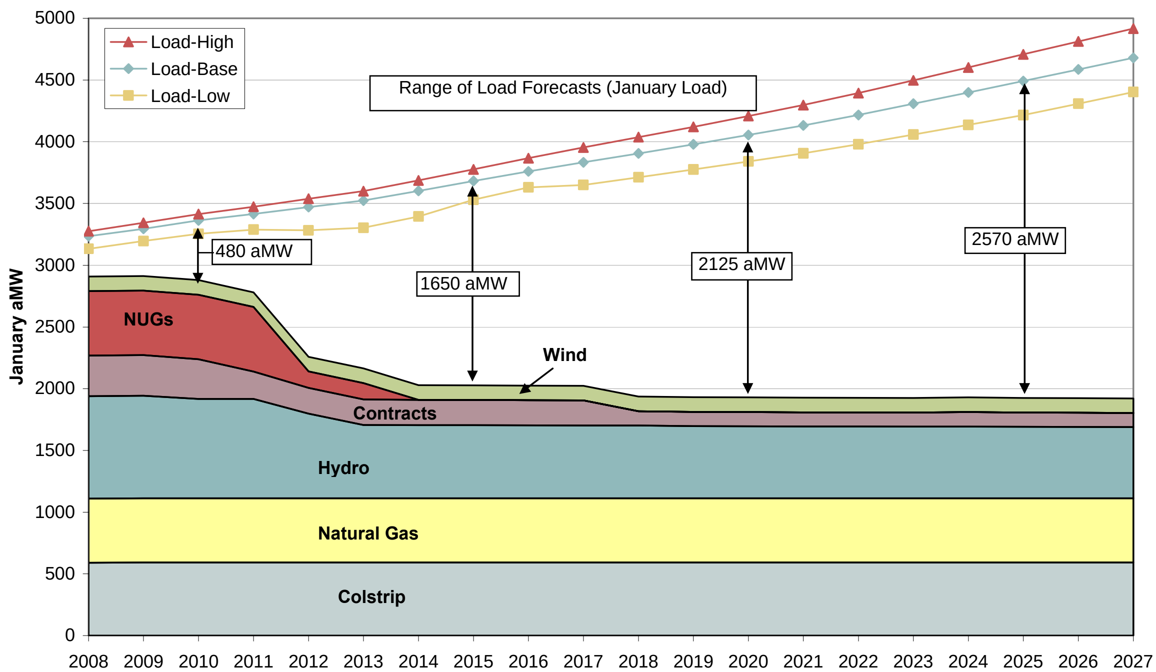
We will have to accomplish this in an extremely crowded marketplace. California recently empowered its utilities to seek renewable resources in the region; Oregon is poised to pass ambitious renewable portfolio standards; and many other western states (including Nevada, Arizona, New Mexico, and Colorado) have also established renewable standards. Demand for suitable wind sites and other renewables will be fierce in the Northwest and the West, and PSE will need to act aggressively in the marketplace to be able to meet our obligations.

All parties—utilities, developers, key vendors, transmission providers, and regulators—need to understand the size of the renewables challenge. Meeting RPS targets will require creative, coordinated efforts on a scale we have not seen before in the Northwest.

The Pace of Resource Acquisition Will Continue

PSE faces large electric resource needs in coming years due to a combination of economic growth and expiring contracts, as illustrated in Figure 8-7. We will need to acquire nearly 500 aMW of electric resources by 2010, more than 1,600 aMW by 2015, and nearly 2,600 aMW by 2025 in order to meet customer demands. This means that PSE will need to add a 150 MW wind plant, as previously mentioned, and a new 250 MW gas plant every eighteen months to two years. Thus, we see the current treadmill of resource planning, acquisition, and regulatory cost recovery continuing throughout the planning horizon.

Figure 8-7
Electric Resource Need



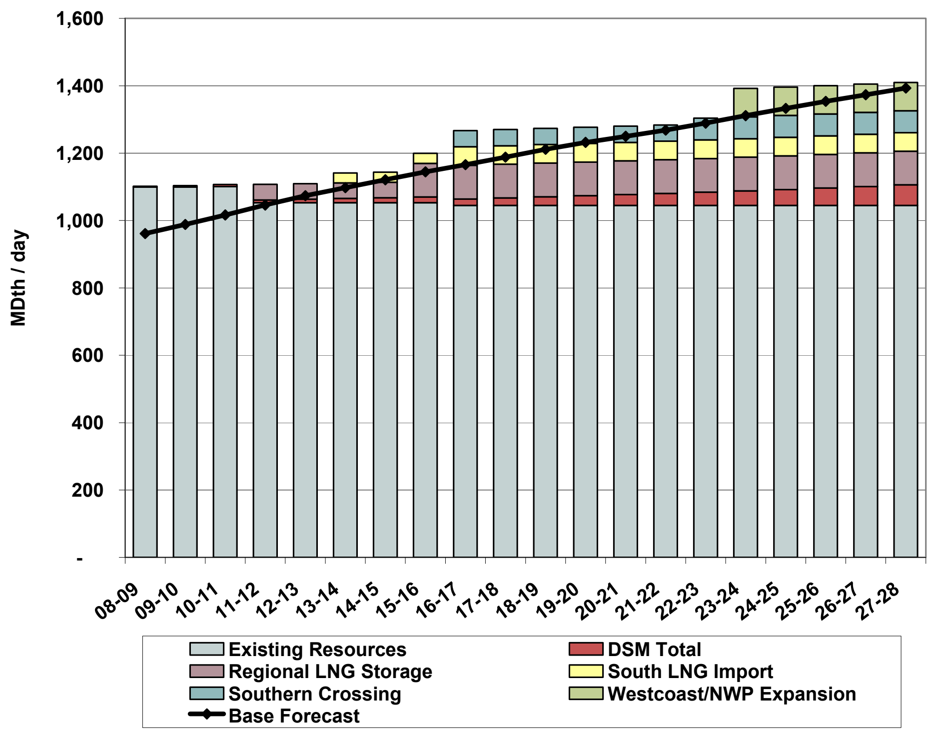
II. Gas Resource Strategy

PSE's retail natural gas resource need is growing more gradually than our electric resource need. Sufficient capacity resources are on-line and under development to meet needs through the winter of 2011-2012. We believe that the lowest reasonable cost strategy for meeting projected demand is the portfolio shown below. It includes cost-effective energy-efficiency measures as well as three supply-side alternatives that appear to be both feasible and cost-effective:

- participation in a regional LNG storage facility
- purchase of gas from a LNG import facility
- participation in an expansion of the Southern Crossing pipeline

Beyond approximately 2023 additional pipeline capacity is a feasible alternative to meet customer needs through 2027. Existing and prospective resources are both shown in Figure 8-8.

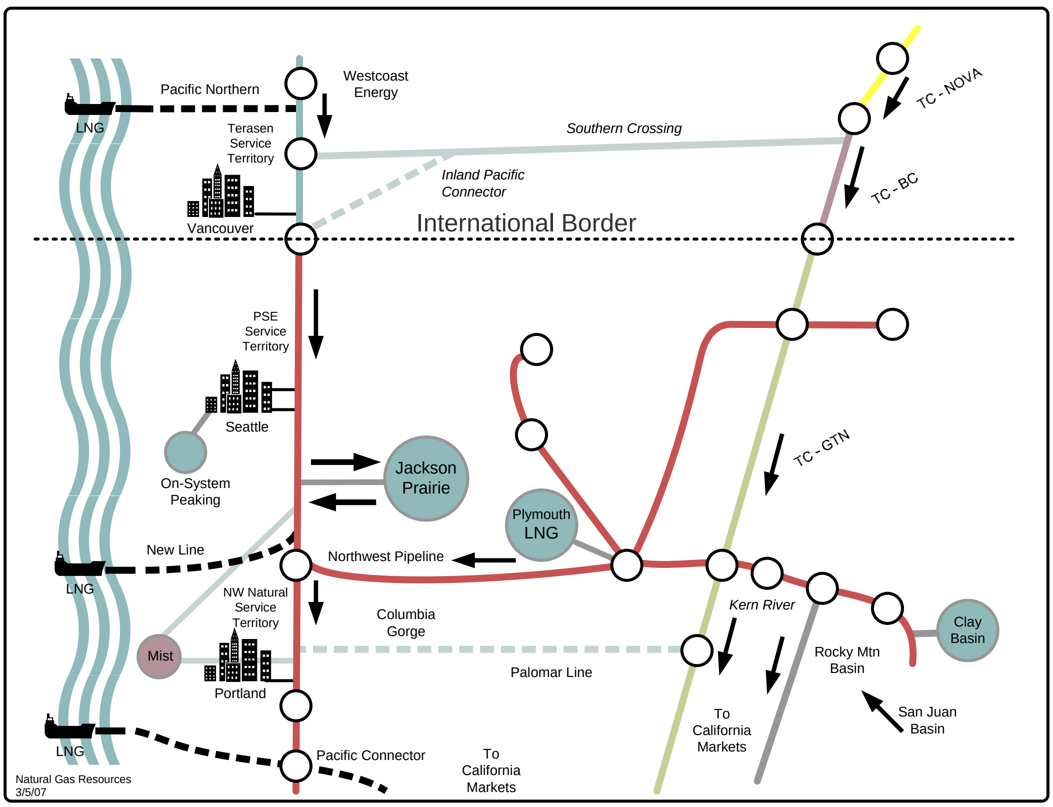
Figure 8-8
Lowest Reasonable Cost Portfolio - Gas Sales Customers



Winter Capacity Additions (MDth) - Reference Case Portfolio				
	2008	2015	2020	2027
DSM/Energy Efficiency	2	17	32	61
Regional LNG Storage	0	100	100	100
South LNG Import	0	30	55	55
Southern Crossing Pipeline	0	0	48	65
Westcoast/NWP Expansion	0	25	25	107

The location of these supply alternatives is shown on the regional gas transportation map in Figure 8-9.

Figure 8-9
Location of Gas Supply Resource Alternatives



Gas planning analysis focuses on where to buy gas, how to transport it to customers, how to best utilize storage facilities and the impacts of potential energy efficiency programs to minimize the cost of meeting customer loads. The network of supply areas and market hubs, the pipeline transportation system, storage facilities, and demand areas lends itself to analysis using linear programming models, so identifying the lowest reasonable cost portfolio for retail gas resources is somewhat more straightforward than electric analysis.

We began by developing demand forecasts and comparing these with existing resources to identify need. We created a set of assumptions regarding resource costs and gas prices (these are explained in Chapter 6, Gas Resources). Then we developed alternatives to address our primary needs: pipeline capacity, storage, energy efficiency, and supplies. Once these elements were in place, we were able to use a linear programming model to identify the portfolio that would minimize costs over the planning horizon.

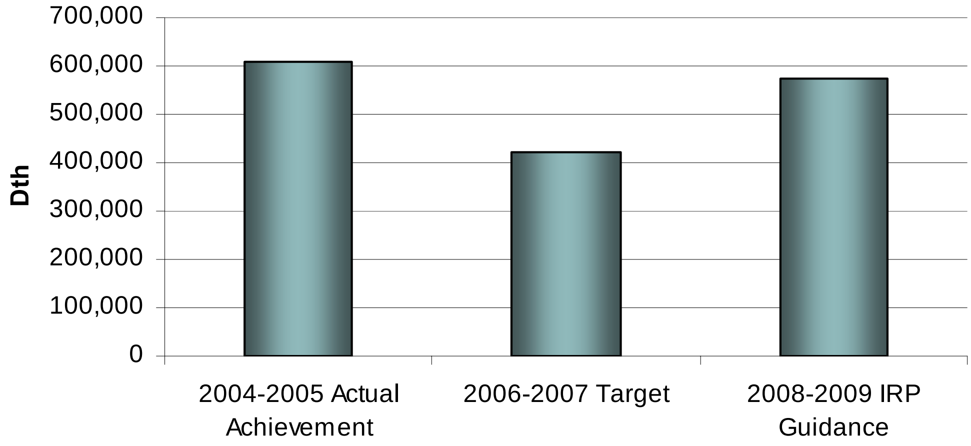
Four scenarios were also developed in order to investigate the effect different possible futures might have on gas prices and demand. The Base Case assumed present trends continue and gas prices stay in the middle of the range. A Green World scenario assumed higher prices due to increased demand for natural gas. Robust Growth assumed high customer growth rates and therefore higher demand and prices. Low Growth assumed lower growth and prices. Monte Carlo analysis enabled us to test how sensitive optimal resource additions were to these assumptions about price and demand.

Gas Resource Additions

Demand-Side Resources

Figure 8-10 compares our previous energy efficiency accomplishments, our current target, and our new level of guidance based on the results of this analysis. In the short term, this IRP guidance includes 576,000 Dth of energy efficiency savings for the 2008-2009 period. This is an increase of 37% over current 2006 – 2007 targets. It is slightly less than the savings achieved in 2004 – 2005, which included large savings from the unique, one-time commercial spray heads project.

Figure 8-10
Short-term Comparison of Gas Energy Efficiency



Supply-Side Resources

Direct-connect pipelines move gas from upstream sources to PSE's local distribution system. At this time, there are no practical alternatives to our current supplier, Northwest Pipeline (NWP). Future expansions of NWP, even though incrementally priced, will be our most cost-effective alternative for the present.

To address further storage and peaking needs, participation in a regional LNG storage facility was found to be the lowest reasonable cost alternative. In general, we have sufficient pipeline capacity to deliver total annual requirements; we require additional capacity mainly at peak usage times. Further expansion of the Jackson Prairie storage facility is not economically practical. Investing in development of a regional storage facility that is able to utilize low-cost redelivery service is a relatively less expensive solution than acquiring firm year-around pipeline capacity to meet peak day loads.

For gas supply needs, a South LNG import terminal located in southern Oregon was selected in all scenarios as a cost-effective way to increase peak supply capacity as well as to diversify sources of supply. In conjunction, development of some limited transportation capacity from the Jordan Cove site to PSE's city gate also appears economically feasible. Ultimately, the attractiveness of this alternative will be determined in large part by the final terms and conditions of any gas supply agreement arranged in association with it. The other LNG import facility evaluated in the analyses is the proposed Kitimat facility located on the north B.C. coast. The optimal portfolio also contains additional gas supplies from various supply basins or trading locations.

The upstream pipeline capacity alternative recommended in this portfolio required a judgment call on PSE's part. Going strictly by the numbers, the analysis recommended that the lowest cost alternative was limited expansion of the Westcoast Pipeline capacity, which would increase our capacity to transport gas purchased at Sumas and Station 2. However, we have some serious concerns about increasing our reliance on those markets. Sumas is already the source of 50% of PSE's gas supplies, and in recent years producers and marketers have shown a marked preference for moving their activities to the AECO hub. Because of AECO's access to Chicago and other Midwestern markets (in addition to California and the Northwest), its market is more liquid and its prices less volatile than Sumas.

Although the Southern Crossing/Inland Pacific Connector alternative recommended here has a relatively higher cost, it offers the significant advantage of enabling PSE to diversify our supply sources by decreasing our dependence on Sumas and northern B.C. gas supplies, and increasing our access to the more liquid AECO hub.

Figure 8-11 shows the decision path and timing necessary to acquire resources for the projected capacity need in 2012-13.

Figure 8-11
Natural Gas Sales Decision Path