Portland General Electric Co.

DELIVERING NEW CHOICES FOR PGE'S CUSTOMERS

Proposed Action Plan, Integrated Resource Plan

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Introduction

By filing this Proposed Action Plan, PGE takes the second and final step in requesting acknowledgement of our *2002 Integrated Resource Plan (IRP)*, which we filed in August of that year, and updated in our *Supplement*, filed in February 2003.

In our *Supplement*, we indicated that we would issue a request for proposals (RFP) for energy and capacity and use the results to help identify the specific resource actions we prefer to meet our resource targets. We asked that the Commission acknowledge our *IRP* in two steps. First, we requested acknowledgement of our "Updated Action Plan," which the Commission granted in Order 03-461, dated August 1, 2003.

Next, we proposed to further update our Updated Action Plan based on the results of the RFP, further development of the Port Westward site, and informal work in the marketplace. The results of these updates are incorporated in the Proposed Action Plan described in this document.

Topics covered in this chapter include:

- Context for PGE's Draft Action Plan
- PGE's Goals
- Resource Planning and Ratemaking
- Acknowledgement Process
- Communicating Resource Planning Updates
- Organization of this Document

Context for PGE's Proposed Action Plan

The integrated resource planning process in which Portland General Electric is presenting this Proposed Action Plan is probably one of the longest running such processes since Oregon began resource planning in the late 1980s. We began the current planning effort in Fall 2000, with a "Resource Plan," required by OAR 860-38-0080, suggesting a disposition of our resources to enable direct access. Events soon began to overtake this initial plan, including those listed below:

- Rolling blackouts in California in the winter of 2000-01.
- Record high prices for all tenor of purchased power, from hour-ahead to future multiple-year term deals in the winter and spring of 2001.
- Oregon HB 3633, enacted in 2001, which changed the premise of the state's restructuring by requiring that utilities offer all customers a "cost of service rate" until such time as the Commission made certain findings, which could not occur before summer 2003, and delayed the start of direct access to March 2002.
- Federally-imposed Western Electricity Coordinating Council (WECC)-wide price caps in June 2001.
- PGE's single largest price increase took effect on October 1, 2001. However, the overall percentage increase in our residential rates since 1980 has almost exactly

matched that of the consumer price index, meaning that, in 2003, real residential rates are almost identical to those of 1980.

- The dramatic drop in wholesale gas and electricity prices in Fall 2001.
- Load loss across the Northwest and in California, caused primarily by unusually poor economic conditions and aided by significant energy price increases.
- Struggles of retail providers of natural gas and electricity with the wholesale price increases of the previous 12 months.
- Some acceptance by PGE customers of market-based price options in 2002 and 2003. Accounts totaling 32 MWa have applied for the shopping credit, and are enrolling with Electricity Service Suppliers (ESSs) for 2004.
- Weak – about 10 MWa – customer response to the opportunity to de-link from PGE's resources for at least five years.
- A retreat from direct access programs in California, Nevada, Arizona, and New Mexico; no movement toward direct access in Idaho or Washington, although Washington has a limited program in place for a handful of Puget Sound Energy customers.
- A severe contraction in the number of natural gas and electricity marketers, with many firms closing their trading floors altogether and a consequent constriction in the liquidity of gas and particularly electric markets.
- The initiation in California, Arizona, Nevada, Idaho, Washington, and Utah of new traditional rate-based utility generation.

These events make resource planning a challenge. It is unclear whether public policy in the West will settle on a gradual movement to full electric wholesale and retail competition, or embrace a model of vertical integration in which short-term purchases and sales play only a balancing role.

Meanwhile, the current physical electric system is dynamic. In the Northwest, we have a relatively young thermal system. Because of the pace of development and early reliance on hydro resources, our fleet of thermal generation dates largely from the 1970s and 1980s. We will not begin to retire these plants for another 20 years, which provides us with little comfort now. Those years will pass all too quickly and, without adequate planning, may subject the region to a building program on the scale of the 1970s. Finally, few expect declining loads in the Northwest to be a permanent condition.

Over the next few years, the region must begin making resource decisions, whether or not public policy is clear. PGE's situation is even more urgent. For economic reasons, we retired Trojan, one of our largest thermal resources, in 1993. As a result, in this Plan we have a resource gap as we start the process of meeting load growth and acquiring resources to replace those that will retire. We must choose the best resource mix for the near and not-so-near future, and it is in this context that we present our Proposed Action Plan.

PGE's Goals

We prepared the Proposed Action Plan with three goals in mind and urge the Commission to consider them in evaluating our Plan. The Plan should have a good chance of moving us closer to the results we want to achieve. The individual actions are not ends in and of themselves, but are means to an end, which should be the nature of electric service that Oregon's business and residential customers want.

The three goals that guide us are:

- Providing our customers a reliable supply of electricity.
- Achieving relatively stable and predictable electric prices over time.
- Acquiring cost effective resources using processes and analyses consistent with the principles of least-cost planning.

These goals are consistent with the least-cost principles articulated in Commission Order 89-507 and are appropriate given the events that have transpired over the past few years. Each goal deserves further explanation.

Reliability has several facets. One is physical: Is power available for delivery and can PGE deliver it over our physical system under all circumstances except extreme acts of nature? Another, and perhaps more important, perspective on reliability is from our customers, and is so deeply embedded in their perspective, and ours, that we often overlook it: "Is this power available for delivery and delivered when I want it in the amounts I want without my having to provide notice or commitment to my utility regarding my consumption?"

This fundamental view of reliability is the powerful value proposition that underlies virtually all electric service in the United States today. Other countries provide electricity under physical demand limitations. Some provide electricity when and if they can, with no notice to customers. We built this industry to provide electricity all of the time, charging individual customers according to what they actually use and requiring no reservations. This is electricity as an infrastructure service that is a right, rather than as a commodity. While individual customers may view electricity, and evaluate reliability, within the latter context, only government can enforce a widespread change in public and customer expectation.

Our goal of reliability relies on the current value proposition of electricity as infrastructure that is a right. Moreover, we include in the concept of reliability the even higher needs for physical reliability that some of our business customers require because of the sensitivity of their manufacturing processes or critical information services. For some customers, such as Intel, it is no longer a matter of whether electricity is available in a given day or hour but whether we provide exactly the right amount of electricity every fraction of a second. Because these customers play such a critical role in our service territory's economy, we consider it vital that we plan to meet their reliability needs.

Stability and predictability of price also have several facets and span near- and mid-term periods. We can efficiently convey these concepts by listing the questions our customers, and their representatives, should be able to answer if we have achieved price stability and predictability:

- What is the long-term price trend for electricity service?
- What are the primary factors behind near-term changes and those that will drive the long-term trend?
- When will my prices change, and will I have ample notice?
- Will each individual price change be small and proportionate to the long-term change?

Stability and predictability provide a good environment for personal and business investment. This goal also fosters confidence and trust in those responsible for providing and overseeing the provision of electricity because it enables and requires strong communication and effort to reach understanding.

Our goal of acquiring *"least cost" resources* recognizes the forward-looking nature of decision-making. We view least-cost planning as primarily an analytical and public process that precedes major resource decisions, which may include adding or retiring resources. As defined by the Commission in 1989, least-cost planning is a systematic assessment of the options, including demand-side options, the risks of each, and the uncertainties in the environment. "Least cost" from the customer perspective frees us all to look at more than just rates and to consider that demand-side measures could lower bills, even while raising rates, and produce a lower overall cost than supply-side actions alone.

We do not view least cost as a on-going measure of success, because this would require the impossible task of constructing the right comparison. Is the comparison daily index prices? Is it a different portfolio of mid- and long-term resources? Understanding the effects of different choices can improve the quality of forward-looking analyses, but the only relevant decisions are those not yet made.

When the Commission first adopted least-cost planning, the goals of the resulting electric service were implicit. The lack of perceived choices made explicit statement of the desired end state unnecessary, but that is no longer the case. Our goals of achieving reliable supply at relatively stable and predictable prices, using the principles of least-cost planning to acquire cost-effective resources, comprise our explicit answer to the question: Least-cost provision of *what kind* of electric service? The Commission and our stakeholders may have other goals in mind that supplement or contradict these goals. We urge that the desired end state be a part of any discussion and resolution on our Final Action Plan. While circumstances outside of anyone's control may interfere with, or even prevent, reaching a desired end state, it is certain that we will never reach such a state if we are not clear about what it is.

Resource Planning and Ratemaking

With our *Supplement* in February 2003, we raised for the first time the ratemaking implications of resource planning. This discussion is necessary to achieve a customer view of the results of resource choices. Customers pay bills derived from consumption and the rates utilities charge. Rates are a direct result of ratemaking policies and methods. The goal of stability and predictability, in particular, is unreachable unless ratemaking policy is on the table along with resource choices.

We explained last February that certain resource and ratemaking combinations could adversely affect our ability to absorb risk and, thus, our ability to provide price stability. Some combinations could also raise our cost of capital. These results are avoidable with changes to ratemaking, but we did not want the decision on resources made without due recognition of the need for such changes.

This Proposed Action Plan requires only evolutionary, incremental ratemaking changes, not sweeping revisions to current policy and methodology. Our assumptions regarding ratemaking for this Plan are listed below:

- PGE will continue to forecast net variable power costs annually, updating fuel and purchased power, and seek a permanent method for improving ratemaking for hydro-electric resources.
- We will prepare resource rate plans for the mid- and long-term contracts that propose alternatives for compensation to PGE for those risks that the Commission would like us to manage on behalf of customers.
- If we develop Port Westward, the Commission will allow inclusion of its prudent costs in rate base, and set rates for the plant on a cost, rather than a market, basis. We will evaluate a resource rate plan for Port Westward.

Acknowledgement Process

PGE proposes to work with OPUC Staff and IRP participants to enable the Commission to reach a decision on acknowledgement in early 2004.

Table 1. Proposed Acknowledgement Schedule

January 14, 2004	PGE files Proposed Action Plan..
Mid-January	Independent Observer files interim report on RFP process to date in UM 1080, confirming that scoring criteria do not inappropriately bias scoring in favor of an equity resource and that the scoring was done fairly and without bias.
Week of January 26	Public workshop on PGE's Proposed Action Plan.
Early February	PGE provides informal status report on RFP negotiations to OPUC.
February 13	Parties file comments on Proposed Action Plan.
March 5	PGE files: ▪ Response to comments. ▪ Final Action Plan. ▪ Motion to Amend the Schedule in LC 33and Request for Waiver of OAR 860-038-0080.
March 19	Staff issues draft order and recommendation.
April 6	Commission meeting to acknowledge Final Action Plan.
TBD	RFP negotiations complete.
TBD	Independent Observer files final report on RFP process as required by Order 03-387, PGE submits summary report of bidding outcome as required by Order 91-1383. Both reports submitted in UM 1080
TBD	PGE files specific resource actions for rate treatment.

The schedule contemplates that we may change the Proposed Action Plan based on comments received from Staff and participants. Thus, we will file a Final Action Plan after the initial stages of review.

Communicating Resource Planning Updates

During 2004 and 2005, we intend to provide OPUC Staff, participants and the Commission, if it so desires, updates on our progress in implementing the Action Plan. Updates would include short-term market conditions, status of our short-term energy and capacity acquisitions, and our ongoing strategy for such acquisitions. We hope to offer these updates at our proposed Quarterly Power Supply Update meetings, and in other forums as appropriate and convenient for participants.

Organization of this Document

The balance of this document leads off with our proposed resource actions, followed by several chapters in which we discuss, in greater detail, the circumstances, processes and analyses that have led to our proposal. The chapters include:

- PGE's Proposed Action Plan.
- PGE's Energy and Capacity Needs.
- Update of Building Blocks and Signposts.
- Update of Our Load Resource Balance.
- Requests for Proposals – Energy, Capacity, Gas
- Update on Port Westward.
- Natural Gas Outlook and Strategy.
- Portfolio Analysis.
- Technical Appendices.

PGE’s Proposed Action Plan

PGE proposes to take the resource actions described in this chapter and operate under this general resource acquisition strategy during 2004 and 2005. We will complete most of the implementation in 2006 and 2007. In 2005, we will file an integrated resource plan to develop additional resource actions to be initiated in 2006 and 2007, and at that time will also update our long-term strategy as needed. Topics covered include:

- Energy and Capacity Targets
- Energy and Capacity Resource Actions
- Transmission Actions
- Natural Gas Actions
- What Planning Assumptions Did PGE Apply to Meet Our Goals?
- Balancing the Goals
- Applying These Considerations to the Action Plan
- Conclusion

Energy and Capacity Targets

We have identified a gap between PGE’s current resources and the electric service we will supply our customers during 2007. Table 2, below, shows the gap between the amount of energy our customers will use, on average, during 2007 and the amount of energy our current resources provide. It also shows the gap between the amount of capacity our current resources provide and the amount of capacity our customers require during a peak hour that occurs, on average, once every two years. Our capacity gap includes operating reserves of six percent, about 235 MW, and planning reserves of about 235 MW. Our customers’ energy and capacity needs are described in greater detail later in this chapter, and also in “Update of Our Load-Resource Balance,” below.

The *targets* indicate the duration of resources we intend to acquire to fill the gaps. For purposes of energy, mid- and long-term refers to resources of at least five years’ duration. For capacity, the mid- to long-term refers to resources of at least two years’ duration. We propose to acquire up to 635 MWa of energy, and about 610 MW more of capacity, from mid- to long-term resources, *after accounting for the capacity value that filling the energy target will bring*.

Table 2. 2007 Gaps and Targets

	Energy (MWa)	*Capacity (MW)*
Gap	760	1,890
Capacity value, filling energy target	-	(905)
Short-term energy target	(125)	-
Short-term capacity target	-	(500)
Total mid- and long-term target:	635	485

Energy and Capacity Resource Actions

We request that the Commission acknowledge our plans to complete the following energy resource actions.

Existing Resources

- *Complete upgrades to our Beaver and Boardman plants, and runner upgrades at Round Butte,* gaining 46 MWa of energy, and 15 MW of capacity incremental to energy, in 2004. Plant upgrades provide increased energy, capacity and reliability. The Round Butte and Beaver work is already completed.
- *Renew our contract with the Confederated Tribes of the Warm Springs Reservation* for the output of their share of the Pelton-Round Butte hydro projects and the Pelton re-regulating dam, adding 63 MWa of energy and 102 MW of capacity incremental to energy from January 2007 through February 2012. Twenty-five MWa of this extension is during on-peak hours at fixed prices, contributing to rate stability. We have completed this action.
- *Extend Bull Run through 2007, adding 12 MWa in 2006, and 6 MWa in 2007.* This two-year extension augments our hydrogeneration resources, which have no fuel costs.

New Mid- to Long-Term Resources

- *Build one unit of Port Westward as a rate-based resource*, using G-class turbine technology, producing about 350 MWa beginning in October 2006, if appropriate bids for the power island are received and, otherwise, proceed using F-class technology. This choice takes advantage of improvements in technology, yielding lower expected power costs as a result of lower heat rates and lower capital costs per installed kilowatt.
- *Acquire up to 65 MWa (195 MW) of wind generation*, provided we can obtain the necessary transmission and integration services, and that Energy Trust of Oregon (ETO) funds permit a price within the range of other alternatives. This target exceeds that set in our IRP – it provides fuel diversity and makes use of the ETO funding mechanism.
- *Acquire up to 150 MWa in fixed price power purchase agreements*, for durations of five to 10 years. These fixed-price PPAs will contribute to rate stability and enhance diversity in the length of resource terms.

- *Acquire up to 150 MWa of tolling for baseload energy, and up to 400 MW of tolling capability for peak purposes*. Arranging for the potential use of these mid-term resources also enhances the length-of-term diversity of our portfolio.
- *Acquire 25 to 50 MW of duct firing capability at Port Westward* for reliability and economic dispatch. Because it provides a medium heat-rate at a low capital cost, duct firing is a cost-effective year-round "reserve" resource.
- *Acquire up to 100 MW in seasonal exchange contracts*. Seasonal exchanges can help our resources to better match our customers' load shape over the year.
- *Pursue dispatchable standby generation of up to 30 MW for peak purposes*, providing cost-effective peaking capability.
- *Acquire capacity through customer demand reduction programs* when cost-effective, potentially including residential water heat load control, large customer customized reductions and real-time pricing. We will continue to take demand-side actions as technologies and mechanisms evolve.

Ongoing Short-Term Resources

- *Acquire energy to meet up to 125 MWa of our average annual energy need*, to cover customers that prefer service on indexed rates or short-term arrangements with an ESS.
- *Buy and sell to balance our energy position to meet daily, weekly and monthly energy requirements* in the forward standard and structured markets. We will continue to use effective methods for meeting our customers' requirements, which vary by day, week and month.

Tables 3 and 4 summarize our proposed resource actions. We will select from among these choices, based on post-RFP negotiations, to reach the target described earlier in this chapter.

Table 3. Incremental Energy Resource Mix, 2007

Energy Resource	*Energy (MWa)*	*Notes*
Plant upgrades	46	Beaver, Boardman.
Confederated Tribes contract renewal	63	Pelton-Round Butte hydro project.
Bull Run extension	6	12 MWa in 2006, 0 MWa in 2008.
Port Westward baseload	240 or 350	One unit, F or G technology respectively, no duct firing, at 93%.
Wind	Up to 65	Limited by transmission, ETO funds.
Fixed Price PPAs	Up to 150	-
Gas tolling	Up to 150	-
Short-term acquisitions	125	-

The capacity actions shown below are *in addition* to the capacity added by filling our energy actions.

Table 4. Incremental Capacity Resource Mix, Winter 2006-07

Capacity Resource	*Capacity (MW)*	*Notes*
Plant upgrades	15	Incremental to energy.
Confederated Tribes contract renewal	102	Incremental to energy.
Port Westward duct firing	25 to 50	Depending on technology choice and economics.
Dispatchable standby generation	Up to 30	At 10 MW/yr.
Peak tolling	Up to 400	
Seasonal exchange	Up to 100	
Low heat-rate tolling.	-	Acquire as cost-effective.

We also plan to take the following actions, carried forward from the original action plan found in our *2002 IRP*:

- *Residential Time of Use.* A tariffed, voluntary program producing non-dispatchable capacity.
- *Large Customer Real-Time Pricing.* Tariffed as an experimental pilot that we may include as a capacity resource in future resource plans.
- *Large Customer Capacity Reductions.* The response received through our 2003 Request for Information was limited, and reductions are voluntary (See "Requests for Proposals – Energy, Capacity, Gas," below, for further discussion.
- *Monitor public policy and cost information on renewable resources.* Understand and anticipate customer demand and legislative requirements for renewable resources to position PGE to acquire more renewable resources if desired or required. Update our estimates of the rate effects of additional renewable resources.
- *Monitor signposts* identified here, and in the *IRP* and *Supplement,* for significant changes, and respond accordingly.

In our *IRP* (p. 108) we listed residential direct load control pilot programs for space and water heating. The results show that neither currently is an economic capacity resource.

Transmission Actions

- *Continue to participate in discussions* focused on creating the conditions for additional transmission infrastructure investment and increased efficiency in transmission operations.

- *Negotiate aggressively with the Bonneville Power Administration (BPA)* to support wind development with viable transmission arrangements.
- *Construct a new transmission line from Port Westward to Trojan* if we build the new plant.
- *Participate in funding BPA upgrades* as appropriate.

Natural Gas Actions

Should we proceed in developing a new plant at our Port Westward site, we propose to take the following actions to fuel the facility:

- Acquire up to 69,000 Dth per day of firm gas transportation to ensure reliable gas delivery.
- Acquire market gas storage capacity to assist in managing gas price volatility.
- Extend the tenor of our gas purchases and layer these purchases into the portfolio.

What Planning Assumptions Did PGE Apply to Meet Our Goals?

In the "Introduction," above, we explain the three goals that guide us:

- Providing our customers a reliable supply of electricity.
- Achieving relatively stable and predictable electric prices over time.
- Acquiring cost-effective resources using processes and analyses consistent with the principles of least-cost planning.

We developed specific sets of criteria for evaluating reliability, stability and predictability of prices, and least cost.

Assuring Reliability of Power Supply

While we strive for stable rates at reasonable levels, we first must obtain reliable supplies. We considered adequacy and reliability of supply, and adequacy of reserves, in evaluating the reliability of our power supply.

- *Adequacy of supply relative to our customer demand*. Our planning guideline is to balance, annually and on average, our energy supply and demand, while accounting for the variance of demand on a month-by-month basis. We also assume a capacity planning standard that requires meeting the largest amount of electricity our customers may demand based on conditions that occur, on average, once every two years.
- *Reliability of supply*. We chose proven technologies that have high availability factors, adequate fuel supplies, and reliable transmission paths. We continue to monitor emerging technologies, and will consider them in future resource plans if they prove to be at least as reliable and cost-effective as those we currently employ.
- *Adequacy of reserves*. A key element of a reliable supply of electricity is an appropriate and economic level of reserves to use in the event of losing generating capacity To this end, PGE is a member of the Northwest Power

Pool Contingency Reserve Sharing Operating Agreement. This agreement requires that control area operators carry contingency reserves against their generation and provides for a reciprocal right that allows members to call upon the reserve capacity of other members in the event of a disruption in generation for a maximum of 60 minutes. Beyond this time period, the member requesting reserve capacity is responsible for remedying its own loss of generation. For longer-term outages, such as extended plant outages, degraded hydro conditions, non-delivery of contract resources, or loss of transmission capability, we must consider planning reserves as we manage the risks of finding adequate supplies in the market. We also must compare market costs with those of holding capacity and energy reserves, or self-insuring as events occur.

Contributing to Stable and Predictable Prices

In acquiring or developing new resources, we considered factors that specifically affect the stability and predictability of power supply prices. We heard clearly from our customers that reasonable prices for electric energy supply, and the year-to-year stability of these prices, are important. We identified several risks that we must manage to achieve stable pricing: electric and natural gas price volatility, the availability of electric transmission and natural gas transportation, hydro conditions, extreme weather conditions, plant performance, credit risk, environmental legislation and regulations, and transmission congestion costs.

Indicators of "Least Cost"

While customers want stable and predictable prices, they also want them to be as low as possible. We considered two factors related to acquiring resources at least cost. First, "least cost" does not mean *lowest* absolute *cost*. Oregon's least-cost planning rules require that resources be acquired at least cost, considering variability of costs, consistent with the long-run public interest. The Commission explained in Order 89-507, "[t]he result of the process is the selection of that mix of options which yields, for society over the long run, the best combination of expected cost and variance of costs." (Order 89-507, p. 2).

We also evaluated costs on more than just a resource-by-resource basis. We examined the total cost of various portfolios consisting of our existing resources plus new resources, and also the expected variability of costs over a range of assumptions for key variables that introduce volatility and associated risk.

Balancing the Goals

It would be relatively easy to choose resources in a way that would meet only one individual goal, but it is much more difficult to optimize resource choices to meet all the goals. The choice of energy resources to meet a set of sometimes conflicting goals is analogous to selecting investments in a portfolio to balance the overall objectives such as total return, variance of return and risk of loss. The key is to strike a balance among our resource choices such that we can meet our overall goals and minimize the risks associated with these choices.

In trying to strike this balance, we selected resources that achieve reliability, can support price stability and predictability, in some cases with additional actions, and that, based on the best information and analysis today, will likely have lower lifetime costs than other choices.

Selecting for Reliability of Supply

In considering reliability, the company's self-build option, Port Westward, stands out. The plant design uses proven gas-fired combined-cycle combustion turbine (CCCT) technology and an existing company site with supporting infrastructure, and the plant would connect directly to the company's transmission system.

To identify other resources, we also conducted an RFP for energy and capacity products, and in response received more than 100 proposals for energy and capacity supply from over 40 bidders. In evaluating the bids, we used criteria that favored proven technology, experienced developers and operators, adequate infrastructure, credit-worthiness, secure fuel supply, and adequate transmission. We provide more information about the RFP response under "Requests for Proposals – Energy, Capacity, Gas," below.

We chose an amount of capacity to meet an operating reserve margin of six percent to meet WECC-imposed operating requirements, a figure dictated by physics and prudent engineering practice. To this operating reserve we add a planning reserve margin of an additional six percent as a contingency against extended plant outages, extended transmission outages and extremely high demand due to extreme weather conditions.

Helping to Ensure Relatively Stable and Predictable Prices

Recognizing that one resource type or technology would expose us to numerous risks that create price volatility, we chose a portfolio of resources that depend on different fuels, technologies, systems, and contract durations to create diversity to mitigate concentrations of risk. We evaluated these resource choices, together with our current resources, grouped as portfolios against futures exhibiting stochastic variability in electric and gas prices, and hydro conditions.

Choosing Resources to Achieve Least Cost

We chose resources from our RFP bids that had the best overall score, 60 percent of which was comprised of pricing. We applied this same scoring criteria and methodology to Port Westward, with the result that this self-build option scored among the best alternatives rated for price. Then we evaluated our trial portfolios and identified those resources that provided the lowest net present value of costs, *i.e.*, the least cost, and the lowest variance of prices. We also worked toward the "long-term public interest" by selecting a portion of renewable resource to meet our resource needs.

Other Considerations in Selecting a Resource Portfolio

After evaluating each potential resource, we analyzed the performance of top scoring proposals in various combinations. We conducted this analysis to ensure that we have evaluated the portfolio effect of each combination, and identified the effects of correlations between portfolio attributes, when making choices to meet our customers' needs. These portfolio considerations are summarized below.

Natural gas. Fuel and transportation prices have escalated significantly in the past 18 months. Industry analysis suggests that demand is outstripping current North American supply and is forecasted to increase, particularly in the power generation sector. Our RFP for energy and capacity confirmed this. About 80 percent of the bids we received were from gas-fired resources or were power transactions backed by, or indexed to, gas. While legacy supply is being depleted, new wells are not producing at levels needed to replace the depletion. As a result, new exploration and production sources of natural gas are being developed, such as liquefied natural gas (LNG), Arctic supplies, fuel switching and industrial conservation.

For now, the technology of choice remains gas-fired CCCT plants. Relatively short lead times, lower capital costs, greater environmental certainty and proven technology all make developing new plants an attractive option. However, the concern over escalating gas prices calls into question the industry's potential over-reliance on this technology. To address this concern, we have limited our long-term commitment to new gas-fired CCCTs to about half of our energy resource actions.

These matters also led us to select baseload energy resources for which we provide the gas commodity, or for which the power price is a function of changing gas prices, to approximately 60 percent of our needs. We chose the five- to 10-year fixed price power purchase agreements to provide valuable time in which to evaluate developments in natural gas supply, including the critical development of West Coast LNG facilities. This strategy also allows us to evaluate changing conditions related to coal developments (see below).

We also plan to manage our exposure to natural gas price volatility and transportation uncertainty by acquiring gas transportation and firm market storage capacity to support the operation of our existing generation and the proposed Port Westward plant. Our purchasing strategy will provide diversity in contract duration, location and execution.

Coal. Balancing the increased development of gas-fired plants is the industry's other major technology, coal-fired generation. Coal commodity costs remain competitive compared with natural gas, and are forecasted to be stable. However, lead times for new plants remain relatively long, capital costs are higher, and environmental concerns add cost exposure Our RFP confirmed these lead times. If development for a new coal plant were begun today, the facility would be ready for commercial operation in 2009 or 2010 at the earliest and, more likely, a year or two after that. For a potential coal plant in the State of Oregon, siting acceptance and coal transportation costs would be significant issues. For a plant outside Oregon, transmission availability would present a significant uncertainty.

We plan to enter into power purchase transactions with contract terms of five to 10 years, giving us time to commit to a coal-fired resource if that option proves to be environmentally and economically viable.

Wind generation. Among renewable resources, wind has come to the forefront. In our RFP, wind resource bids provided almost 900 MWa of potential energy supply, or about six percent of the total energy bids received. The economics of some projects are now competitive due to maturing technology, and subsidies from the ETO and the federal production tax credit. However, the intermittent nature of wind requires the addition of other resources to "fill in the gaps" to deliver a stable energy output over time. Given the relatively low capacity factor of wind, which typically ranges from 30 to 35 percent, transmission costs are a significant burden to wind economics. Transmission issues were a significant factor in virtually all wind projects proposed in our RFP. Our Action Plan includes the maximum amount of wind generation we can acquire at a market-competitive price.

The ultimate outcome of many of these key factors will not be known for many years. Therefore, we need to develop a portfolio that gives us the flexibility to allow course corrections as these factors play out. Providing for flexibility implies reducing reliance on any one technology, fuel type, transaction type, or length of commitment. A portfolio that allows changes in resource types over a five to 10-year period provides PGE the flexibility to adjust as the future plays out.

Applying These Considerations to the Action Plan

The analysis in our *IRP* identified a least cost and lowest price variance portfolio that was anchored by a gas-fired CCCT plant and supplemented by wind resources and other power transactions, such as tolling agreements or system purchases, plus upgrades to our existing plants. The energy portfolio listed in our Action Plan reflects this analysis, as shown by the following actions to be completed by 2006-07. While the following discussion repeats some details of our energy and capacity actions listed above, it does so in the context of our planning assumptions and analysis.

Energy

- First, we will capture about 115 MWa from our existing plants through upgrades (46 MWa), our renewal of our contract with the Confederated Tribes of Warm Springs for the Pelton and Round Butte hydro projects (63 MWa), and the extension of Bull Run hydro (6 MWa). This is about 15 percent of our need by 2007.
- The Port Westward G-class CCCT provides about 350 MWa of baseload energy, which meets about 45 percent of our energy need.
- Choosing among wind projects from our short list of RFP bids will provide up to 65 MWa energy, or about eight percent of our need.
- Choosing up to 150 MWa of fixed price PPAs fills up to another 20 percent of our need. These transactions are for five to 10 years in duration, providing for future flexibility to choose different resources, and the fixed prices support price stability.

- Choosing up to 150 MWa of tolling agreements provides optionality. We pay a fixed reservation fee for the right, but not the obligation, to bring natural gas to the plant to advantageously dispatch the plant. This could provide up to 20 percent of our energy need in 2007.

Reserving 125 MWa, or about 15 percent of our target, with terms consistent with our customers' choices maintains flexibility to accommodate the movement of non-residential customers on and off of annual cost of service pricing. This helps minimize what might be excess purchases and long-term commitments to resources.

Capacity

Besides the energy actions listed above, we also propose to take the following capacity actions.

- Our plant upgrades will capture 15 MW of capacity in addition to the energy gain, amounting to well under one percent of our capacity gap.
- Renewing the Tribes contract adds 102 MW of capacity above the energy acquired, and extending the Bull Run permit adds another 3 MW, totaling about six percent of our capacity needs.
- By working with customers who have large backup generators we can acquire up to 30 MW through our dispatchable standby generation program, at the rate of approximately 10 MW per year. This capacity is a cost-effective and reliable way to acquire up to two percent of our capacity.
- Acquiring up to 400 MW of peak tolling agreements helps cover our peak months, supplying up to about 20 percent of our capacity needs without incurring capacity costs during the rest of the year.
- Similarly, the seasonal exchanges we target, up to 100 MW, typically impose little or no incremental cost, and provide about five percent of our overall capacity requirements when exercised during periods of peak loads or surplus capacity.
- We may also acquire low heat-rate tolling agreements bid into our RFP, typically considered an energy product, if they are more cost-effective than more traditional capacity products bid to us or available on the market.
- By reserving 500 MW, or about 25 percent of our total need, to purchase within two years, we help ensure reliability at lowest cost by purchasing only what is needed to meet our peak loads as we anticipate they will occur within a fairly short-term period of time.

Conclusion

Throughout our resource planning process, from our evaluation factors and analysis to our selected energy and capacity actions, PGE has consistently focused on the three goals discussed with our customers at the beginning of our planning cycle. By improving our plants, building a new baseload facility, selecting proven technology and transmission paths, making appropriate purchases from third parties, and incorporating operating and planning reserves, we help ensure an electricity supply on which our customers can rely, even during periods of low hydro, severe weather, or plant or transmission outages.

By selecting a variety of short-, mid- and long-term commitments, and diversifying our resources, we minimize price volatility. Finally, by analyzing each new resource for cost-effectiveness over the entire life of the acquisition, and by scoring and short-listing RFP bids accordingly, we help satisfy our customers' requests that, besides being reliable and predictable, our prices also be reasonable.

PGE’s Energy and Capacity Needs

PGE’s needs for energy and capacity are a function of forecasting the amount of electricity our customers will use at any given moment, and the amount of electricity our resources will produce at any given moment.

We state this in terms of “any given moment” because the laws of physics require that load and resources match moment by moment or our service fails. Contingency planning is necessary because it is likely that load will differ from what we expect and, depending on the resource type, likely that production also will differ. We also state this as “electricity,” without regard to the type or duration of resource we may use to provide it. Type and duration are matters for the Action Plan, not for assessing need.

In the following chapters of this Plan, we discuss key components, or “building blocks,” of the amount of electricity we must provide to ensure reliable service to our customers. These components, listed below, are discussed further in the next chapter.

- How has our load forecast changed?
- Which customers should we plan to serve, given Oregon’s direct access program?
- What contingency reserves do we need for periods of poor hydrogeneration production, severe winter conditions, and extended plant failures?
- What are the effects on residential and small farm customers of losing physical power provided by BPA under the Regional Power Act?

Before we launch into those discussions however, it may be useful to describe how we distinguish between our various resource supply needs. Topics covered in this chapter include:

- Defining Energy and Capacity
- Types of Energy and Capacity Resources

Defining Energy and Capacity

The terms “energy” and “capacity” differentiate between the types of resource needs and sources, and describe the characteristics of a given resource. *Energy* generally refers to the average amount of electricity a utility will need over a given period, such as a week, month or year, while *capacity* is the amount of electricity a utility will need sporadically over the year at the times when customers place the most demand on the system.

With respect to a given resource, *capacity* generally means that amount of electricity the facility is capable of producing in a given hour, and *energy* generally means the amount of electricity the facility will produce, on average, over a year. Actual production is less than the capacity because of planned and forced outages, or mechanical issues that limit production. For some resources, the amount of energy will also be less than the capacity because of the availability of fuel. This is the case with hydro and wind resources.

Generally, the most desirable *energy* resources are those with the lowest cost when calculated on the assumption that the resource will run virtually all of the time it is available. The most desirable *capacity* resources are those that have the lowest cost of ensuring that the resource is available when needed, whether that is a reservation fee, or the capital, operation and maintenance costs of a owned resource, while still providing energy at a reasonable cost when load requires it. Given the choices we have, at times the best capacity resource will not necessarily provide energy at a reasonable cost – this is a trade-off to achieve the lowest fixed fee.

Figure 1, below, presents PGE's 2004 load duration curve. It shows the amount of electricity that we project our customers to require during every hour of 2004, ranked from the highest to the lowest usage hours. The load duration curve illustrates the great differences in our customers' requirements, which vary from a high of more than 3,630 MW to a low of less than 1,420 MW.

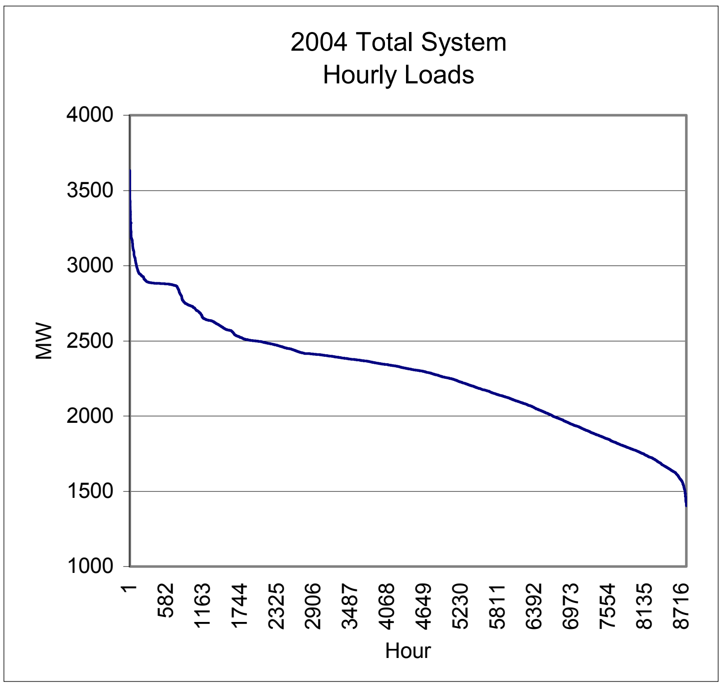

Figure 1. 2004 Load Duration Curve

Another way to look at our load variation is our 2004 forecast by month, shown below in Figure 2. This illustrates the highly seasonal nature of our customers' requirements, ranging from more than 2,550 MWa in December and January to less than 2,135 MWa in May and June. From this, one can see the highly seasonal nature of PGE's load.

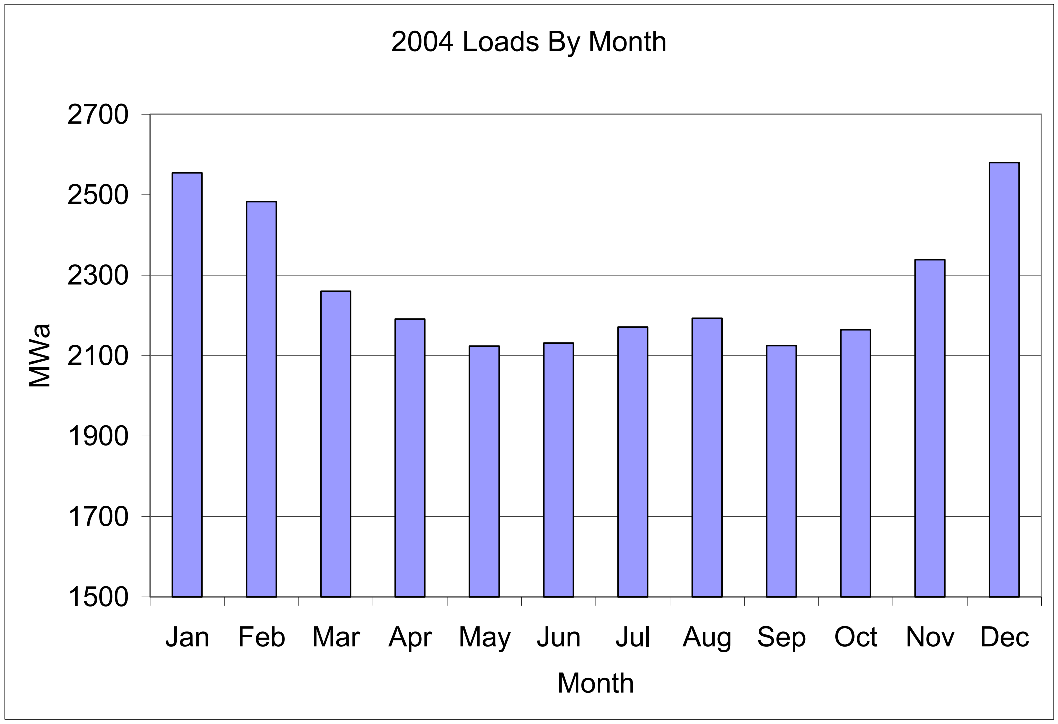

Figure 2. 2004 Forecast by Month

Types of Energy and Capacity Resources

Describing the types of energy and capacity resources available to PGE highlights that the array of choices is more of a spectrum than completely distinct categories. To be comprehensive, the list below includes all firm resources, even of short duration.

Energy Resources

- *Balance of month, day-head, and real-time contracts* – Non-resource specific contracts available online and over-the-phone. These resources vary in size from standard lots in increments of 25 MW to odd-lots less than or not divisible by that amount. Intra-month markets show good liquidity, and agreements typically use standard terms and conditions defined by enabling or master agreements.
- *Standard "trading" contracts* – Non-resource-specific contracts available in monthly, quarterly and annual durations online and over-the-phone, and generally available in flat blocks for on- or off-peak hours. The standard nature of the shape, size, and contract terms allows easy trading of these among utilities, brokers, and other market participants as these entities seek to manage risk. Some multi-year standard contracts are available, but the market in these is not always liquid.
- *Structured or custom contracts* – Contracts that are negotiated, rather than traded, based on what the seller has capability to provide and what the buyer needs to acquire. Custom terms, conditions and contracts are the norm, and examples include PGE's Mid-Columbia contracts. Our contract with the Confederated Tribes is a longer-term agreement.

- *Tolling contracts* – Resource-specific contracts that provide the buyer the right to generate electricity according to various fuel arrangements, including that the buyer acquires and delivers the fuel or that the buyer pays an index price for fuel. Today, these agreements typically are used only for plants fueled by natural gas, although we did receive through our RFP a biomass tolling proposal for a plant fueled by burning wood scrap. The seller generally commits to provide a certain availability and heat rate, although *force majeure* excuses performance. Many contracts limit damages for non-performance to the amount of compensation paid the seller, rather than covering the cost of replacement energy. Gas tolling agreements are available in durations from a few months to more than 20 years.
- *Owned resources* – Full or partial ownership of a specific generating resource, such as Beaver, of which PGE owns 100 percent, and Colstrip, of which we own 20 percent, sharing the resource with five other parties. The Northwest has a long history of shared generating resources.

Capacity Resources

- *Fixed Strike Daily Capacity* – Non-resource specific contracts typically of up to two years that give the buyer the right during specific months to schedule daily on-peak energy in at least four-hour continuous blocks, subject to energy and demand charges.
- *Exchanges* – Non-resource specific contracts, for a few months up to several years, that give the buyer the right to receive energy in exchange for returning an equal quantity of energy within a specific period such as a day, 168 hours, or a season. For daily products, receipt is during on-peak hours and return is during the off-peak hours. For 168-hour products, receipt and return must occur within the period. Seasonal products permit receipt in one season, such as December to February, and return in another season, such as July to September.
- *Peak Tolling* – Contracts that provide the buyer the right during a given month to schedule daily on-peak energy at a capacity charge. As with energy tolling, the buyer pays for the fuel and may or may not also arrange for the fuel. Contracts may be resource-specific or provide “virtual” tolling from a system, and range in durations of a few months up to several years.
- *Owned resources* – Some owned resources, such as simple-cycle combustion turbine (SCCT) plants, are considered to be capacity, rather than energy, resources.

In a predictable and stable world, a utility would acquire energy resources right to the point that it becomes more economic to acquire capacity resources, but in reality this is impossible, given the uncertainties of load, resource performance and cost. We must make decisions based on imperfect information, aiming for an end result and leaving room to adjust our course to increase the likelihood of reaching the results desired.

Update of Building Blocks and Signposts

In the 10 months since we filed our *Supplement*, we have continued to monitor our business and regulatory environment. Projections of PGE's loads have changed, our customers have again indicated their preferences for certain rate structures, and we have done further analysis on hydro planning and capacity resources. In this chapter, we update selected building blocks and signposts previously addressed in our *IRP* and *Supplement*. Topics include:

- How Has Our Load Forecast Changed?
- Which Loads Are We Planning to Serve?
- What Is Our Hydro Planning Standard?
- What Is Our Planning Reserve Margin?
- What Are Our Transmission Constraints
- How Can We Use Low Heat-Rate Tolling Resources?
- How Do We Think About Uncertainty?
- What Risks Do We Manage in Our Power Supply Portfolio?
- How Do Regional Power Act Benefits Affect Residential and Small Farm Customers?

How Has Our Load Forecast Changed?

Our energy and capacity needs depend on our expected load. Since filing the *Supplement*, we have revised our forecasts and updated our IRP modeling tools to reflect our October 2003 short-term forecast. Energy and capacity growth rate forecasts have declined somewhat. The changes, reflected in Figures 3 and 4, below, relate primarily to our expectation that the current economic downturn will last longer than previously expected.

Peak load is down substantially more than our energy load, indicating that our system load factor is increasing. We attribute much of this to increased air conditioning load in the summer months. This increases annual energy consumption without affecting our peak load, which on a planning basis continues to be in the winter.

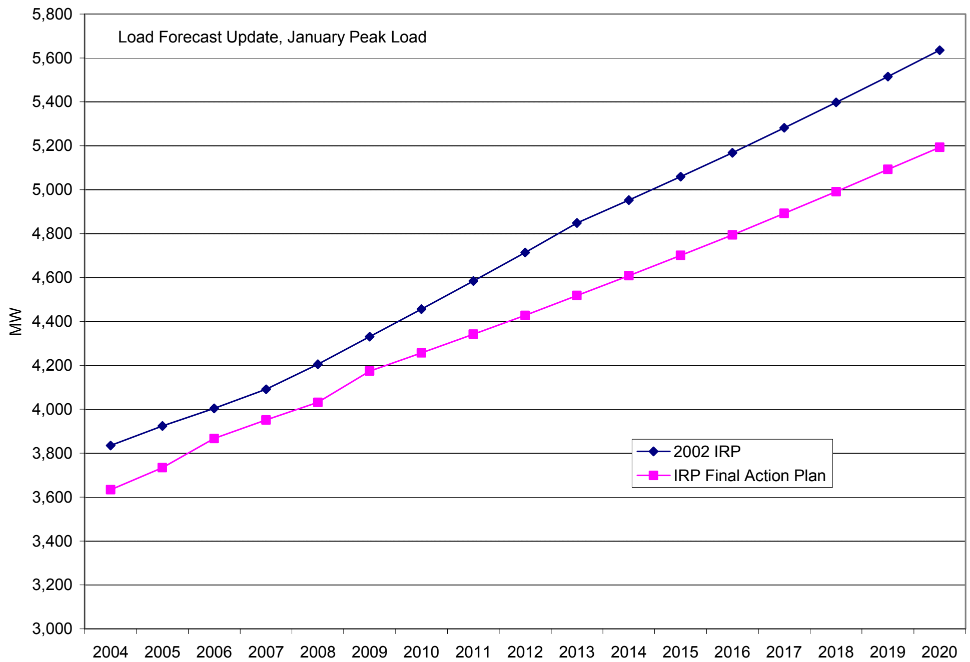

Figure 3. Updated Load Forecast (January Peak)

Figures 3 and 4 assume a projected system load that includes customers on Schedule 83 indexed rates, but excludes those on Schedule 483 five-year opt out.

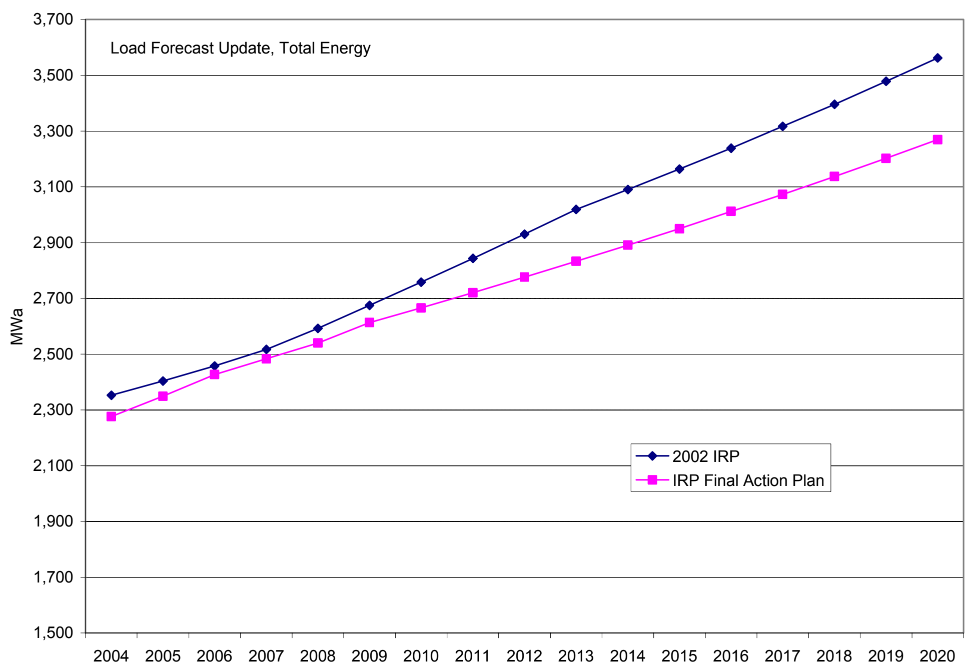

Figure 4. Updated Load Forecast (Total Energy)

Which Loads Are We Planning to Serve?

The current status of state law places PGE in an awkward position:

- We must offer all customers a "cost of service rate" until the Commission, by order, exempts a given class from this requirement; the Commission has not yet done so for any class of customer.
- The Commission must ensure that the provision of direct access to some customers does not cause the unwarranted shifting of costs to other customers and, presumably, act to minimize the acquisition of any resources that might be stranded when and if customers choose to get electric service from other suppliers.

To overcome this dilemma, PGE has twice offered a voluntary program under which business customers with larger loads can provide notice that they will rely on non-PGE resources for at least five years and return to PGE service with at least two year's notice. Load under this voluntary program is approximately 10 MWa. We have removed this amount from our load forecast and are not planning to serve it until we receive notice from the customers involved.

A related issue arises from the market-based rate options that PGE developed and implemented in 2001. These have proven more popular than direct access, with between 115 and 168 MWa selecting something other than an annual cost of service rate. The following table shows the elections since 2002.

Table 5. Historic Market-Based Loads (MWa)

Schedule	*2002*	*2003*[B]	*2004*
83 Indexed	123.7	88.2	115
99[A]	44.5	44.2	n/a
Totals:	168.2	132.4	115.0[C]

[A]*Schedule 99 is a daily price option for a large, non-residential customer that expired at the end of 2003.*

[B]*Figures for 2003 combine actual and forecasted actions.*

[C]*Total for 2004 is an estimate pending updated load forecast.*

Because these index and non-shopping credit customers are eligible to return to an annual cost of service rate with relatively little notice, we should not exclude them from our planning.[1] We have recognized these choices, however, in selecting the duration of our resource choices. We plan to acquire approximately 125 MWa on a short-term basis, recognizing the desire of some customers regularly to choose between the price of electricity we acquire in advance and the price of electricity set only quarterly or monthly in advance, or even priced daily after-the-fact. For customers on indexed rates, we will generally purchase

[1] The "Shopping Credit," or Shopping Incentive Rider provided by Schedule 130, allows non-residential customers generally with loads less than 1 MWa at a given site to receive a credit of 0.5 cents per kWh to their bill when taking direct access service from an ESS. The credit is limited to 10 percent of our eligible load, and terminates December 31, 2006.

consistent with the index, *e.g.*, daily purchases for daily indexed customers. If the load served on indexed rates or by ESSs grows, the resulting reduction in our cost-of-service load can offset other forecasted load growth.

Customers on Schedule 583, representing approximately 35 MWa of load, will receive shopping credits under Schedule 130 when served by an ESS. As mentioned earlier, the shopping credits allowance expires at the end of 2006. Depending on their contracts with their ESS, customers may return to any other applicable PGE tariff. Because it is not clear whether these customers would go to an ESS in the absence of the shopping credit, we consider it prudent to include this load in our long-term planning until we receive further evidence to the contrary. The size of this load is not large enough to have a major adverse effect on the overall results of our resource planning.

To meet the requirements of ORS 757.607(1) that restructuring not shift costs among customer classes, we may need to revise our tariffs to ensure that the costs or benefits of these short-term purchases accrue only to those eligible annually to choose between an annual cost of service rate and the various market-based options, or those customers that do not follow their initial opt-out determinations.

What Is Our Hydro Planning Standard?

For what we call "run-of-the-river" hydro resources, capacity and energy are about the same. While we can increase production for a given hour by a small amount, the ability to do this is limited by actual stream flows.

For hydro resources with storage, however, planning is more complex. The average energy the plant can produce is a result of precipitation and storage. Using stored water, operators can produce nameplate capacity during any given hour. Using the stored water, however, is likely to affect the average energy the plant can produce, particularly if the capacity need extends beyond an hour, which can occur during peak needs caused by extreme cold weather. Cold and dry conditions exacerbate this. At some point, the extent to which we rely on these hydro resources for capacity affects the extent to which we can rely on them for energy under average water conditions.

Moreover, all hydrogeneration – run-of-the-river or storage-based – faces the constraint of precipitation. Less than average precipitation affects the energy available to a large number of utilities in the Northwest, directly or indirectly through contracts including those with BPA. Under poor water conditions, all of these utilities will need to find resources to provide electricity required by their customers.

While there is transmission available to bring in the needed energy from a wide variety of sources throughout the WECC, it is likely that electricity purchased under such conditions will come from resources that produce electricity at a higher cost. That is because resources producing at a lower cost will be under long-term commitment to other retail load, and because sellers will expect buyers to accept higher prices, given the shortage conditions.

Under an extreme water-driven energy shortage, depending on the amount of excess energy production capability in the region, it is possible that electricity would not be available at any price, threatening reliability.

This is a significant planning and ratemaking issue for us, given that we currently rely on PGE-owned and contract hydro resources, under normal water conditions, for approximately 26 percent of our customers' current energy needs and 37 percent of our customers' current capacity needs.

In the *Supplement*, we proposed to plan for *poor* hydro conditions by acquiring additional long-term supply. We promised to further evaluate the economics of this proposal in this Proposed Action Plan. We are now proposing to plan to *average* hydro conditions, but intend to take certain resource actions in the event of tight supplies in the region, as further discussed in this chapter.

We evaluated the economics of holding a "long" energy position as a hedge against low hydro conditions. For a modest but ongoing annual fixed cost increase, a hydro hedge could reduce replacement cost volatility by capping the replacement cost for the lost hydro generation At the same time, this long energy position displaces winter peaking capacity that we otherwise would need to acquire, thus avoiding the associated capacity charge. Our analysis suggests that, over time, this approach could be more economic than separately acquiring winter peaking capacity and summer energy for poor hydro years. Being able to cap the cost for replacement energy also moderately reduces market price risk.[2]

However, planning for lower than average hydro conditions is only a partial hedge for hydro variances. It provides a natural hedge against price excursions, but cannot provide protection for the large replacement cost of low-cost hydro-generation *versus* the fuel cost of even a 7,000 heat rate CCCT. The bulk of the cost exposure cannot be hedged by maintaining a long energy position, and a power cost adjustment is still required.

Low hydro conditions can be hedged with either a low heat rate CCCT, or with a resource that has a higher heat rate but a lower capital cost, such as duct firing or an SCCT. Because the fully-allocated cost of incremental duct firing for the assumed number of operating hours is less than the related, fully-allocated cost of a base-load CCCT, it is more economic than acquiring additional base-load CCCT.

We cannot be certain about how a resource may subsequently compare to the market, so another way to mitigate poor hydro is to look about 18 months ahead at the region's resources. If the regional load-resource balance looks like it will be tight, we may propose to acquire options on short-term resources ahead of the spot market, in advance of *any* knowledge of what the water year may bring. This would provide a limited hedge in a way similar to the scenario described above.

From a planning perspective, we propose the following guidelines:

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[2] Idaho Power and the Idaho Public Utilities Commission found that planning to a 70 percent hydro standard was a cost-effective hedge against hydro conditions.

- If it appears that the WECC energy and capacity reserves are shrinking, we may propose to acquire, and include in the annual reset of net variable power costs, the cost of option premiums to hedge the price risk of below average water conditions. On an expected cost basis over time, this approach is likely to cost less than other options and also has a lower risk of causing price volatility.
- We will use any CCCT duct firing capability we have available during poor water conditions, if required, and any other time that it is economic to do so. That means duct firing serves a dual purpose. It can be used during low hydrogeneration conditions and to meet winter peaks. In either case, we would use it when a more economic alternative is unavailable.

For ratemaking purposes, we are seeking outside of this resource planning process a better way to reflect the variability of hydro production in the rates our customers pay.

What Is Our Planning Reserve Margin?

In our *Supplement*, we proposed a six percent planning reserve margin, in addition to our required six percent operating reserve.

Weather conditions typically drive capacity needs – heating in the winter and cooling in the summer. Although we calculate the reserve margin from the peak hour, most weather-driven events will last longer. A severe winter or summer episode of three to four days is not uncommon. Demand tends to grow over such periods, peaking in the final hours as customers grow weary of the continued cold or heat. As a case in point, we forecasted a 1-in-2 peak of approximately 3,600 MW for 2007 but, as of this writing, have exceeded that figure for 2003-04 with a peak demand in January of 3,942 MW.

Plant outages also require replacement capacity. Our largest singe-shaft risk is our Boardman plant, where an outage could create an immediate need for 348 MW, while still maintaining required operating reserves. It is appropriate to have a contingency plan for such potential weather or outage occurrences.

Theoretically, physical reliability is never in question unless the region as a whole lacks adequate capacity and transmission constraints prevent available supply from reaching the point of need. Transmission constraints do affect the WECC, however, and a significant portion of the region's capacity is in hydro generation, which is subject to precipitation uncertainty. A large thermal outage during a dry year, coupled with an extreme weather event, could threaten physical reliability.

While the odds of physical failure to deliver electricity may be low, those of facing high prices are not. The California experience of 2000-01 proves this. Poor hydro conditions in the Northwest, coupled with many long-term thermal plant outages, resulted in high prices and rolling blackouts. The Federal Energy Regulatory Commission (FERC) based its proposed Standard Market Design (SMD) requirement of a minimum capacity reserve margin on the adverse effects of shortage on price and market behavior. Although the future of this requirement is in doubt, the reason remains valid. If a significant number of utilities in the WECC plan to low reserve margins, the region will face price spikes and, at the outside, physical reliability problems.

The annual "insurance" costs, *i.e*., the ongoing fixed costs, of maintaining this planning reserve are in the range of $4 million for 235 MW of seasonal capacity, to $23 million for year-around capacity. On the other hand, the potential cost of replacement power, if available, or the lost output in the case of a widespread outage, could quickly overwhelm this cost. A comparison of utility planning reserves in provided in Appendix 2.

For all of these reasons, PGE urges the Commission to acknowledge a six percent planning reserve margin above the required six percent operating reserve. Our guideline calls for us to meet more than twice this need with relatively short-term purchases, allowing for adjustments in strategy should circumstances show it unnecessary to carry this amount of reserves.

What Are Our Transmission Constraints?

The Pacific Northwest power grid is constrained in a number of places, particularly south- and west-bound. The closest constraint for PGE is just north of our service territory. The constraint-free area is limited to the Columbia River Gorge, west of John Day, and the Willamette Valley, south of PGE.[3] Most of the bids received through our 2003 RFP were located outside of the constraint-free area and few came with provisions to deliver the power products directly to our service territory on a firm basis.

We have a significant interest in the constraint north of Portland because of our ownership of the Trojan lines. Though these lines are within the south of Alston cut-plane, we directly control them. This available transmission provides a unique benefit to PGE and our customers, in that any generation resource that can be directly connected to these lines is assured firm delivery. We depend heavily on BPA for delivery of over 2,200 MW of our remote resources. We do not control that delivery system, and are subject to outside decision-makers on such issues as user fees. PGE currently pays about 10 percent of BPA's net transmission revenue requirements, and this will increase with acquisitions proposed with our recommended action plan.

The short list developed from our 2003 RFP responses included projects within and outside the constraint-free area, based on scoring that factored transmission costs and risks into pricing and non-pricing scoring. Several of the short-listed products require, or are facilitated by, PGE's point-to-point Rocky Reach transmission contract. We have executed a transmission service agreement with BPA extending service through June 1, 2005, including roll-over rights. This allows us to take delivery of energy at Mid-Columbia, and deliver it to our

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[3] In the future, PGE is likely to experience constraints with transmission west of the John Day cutplane, but how quickly that occurs depends on the timing and location of generation development. This constraint risk is reduced by new projects planned or underway along the I-5 corridor between Portland and Seattle, but is exacerbated by new projects east of the Cascades..

system *via* our Rocky Reach transmission contract. This improves our economics for power purchases with the Mid-Columbia as the point of delivery.

The practical effect of the transmission constraints is the risk of future cost premiums imposed by a constraint management system to help cover the cost of significant transmission upgrades. Because we typically do not know about a non-delivery in advance, we risk paying for costly replacement power. BPA is seeking to implement conditional firm transmission products that will squeeze out non-firm availability. These factors favor locating new resources close to end-users.

How Can We Use Low Heat-Rate Tolling Resources?

We have a limited number of capacity bids on our short list, and may face challenges filling our mid- to long-term target. Depending on the outcome of negotiations, we also might have more than enough attractive energy bids to fill our energy deficit. If this occurs, we will consider filling some of the capacity deficit with short-listed RFP energy bids. We believe this potential strategy has at least two advantages and one disadvantage.

The first advantage is that the economics of purchasing a low heat-rate resource may be better than those of purchasing a high heat-rate unit. This is also true for long-term contracts covering essentially all of the capital costs of these resource alternatives. The expected variable margins of a CCCT are much higher than those of a SCCT. However, the capital costs of a combined-cycle unit are only somewhat higher than those of a simple-cycle machine, potentially making CCCTs a lower net-cost resource for customers.

Another advantage is that loads are not evenly distributed across the year. Even if we are in energy load-resource balance on an annual basis, in some months we will be somewhat deficit, *e.g.*, our monthly energy loads in December and January are approximately 25 percent higher than in June. Covering some portion of our capacity deficit with low heat-rate resource alternatives would partly alleviate our short energy position in high load months.

However, lower heat-rate resources have higher fixed costs, primarily due to higher capital costs per installed kilowatt. For example, if the capital costs of a CCCT were $2.00 per kW-month higher than those of an SCCT, annual fixed costs per 100 MW of resource would be $2.4 million more.

Even if higher variable margins available from CCCTs on average more than cover their higher fixed costs, this will not occur every year. In years in which spark spreads are low, even low heat-rate units will not dispatch very often, resulting in variable margins that are insufficient to cover fixed costs. This could become a bigger problem if spark spreads are low over a period of several years.

Given these considerations, it may make sense to fill some portion of our capacity target with short-listed energy bids, while simultaneously reducing the amount of capacity acquisitions we might otherwise undertake. It is not possible to know what the amount should be at this point. This decision will be the result of business judgement and a comparative economic analysis, including both the fixed costs and expected variable margins, of lower heat-rate proposals *versus* higher heat-rate alternatives.

How Do We Think About Uncertainty?

One of the improvements to resource planning included in the Commission's adoption of a least-cost or integrated approach was the explicit consideration of uncertainty. The intervening 15 years have brought us a better understanding of the uncertainty that existed even in the late 1980s, and also revealed some new areas of uncertainty. For example, even in 1990, the future price and availability of natural gas was uncertain. We did not appreciate, however, that the range of prices could include $1 per MMBtu and $40 per MMBtu. In 1990, however, few thought about credit support for performance failure, because most suppliers were also utilities and unlikely to go bankrupt.

Resource choices are subject to uncertainty *after* they are made. No resource choice is immune from uncertainty regarding whether the resource will perform as we expect, and will provide the expected value, *i.e.*, will compare favorably to what becomes available.

Removing one uncertainty often triggers another. For example, locking in a price for a given power purchase removes the uncertainty about price volatility but opens the uncertainty about value. Choosing resources becomes an exercise in determining the magnitude and likelihood of competing uncertainties, and adding that to a base comparison of the costs and benefits of the various resources known at the time the decision was made.

Because not all resource choices have the same sets of uncertainty, diversifying our sources can mitigate uncertainty. Similar to an investment portfolio, resource diversification is critical to achieving value over time, notwithstanding uncertainty. For example, while CCCT units based in Washington state, all supplied by Sumas gas and delivered to the Mid-Columbia hub, might be the lowest cost supply portfolio identified at the point of decision, the associated uncertainty would significantly affect our ability to achieve price stability and predictability. The single natural gas source would increase fuel price risk.

The following list, while not exhaustive, explains the preferences we applied to spread and mitigate uncertainty through diversification.

- *Cost* – Cost is a dominant driving factor for any new resource decision. Absent offsetting factors, we will choose resource actions with the lowest costs. However, a resource with the lowest lifetime cost may not have the lowest initial price effect for customers. That is frequently the choice between contracts *versus* owned assets under traditional rate base treatment. The corollary is that rate-based resources tend to have costs lower than their alternatives later in their life cycles.
- *Size* – We generally prefer resources in smaller sizes for several reasons. If the resources are physical plants, smaller shafts reduce the consequences of a forced outage. If the resources are contracts, smaller sizes spread credit risk. Smaller sizes generally also allow for more diversity in the duration of resources and thus, greater ability to respond to future changes.

- *Existing* versus *proposed* – Given equal heat rates, PGE may prefer a plant that already is operating to one that still has risks associated with development, construction, and start-up. Existing plants require significant due diligence, however, to identify latent issues arising from previous design, construction and maintenance decisions.
- *Ownership* – Assuming equivalent cost, we prefer to own a material portion of new generating capacity. This allows for a greater portion of the supply cost to be depreciation and return on equity, which benefits customers directly by improving our financial health and leading to a lower cost of debt and equity. Ownership also allows us flexibility that most contracts cannot, including the option of mothballing resources for an extended period if uncontrollable forces create a significant regional surplus.
- *In-state* – Investment within the State of Oregon creates new, high-quality jobs and provides a beneficial multiplier effect on our economy. Projects nearer our service territory provide a boost to the economy in our customers' area. Also, taxes on fuel in other states add to the variable costs of power. All else being equal, we prefer resources within Oregon.
- *Transmission firmness and proximity to load center* – In general, resources near our load center, or provided over a firm, uncongested transmission path provide greater reliability and reduce exposure to congestion charges. We prefer nearby resources to those that are more distant or have uncertain transmission rights.
- *Fuel source diversity* – For plants or unit-specific contracts, we typically prefer a project capable of receiving fuel from two or more sources. For a portfolio, a diversified set of resources that includes wind, coal, gas, hydro, and system purchases best manage inherent fuel and technology risks.
- *Fuel price volatility* – Generally, resources with little fuel price volatility are preferable to those with significant fuel price volatility. Common trade-offs to this include relatively high fixed costs and variability in fuel availability, such as water or wind.
- *Contract durati*on – Long-term projects lock in fixed cost commitments for a long period of time. Mid-term projects require rollovers and can contribute to customer price volatility. Mid-term transactions also allow different resource choices when a commitment ends. From a portfolio perspective, a mix of different contract lengths is best.
- *Dispatchability* – Some resources, such as wind, are not dispatchable, or have limited dispatchability. Projects that can be dispatched at will are preferred, all else being equal. This is particularly necessary in a region with a large proportion of hydrogeneration because of the economic benefits of displacing thermal resources when water conditions are better than average.
- *Gas* versus *electric indexing* – While gas tolling is more volatile in price than a fixed contract, it is considerably less volatile than a contract indexed to Mid-Columbia or some other electric market index. All else being equal, fixed price contracts are preferable to minimize price volatility.

What Risks Do We Manage in Our Power Supply Portfolio?

Although most generating resources today provide capacity that is flat across the year or within a day, electric energy demand varies dynamically from month to month, and even from hour to hour. Most of these fluctuations are caused by seasonal changes in temperature and irregular customer usage patterns. Combining variable energy needs with static generating resources means that we must maintain in our portfolio energy resources that can vary production output to allow for a minute-by-minute balancing of energy demand to supply. In the Pacific Northwest, this balancing is accomplished primarily through hydrogeneration.

Besides seasonal and hourly requirements to balance loads and resources, we must also be prepared to respond to unplanned changes in customer demand, loss of generation, and changing regional market dynamics. Unforeseen plant outages, deviations in temperature or weather patterns, or changes in economic conditions in the region can lead to unexpected variations in customer demand and the availability of energy supply. At times, without careful management, these changes could have sudden and significant effects on reliability of supply and wholesale energy prices.

PGE performs the continuous and integrated process of evaluating, identifying and acquiring resources that deliver energy at the highest value – with the least amount of risk in meeting customer loads. Like its counterpart in investment management, a power supply portfolio has *assets*, such as generation, purchased power, fuels, electric transmission, gas transportation. A power supply portfolio also has *component risks*, such as market price, credit default, unit outage, weather events and fuel supply, to name a few. Using portfolio management methods, PGE manages overall risk by considering the dynamic and continuous interaction of resource decisions and fundamental drivers on the value of our power supply portfolio, and ultimately the price and reliability of power delivered to customers.

Portfolio risk is the chance that unexpected changes in one or more of a variety of factors may alter the value of a particular commitment or asset. Our power supply portfolio includes many specific component risks that we actively work to identify and mitigate. Each of these risks can affect our ability to reliably meet customers power needs at the established retail tariffs. Some of the primary portfolio risks that we manage on behalf of customers are listed below.

- *Price Risk* – Potential fluctuations in prices of the underlying energy commodities.

- *Credit Risk* – Potential adverse occurrence of a counterparty's ability to pay its obligations.

- *Counterparty Performance Risk* – Potential adverse occurrence of a counterparty's ability to perform on an agreement or obligation, such as an agreement to deliver power.

- *Volumetric Risk* – The risk that supply or demand volumes will vary from forecasted quantities, resulting in a potential economic loss or gain due to changing commodity market prices. For example, an unforeseen extreme cold weather event typically results in a sharp increase in the demand for electricity and natural gas. The likely outcome is the combination of increased electric consumption with rapidly increasing energy prices in the wholesale market. This combination of higher demand and higher prices creates an increased and unplanned obligation to acquire power in a market where prices are rising. The result is an economic loss if the price to purchase electricity to cover sales is higher than the electricity sale price.

  Another example of volumetric risk is varying seasonal precipitation and the resulting fluctuations in our regional hydrogeneration. In any given year, actual precipitation and snow pack may be higher or lower than what we expect and plan for in advance. In years when precipitation falls below average, our resulting hydrogeneration also falls short of expectations. Because other utilities in the region also depend on hydro production, below-normal hydro conditions force us to purchase replacement power in a market with greater demand and higher prices.

  We must buy power to meet our obligation to serve retail customers, which means that we face an inherent portfolio risk due to the requirement that we serve all customer loads regardless of the uncertainties of a dynamic supply-demand environment.

- *Basis Risk* – The risk that the value of a futures contract or an over-the-counter hedge will not move in parallel with that of the underlying commodity exposure. Other forms of basis risk include product basis, arising from mismatches in type or quality of hedge and underlying product, *e.g.*, power with natural gas, and time or calendar basis, *e.g.*, hedging an exposure to physical deliveries in December with a January forward contract. Basis differentials are generally due to differences in geography, quality, delivery infrastructure, weather, time, and options valuations.

Combining internal tools and staff expertise with continuous market participation allows PGE to optimize the economic value of internal resources to provide reliable power at reasonable prices to meet customer needs for any given hour. By constantly identifying, evaluating and diffusing risk, we strive to maintain reliability and mitigate the inherent costs of delivering energy to customers in a world of variable demand and uncertain supply.

How Do Regional Power Act Benefits Affect Residential and Small Farm Customers?

The Regional Power Act gave benefits from the Federal Columbia River Power System (FCRPS) to PGE's residential and small farm customers. Currently, these include monetary benefits based on 232 MWa of power, and a power purchase of 258 MWa. However, based on negotiations that have occurred since we filed our *Supplement*, we assume that, after September 2006, BPA will no longer provide these benefits in the form of power.

A settlement for the five-year period beginning October 2006 is pending. It would provide our customers with benefits, which would vary on an annual basis with (forecasted) market electric prices. The annual benefit calculation would be the product of 560 MWa, and the difference between the relevant BPA cost-based rate and a forward curve based forecast of market prices. Benefits would increase with increases in forecasted market prices, and *vice versa*, providing some protection against market price fluctuations. However, the settlement would impose a $25 million floor and a $76 million ceiling on the annual benefits.

The formula for benefits in the settlement could act as a financial instrument price hedge. We might be able to rely on short-term purchases for our residential and small farm customers during this period while still achieving price stability and predictability. However, we do not think we should pursue this strategy for a number of reasons, discussed below.

- Parties to the proposed settlement may not reach closure. If parties do not agree, the form of our customers' benefits is unknown at this time.[4]
- The floor, and particularly the ceiling, limit the ability of the product to protect customers from very high market prices. This raises the possibility of viewing the 560 MWa BPA product as an effective hedge, but only for an exposure substantially less than 560 MWa.
- Thinking of the BPA product as a hedge for a lesser exposure still leaves several problems unsolved. For example, the complex procedure for determining the market price forecast used in the annual benefit calculation takes approximately one year to complete. Therefore, implementation of the hedge would be hindered by mismatches in period and execution timing, potentially introducing more, rather than less, variability into the rates of our residential and small farm customers.
- The BPA rate used in the benefit calculation would be subject to revision if BPA's costs increased significantly. This is a further source of uncertainty for the potential BPA benefits.

For all of these reasons, we intend to treat FCRPS cash payments, if and as they occur, as a credit to the cost of resources PGE has otherwise acquired for residential and small farm customers.

[4] All parties must agree to the settlement, and currently at least one of the public entities is still opposed.

Update of Our Load-Resource Balance

As a result of the changes described above in "Updated Building Blocks and Signposts," we have updated our load-resource balance for energy and capacity. In this chapter we reconcile these updates to the information provided in our *Supplement*, and describe the resulting new projections for loads and supplies. Topics include:

- Reconciling with the *Supplement*
- Energy and Capacity Requirements

Reconciling with the *Supplement*

Table 6, below, shows how we recalculated our load-resource balance, beginning with information contained in our *Supplement*. We now show our full capacity needs *before* filling our energy needs, because this gives a more accurate accounting of actual capacity requirements.

The most significant change in assumptions from our *Supplement* is that we no longer assume that we will receive any physical power through BPA's Residential and Small Farm Exchange. We also assume that less load will move to direct access on a long-term basis. While these assumptions increase our load demand, other assumptions, such as a reduced load forecast and use of average hydro to measure our resources, work in the other direction. The following table reconciles the energy and capacity needs identified in our *Supplement* to those shown above in Table 2.

Table 6. Reconciliation of *Supplement* to Proposed Action Plan

	Energy (MWa)	*Capacity (MW)*
2007 Resource Need in *Supplement*	650	950
Remove capacity credit from energy actions in *Supplement*	-	720
Remove assumed 2007 BPA power	140	240
Move to average hydro*	(115)	-
Reduce estimate of customers not served by PGE	115	120
Updated (reduced) load forecast	(30)	(140)
Updated 2007 resource need	760	1,890
Includes minor rounding.		

* We stated in our *Supplement* (p. 2), that moving to a critical hydro planning standard added 125 MWa to our customer load. This was based on PGE and contract hydro resources as of 2003. In moving to an average hydro standard, we subtract only 115 MWa from our 2007 load because we lose some of the energy acquired through our Mid-Columbia (hydro) contracts by 2007.

Energy and Capacity Requirements

Because the focus of integrated resource planning is long term, and because we have a major energy resource contract expiring late in 2006, we prepared the tables below based on 2007 requirements. PGE has energy and capacity needs in 2005 and 2006 as well, most of which we will meet with short-term purchases in a manner similar to that of the last several years. Some of the contracts offered under our RFP, however, will start in 2005. We will update OPUC Staff and IRP participants regarding our strategy for short-term energy and capacity acquisitions and our actual actions during the quarterly meetings discussed in the "Introduction."

While the energy and capacity balance tables in Appendix 1 show our energy and capacity needs in 2007, the spirit of integrated resource planning requires that we take a long view as well. The charts below show upcoming changes in our current portfolio of resources.

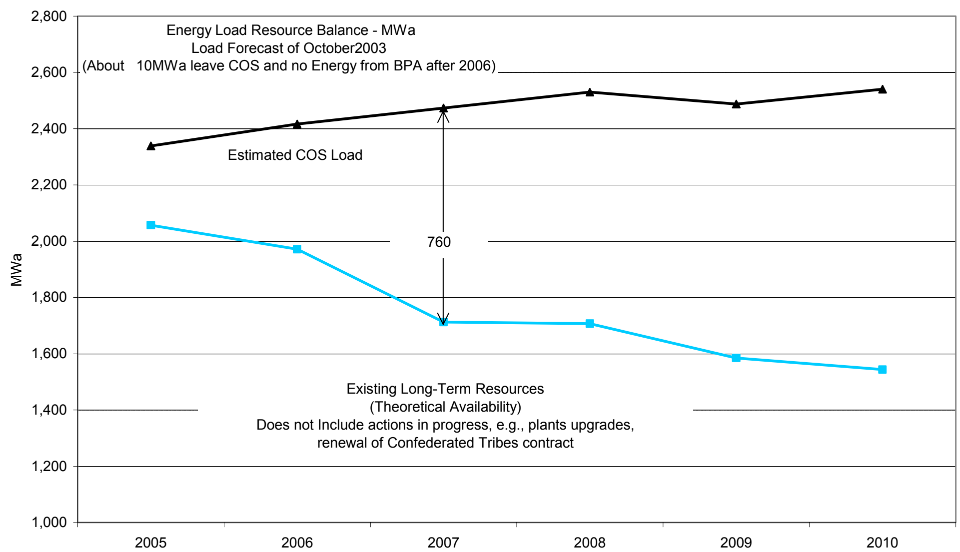

Figure 5. Energy Load-Resource Balance (MWa)

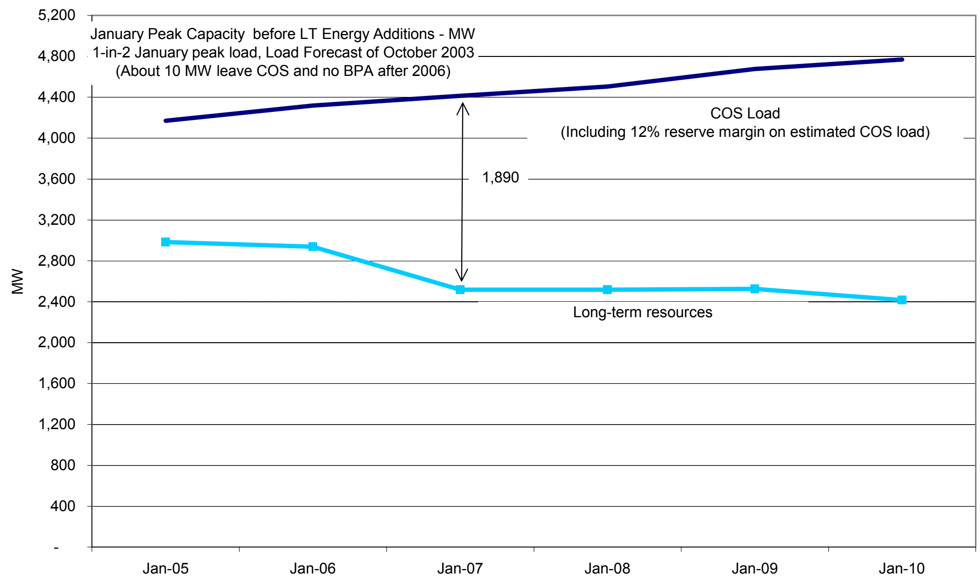

Figure 6. Capacity Load-Resource Balance (MW)

PGE's need to acquire new resources over the next 20 years is evident, even if our load did not increase. These graphs confirm that we should take action to fill our current deficit and return to balance, so that we have a solid base from which to address the upcoming needs caused by future contract termination, resource retirement and load growth.

Requests for Proposals – Energy, Capacity, Gas

Since filing our *Supplement*, we have completed three requests for proposals or information from potential energy and capacity providers, and from natural gas providers. This chapter summarizes the following activities:

- RFP for Energy and Capacity
- RFP for Natural Gas Commodity and Transportation
- RFI for Demand-Response Products
- What We Learned About the Market
- Status of Post-RFP Negotiations for Energy and Capacity

RFP for Energy and Capacity

In consultation with the OPUC and other participants in PGE's public resource planning process, and in accordance with OPUC Order 91-1383 (UM-316) "Competitive Bid Order," on June 18, PGE issued an RFP for power supply resources. Bidding closed on July 23, by which time we received 105 bids from 43 counterparties. We disqualified 14 bids and one was withdrawn by the bidder. Of the bids received, 66 were for energy products, including 27 tolling proposals. We received 26 bids for ownership of energy facilities, and 13 proposals for capacity products. After notifying bidders of our short-list selection, two short-listed bids were withdrawn, one for energy and another for capacity.

Reviewing, Ranking and Selecting Bids

In selecting the RFP short list, PGE used a first-price, sealed-bid format as required by the OPUC's Competitive Bid Order. Under this format, bidders may not update pricing during the scoring and evaluation period. We used the first prices provided by bidders to select our short list of candidates, and are currently negotiating price and non-price elements during post-RFP negotiations. PGE requested additional information regarding many of the proposals received.

We evaluated the bids using a two-step process.

- *Assessment of Pre-Qualifications* – First, we screened bids according to pre-established qualifying criteria, *i.e.*, minimum quantity and term, and quality of credit.
- *Evaluation of Scoring Factors* – Next, we scored bids that meet the pre-qualification standards. Overall scores were comprised of price and non-price factors.

Independent Observer

PGE is using an independent, third-party observer to validate that our scoring criteria do not inappropriately bias the process in favor of equity investment by PGE. The independent observer has the following tasks:

- Evaluate the scoring criteria to confirm that they do not inappropriately bias the process in favor of an equity investment by PGE.
- Evaluate whether scoring criteria have been applied in a fair and unbiased manner.

- At the discretion of the independent observer, observe and review the process by which PGE evaluates and negotiates the short list proposals to confirm that the process is not inappropriately biased in favor of an equity investment by PGE.
- Submit a written report to the Commission, in light of the above, stating whether the process was fair and objective.

Selecting A Short List

Using the scoring process described above, PGE selected a short list that exceeded the resource targets stated in the RFP. Characteristics of the bids received, and the resulting short list, are described in this section. The results of current negotiations will help determine our specific resource actions.

The following tables describe key characteristics of the bids we received, and the short list selected from them.

Table 7. Fuels for RFP Energy and Capacity Proposals

	Universe of Bids[A]		*Short-list*	
	MWa	*%*	*MWa*	*%*
Natural Gas	11,238	79	665	52
Coal	452	3	90	7
Wind	884	6	112	9
Biomass	453	3	17	1
Geothermal	149	1	-	0
System, financial, other[B]	1,000	7	400	31
Total:	14,176	100	1,285	100

[A]Some bids proposed multiple fuels, *e.g.*, coal and wind.

[B]Includes two bids fueled by oil and one by petroleum coke; some "system" sales are affected by gas prices.

Of the energy products proposed from actual facilities, only 25 percent were supplied by existing plants, as shown below.

Table 8. Energy by Plant Construction Status

	Bid Universe		*Short List*	
	MWa	*%*	*MWa*	*%*
Existing	3,486	25	850	66
In Progress	2,110	15	-	-
Proposed	8,580	61	435	34
Total:	14,176	100	1,285	100

Of the 13 capacity bids we received, two did not qualify to be scored. The remainder are characterized in the following table.

Table 9. Capacity Bids

No. of Bids	*Type of Product*
3	Heat Rate Option
3	Peak Toll
2	Peak Toll – Duct Firing*
2	Seasonal Exchange
1	Virtual Toll

**Duct firing capacity options are contingent upon accepting the associated energy bid.*

Most bidders were unable to provide delivery to any of the preferred transmission points specified in the RFP, as shown below.

Table 10. Transmission Points of Delivery

Priority	*Received (%)*	*Points of Delivery*
1	5	PGE service territory
2	10	COB
3	15	NW Market/Mid-Columbia
4	5	John Day
N/A	65	Other PODs

RFP for Natural Gas Commodity and Transportation

On July 8, PGE sent an RFP to 50 potential bidders and, by our deadline of July 23, nine responded by proposing fixed price gas and transportation products. Also, eight bidders provided proposals for physical or financial gas at volumes between 5,000 and 20,000 Dth per day for up to 10 year terms, but most were in the two- to five-year timeframe. We received bids for fixed price and index physical gas and transportation, as described below.

- One proposal for interstate gas transport, partial distance from Sumas to the Kelso-Beaver (KB) pipeline on Williams Northwest Pipeline.
- Bids offered to supply gas from four NW markets – Sumas, West Coast Station 2, Rockies and AECO – plus delivered gas to the Kelso-Beaver lateral.
- Offers for physical Sumas gas were limited compared to other products, *e.g.*, financial gas and other, more liquid, hubs.
- Generally more robust bid response for financial gas than for physical gas.
- Prices varied, depending on delivery point, term and whether the bid was for a physical or a financial offer.

We used the short- and mid-term natural gas prices, coupled with long-term fundamental prices, when imputing fuel costs to score bids received in our 2003 RFP for energy and capacity products.

RFI for Demand-Response Products

On July 11, 2003, PGE issued a Request For Information (RFI) to larger non-residential customers, requesting indications of interest in providing dispatchable capacity products to meet short-term needs, and fixed-term products to fill peak hours of peak months. Selected customers with aggregated loads of at least 1 MW received the RFI.

Seven customers showed interest, but only one submitted a proposal for a 2 MW on-call product. Two other customers indicated they had reviewed the proposal in detail, but could not design a product that benefited them under the conditions of the RFQ. We followed up with about 20 non-responders to evaluate RFQ process and requirements, and customers' ability to respond. We will spend more time working with these customers to identify opportunities to develop non-residential demand response as a capacity resource.

What We Learned About the Market

Most of the bids received were supplied by projects powered by natural gas. PGE sought contracts or ownership opportunities that provide a range of commitment, from five to 10, through 20 to 30, years. However, the natural gas market for commodity and transportation operates in the near term, from two to five years out. Gas transportation is likely to continue to be an issue until more infrastructure is constructed, especially as more power plants and other industrial consumers of the commodity are brought on-line.

Transporting *power* also affected the scoring of nearly all bids received. Even though bidders knew PGE's service territory was our preferred point-of-delivery (POD), they did not acquire long-term firm transmission from BPA for their generating projects. We confirmed that, in certain cases, firm transmission to our service territory is not available through BPA's system.

Lack of inexpensive firm transmission is a particular problem for wind generation, because most wind sites are located east of the Cascades. The necessity to reserve transmission for the full capacity of a wind farm, while typically realizing only 30 to 35 percent average energy from these sites, means that the cost of wind transmission per MWh is about three times that for a thermal resource in a similar location that can operate whether or not the wind is blowing.

Bonneville has developed a wind integration service that is essential for wind developers. Under this plan, wind generation is delivered hourly to BPA, who uses it to offset its other resources. BPA returns the wind energy to PGE as a firm resource seven days later, so that the aggregated amount of wind energy captured during on-peak hours is returned to PGE seven days later as a flat amount across all on-peak hours. Similarly, the aggregated amount of wind energy captured during off-peak hours is returned to PGE seven days later as a flat amount across all off-peak hours.

If the amount of energy to be returned in any hour exceeds 50 percent of the maximum wind generation output, the amount above 50 percent will be stored by BPA and returned at the first opportunity during a similar on-peak or off-peak hour when the amount of energy does not exceed 50 percent of the maximum wind generation output. This integration service is contingent upon using BPA's transmission twice, first to wheel the wind energy from the wind generator to BPA, and again seven days later to wheel the return wind energy from BPA to PGE's service territory.

Finally, customer participation in firm, dispatchable demand-response programs may continue to be limited, making this an impractical capacity resource.

Status of Post-RFP Negotiations for Energy and Capacity

On October 21, PGE notified all bidders regarding their position on or off the short list. We have initiated negotiations with 11 counterparties regarding 17 proposals. Short-listed bids represent energy and capacity resources that significantly exceed PGE's ultimate resource requirements. Pursuing negotiations with a short-listed bid pool that exceeds our resource needs maintains the competitive nature of the resource acquisition process.

Our objective continues to be to increase value and decrease costs of selected resources through the negotiation process. As we conduct negotiations, we are also performing in-depth due diligence analysis in the areas of technical, operational, transmission, fuel source, environmental and other risk elements to ensure the integrity of resource viability and economics.

We are negotiating in parallel with third-party providers of integration, transmission, ancillary services and natural gas transportation that would be required for certain proposals. In some cases, the results of these negotiations may affect the viability and economics of the short-listed bids.

Discussions with short-listed bidders are generally proceeding as expected, and we anticipate that contracts selected for acquisition will be executed around the end of the first quarter of 2004. As we complete our negotiations and develop final contracts, we will initiate rate treatment proceedings with the OPUC as appropriate.

Update on Port Westward

As detailed in our specific energy actions above, PGE proposes to develop a new, gas-fired CCCT generation plant as a part of our 2002 resource action plan. Located at our Port Westward site adjacent to our Beaver plant, this plant would connect directly to our transmission system and use infrastructure, including a natural gas supply lateral, already in place to serve our existing facility.

This chapter covers the following topics:

- One Unit, G-Class Technology
- Advantages for Customers
- Mitigating Potential Risks

One Unit, G-Class Technology

In our 2003 RFP, we listed among our resource alternatives the possibility of developing one or two “F-class or equivalent” gas turbines at our Port Westward site (*RFP*, p. 10). We currently plan to install one unit, but reserve the option to develop both, pending the outcome of our post-RFP negotiations.

Since last June, when we issued the RFP, we have continued to evaluate the G-class turbine technology manufactured by Mitsubishi and Siemens-Westinghouse. As a result, we are considering installing a G-class machine at the Port Westward site, rather than the older F-class technology discussed in the RFP.

Our evaluation has been extensive. Besides spending considerable time with each manufacturer discussing and evaluating all aspects of their design and manufacturing criteria and worldwide operating experience, we sent a team to visit two operating G-class plants and interview plant personnel at these sites. We also retained an independent engineer to evaluate the technology against the F-class technology. We will continue to seek out information and opinions and continue our evaluation of the technology choice up to the time we must commit to a specific technology.

The G-class turbine has been in operation since 1997. Because G-class turbines provide a larger plant and newer technology, we also expect the construction time could be about three months longer than for the F-class. Due to the difference in the number of installed turbines, engineering, procurement and construction (EPC) contractors have less experience in developing the G-class plants. On the other hand, the overall construction process and scope are the same for both technologies. The primary benefits of the G-class over the F-class are the increased baseload output capability and the minimum three percent increase in fuel efficiency and base load plant heat rate.

Both technologies present benefits and risks. All turbine manufacturers have continued to make changes in their designs to address problems and to make improvements. We expect that the benefits of the increased output and better fuel efficiency will result in lower costs and prices for customers with the same or better plant reliability.

However, recognizing the relatively limited industry operating experience with the G-class, one of our key deciding factors will be the equipment warranties and guarantees, and the long-term service agreement, that we negotiate to provide reasonable protection against material cost increases or decreases in plant performance. We will select the technology and manufacturer that provides the most value in the form of least cost and highest reliability for our customers.

As summarized below, switching to G-class technology would provide significant cost benefits for our customers. Our cost figures are proprietary pending negotiations with manufacturers, but we are willing to share them with qualified parties under protective order.

Table 11. Comparison of F and G Turbine Technology

	F Technology	*G Technology*
Capacity with duct firing (MW)	309	399
Energy without duct firing (MWa)	235	347
Capacity, without duct firing (MW)	253	374
Heat Rate, no duct firing	7,090	6,863

At assumed gas market curve used for RFP price analysis.

Advantages for Customers

Developing a new generating plant provides several clear advantages for our customers. Committing to a 30-year resource eliminates the portion of price volatility that may occur when moving to another expensive resource when a shorter-term contract expires. At the same time, this long-term commitment provides a relatively low, fixed heat rate, meaning that the plant would be dispatched frequently, before most other gas-fired resources in the Pacific Northwest and in place of other, more expensive resources. These facts dampen rate volatility and lock in for the long-term what today are relatively low-cost resources, although we are still subject to fuel price volatility.

While the failure of a major piece of equipment, or a significant transmission outage, could take the plant off-line for an extended period of time, reliability of the new plant will likely be high for two key reasons. First, we will control operations and maintenance, allowing us to emphasize high reliability and to enhance the flexibility of operation by allowing us to optimize the value of the resource to reduce overall cost. Secondly, because the plant would be connected directly to PGE's transmission system, we also avoid certain reliability issues associated with longer and more congested transmission paths, and the potential risk of transmission congestion pricing.

The new plant would also take advantage of infrastructure already in place at our Beaver plant, including the K-B natural gas lateral connection to the Williams pipeline.

For these reasons, building two units at the Port Westward location scored among the highest in our 2003 RFP. Our recent experience with scoring our 2003 RFP bids confirmed the findings in our *IRP*: a 30-year commitment of a gas-fired CCCT, such as Port Westward, continues to provide the best price stability at the lowest cost for our customers (Trial Plan 8).

Currently, more than half of our resources are acquired through contracts that provide no earnings potential, are imputed by rating agencies as debt, and provide no value for customers once the contract has expired. Customers would have the opportunity to realize the full value of the project for its entire useful life, as opposed to contract resources that generally provide no additional economic value after the contract period. Adding a significant physical resource also supports company earnings, strengthening our ability to manage financial risks.

Mitigating Potential Risks

Among the portfolio trade-offs are the risk that a significant equipment failure or transmission outage could deprive us of the output of the plant for an extended period of time. As discussed above, we plan to mitigate these risks by obtaining acceptable equipment warranty and long-term service agreement terms associated with our turbine purchase, operating and maintaining the plant ourselves, and by establishing a suitable planning reserve margin.

Adding another gas-fired plant also increases PGE's exposure to natural gas commodity and transportation costs. While developing two units at Port Westward scored very high in our RFP process, we currently plan to build just one unit, filling roughly half of our energy deficit with long-term gas-fired generation. That leaves the remainder to be filled with a mix of resources that provide more portfolio diversity in terms of fuels, technology and length of commitment, while preserving long-term fuel options for another planning period. We discuss our gas strategy in greater detail in the following chapter.

Natural Gas Outlook and Strategy

To fuel the resource actions contemplated by the Proposed Action Plan, we would need to procure and manage an additional 69,000 to 99,000 Dth per day of natural gas, depending on ultimate resource selection.

We contacted industry experts and reviewed various industry sources to assist in the evaluation of natural gas market forecasts. This research focused on market views of environment, technology, industry structure, and inter-fuel competition.

One of the main sources used in performing this research was Cambridge Energy Research Associates (CERA). CERA is a leading international advisory and consulting firm that focuses on energy industry markets, geopolitics, structures and strategies. CERA's independent expertise and perspective help clients evaluate the future of energy markets to make informed strategic, investment, and market decisions.

This chapter covers the following topics:

- Natural Gas Outlook
- Supplying Natural Gas to Potential Resource Alternatives
- Gas Supply Strategy
- Conclusion

Natural Gas Outlook

PGE used CERA's *New Realities, New Risks: North American Power and Gas Scenarios Through 2020* as the basis for our evaluation of future natural gas markets. In this study, CERA outlined four scenarios that portrayed differing political, socioeconomic, and environmental influences and their possible effects on gas prices. Each scenario included different expectations as to the fundamental price drivers and the pricing results, but several consistent themes emerged:

- *Gas prices remain quite high and volatile in all scenarios* – CERA's analysis supported PGE's forecast of long-term equilibrium Pacific Northwest gas prices, $4 nominal and up.
- *Traditional supplies under severe pressure* – Domestic and Canadian gas supplies are available, and prices over $3.50 will attract non-traditional supplies, but the cost of extraction is likely high and uncertain.
- *LNG imports rise significantly by 25 percent or more per year* – LNG has an edge on Arctic gas due to smaller incremental needs for infrastructure expansion, plus room to expand shipments to existing terminals. However, significant capital investment will be required to develop LNG facilities.
- *Infrastructure investment is critical* – Major gas pipeline and storage investments are needed to distribute non-traditional supplies in optimal timeframes.

Besides CERA's work, we also extensively reviewed fundamental supply and demand drivers, such as proven reserves, storage capacity, pipeline capacity, peak day delivery, exploration and production activity, and others. The following summarizes additional insights from this research.

- *U.S. and Canadian gas storage flexibility is decreasing* – The storage "cushion" is decreasing because development is not keeping up with demand. Supply was flexed to its limits in 2002-03, although the winter was not extreme, and statistically is likely to be worse one of every six years. Less storage flexibility implies continued high price volatility.
- *Pacific NW gas demand is growing by 2.3 percent per year* – The key growth driver is gas-fired generation, 7.3 percent annually from 2003 through 2012. Growth in peaking gas resources is not cost-justifying pipeline expansions, so pipes and storage are unlikely to expand significantly in the near-term.

The result of this study and other analysis is that the market should expect continuing high prices and volatility because traditional supplies, such as Gulf gas and Canadian imports, are not expected to keep up with increasing demands for natural gas. Therefore, new sources of supply will likely be needed to meet demand and the majority of these new supplies are expected to be more expensive than traditional sources. The cost estimates of the non-traditional supply sources listed below range widely among analysts.

Table 12. Anticipated Gas Prices by Source

Resource	*Anticipated Price (nominal)*	*Notes*
Deep Gulf gas	$2.50+	Declines in traditional Gulf supply may be offset by more expensive Deep Gulf gas. Limited production increases expected.
Rockies coal-bed methane	$2.80 to $3.20	100+ TCF* recoverable, but subject to significant environmental restrictions limiting drilling, slowing supply increases.
LNG imports	$3.50 to $4.00	Likely supply-demand "balancer." West Coast appears likely to add a LNG terminal based on recent commitments to 20-year supply by big oil companies.
Additional Canadian imports	$4.00	All CERA scenarios expect increasing imports, but unlikely to "solve" North America supply needs.
Arctic gas	$4.00 to $4.75	Pipeline would cost $10 to $20 billion; sustained high gas prices needed to justify cost. On-stream in 2009 or later.

**TCF: Trillion cubic feet.*

Sources: CERA, EIA, AGA, Lookout Mountain Analysis, Entergy-Koch, Marathon Oil.

Supplying Natural Gas to Potential Resource Alternatives

Ensuring reliable energy resources at a reasonable price requires active risk management of our natural gas portfolio. Two of the main types of risks associated with natural gas procurement are price volatility and gas transportation. Price volatility reflects the unpredictable movements in the price of the commodity, while gas transportation risk challenges the reliability of supply access and deliverability. The following discussion outlines our strategies for managing these risks.

Gas Transportation

The goal of managing natural gas transportation is to make available on a firm basis an adequate supply of natural gas to a generation station to allow for the dispatch of the plant when it is the least incremental cost resource, and to liquidate these transportation assets when other lower cost resources are available. PGE currently manages 76,000 Dth per day of transport on the Williams NW Pipeline system (NW Pipe) to supply its Beaver generating plant and 41,000 Dth per day of transport on the National Energy GTN system for its Coyote Springs 1 generating plant.

In assessing the cost of gas transportation for various resource alternatives, we received indicative expansion pricing on the NW Pipe system, along with indicative prices for released evergreen capacity from existing NW Pipe shippers. Existing NW Pipe shippers have informally offered released capacity to PGE at rates lower than expansion rates, but the secondary market for evergreen capacity rights is limited and subject to increased competition.

Given this limitation on the availability of released evergreen capacity, we are considering acquiring this secondary market capacity as soon as possible. However, if this commitment is made currently, and in connection with the development of the Port Westward plant, it is likely that we will be required to take title to the capacity immediately although Port Westward will not be online until 2006. This may result in 30 months of additional gross gas transportation expenses being allocated to Port Westward net of any secondary short-term capacity release revenues that might obtain.

Spread over the 30-year depreciable life of the plant, the net cost per year remains smaller than the annual cost associated with pipeline expansion. Furthermore, NW Pipe has indicated that a pipeline expansion may delay the desired online date of Port Westward, because expansion would likely require at least 27 months due to permitting and environmental restrictions on construction.

Proposed Gas Transportation Actions

We plan to acquire additional gas transportation for the full capacity of the Port Westward plant currently to take advantage of evergreen capacity release pricing. As mentioned above, this saves the price differential between expansion capacity and released capacity while ensuring that capacity is available upon commercial operations of the plant. For gas transportation requirements associated with other potential short-listed resources that require PGE to supply gas, we plan to execute transport commitments simultaneously with the execution of the respective energy or capacity purchase agreements.

Gas Supply Strategy

As discussed above under "Natural Gas Outlook," the forward forecast for natural gas indicates supply availability but with continued price volatility. PGE's existing natural gas fired resources require approximately 159,000 Dth per day of gas at full dispatch and is managed daily to capture the value of the plant heat rates as compared to the market clearing price for electricity. We are one of the largest consumers of natural gas in the Northwest and have managed a portfolio of this size for over eight years. Adding a Port Westward type plant or gas tolling resource to our portfolio would increase these volumes by approximately 69,000 Dth to 99,000 Dth per day.

In managing the price risk associated with these gas volumes, we use our access to the physical and financial gas markets to hedge and limit our exposure to price volatility. We will use such market instruments as forwards, swaps, options and futures contracts to accomplish this goal. These instruments are executed for varying periods and are subject to counterparty-to-counterparty credit limitations.

To determine the volume of our gas requirement to hedge on a forward basis, we segment the market into three time frames and assess the pros and cons of each tenor (contract length). A summary of these tenors and their characteristics are listed in the following table.

Table 13. Natural Gas Pros and Cons by Tenor

Tenor	*Pros*	*Cons*
Long-term (10+ years)	▪ Price certainty. ▪ Supply certainty.	▪ Premium over fundamental forecast prices. ▪ Working capital requirements. ▪ Lack of liquidity.
Medium-term (3-9 years)	▪ Price certainty. ▪ Supply certainty. ▪ Lower premiums than long-term.	▪ Premium over fundamental forecast prices. ▪ Reduced liquidity.
Short-term (<3 years)	▪ Liquid market – NYMEX actively traded in this period. ▪ More flexibility.	▪ High price volatility; higher earnings volatility. ▪ No long-term supply certainty.

Ultimately, a combination of contract durations is likely to result in the best overall mitigation of volatility while limiting the premium paid to "lock in" the price of gas. Also, multiple contact durations will help to minimize the cost of credit performance assurance. For example, a 10-year purchase agreement for 10,000 Dth per day could expose the purchaser to a credit performance assurance call of $9.1 million if the market moved against this contract by $0.25 per Dth for its entire term. Multiples of the $9.1 million call would be incurred on price movements greater than $0.25 per Dth.

Beaver Plant

As an intermediate-duty plant, Beaver's gas needs depend on the interaction of gas and power prices. During 2003, due to high gas prices and the addition of new, efficient baseload plants to the market, Beaver's heat rate remained above the market clearing heat rate more than 75 percent of the time, idling the plant during those periods. Our analysis indicated that Beaver will be economic approximately 45 percent of available hours in future years. As a result, acquiring long-term baseload supply is not ideal for managing Beaver's fuel requirements as compared to the flexibility of short-term markets. By acquiring Beaver's fuel in the short-term market, we can dispatch the plant only when the economics of doing so would produce a positive margin or provide for system reliability. Our procurement strategy for Beaver includes the following considerations:

- Entering into financial instruments that swap out indexed short-term price exposure for fixed prices in advance of each annual regulatory power cost filing or Resource Valuation Mechanism (RVM), shaped by expected monthly plant dispatch.
- Acquiring physical supplies secured at index in the month-ahead markets.
- If supply is of concern, acquiring physical gas up to two years in advance.

Coyote Springs 1 , Port Westward and RFP Resource Alternatives

If the Port Westward plant is added to PGE's gas supply portfolio, the portfolio would include two low heat rate baseload plants, Port Westward and Coyote Springs 1. We plan to purchase sufficient gas to support operation of these two plants at 80 percent capacity factors. We will then purchase gas in the spot market during times when it is economically advantageous to operate plants more, and sell gas into the spot market during times when it is economically advantageous to operate the plants less.

To manage the supply risk associated with our existing baseload plant and evaluate market alternatives, we issued an RFP for long-term natural gas concurrently with our 2003 RFP for energy and capacity resources. Of the 50 counterparties that received the Gas RFP, only 20 percent responded, providing pricing for various Pacific Northwest locations for sales up to 10 years long. These results were incorporated into the long-term gas forecast prices used to evaluate gas-fired bids received in response to our RFP for energy and capacity. As discussed above in "Requests for Proposals – Electricity, Capacity, Gas," we gained several insights from the gas RFP:

- No producers and few counterparties were interested in providing long-term offers.
- Many indicated that the working capital requirements, credit exposure, and Value At Risk (VAR) associated with long-term deals made offers greater than 10 years unfeasible.

- A majority of the responses that were received were for financial, rather than physical, gas.
- Average 10-year prices were $4.18 at AECO and $4.50 at Sumas.

Because of the lack of liquidity in longer-term gas markets, and the price premiums and credit requirements needed to lock in long-term fixed gas prices, we do not plan to hedge any portion of our baseload gas requirement in the longer-term markets. Instead, we plan to diversify our gas supply by medium and short-term tenor, layering in our purchases and utilizing market storage. Of the anticipated 88,000 Dth per day expected average gas requirement for Coyote Springs 1 and Port Westward, we would target layering in gas procurement for the tenors shown in the following table.

Table 14. Tenor Diversification of Baseload Gas Supply

Tenor	*Avg. Daily Demand (Dth), based on Est. Capacity Factor*	*Ratio (%)*
Medium-term (3 to <10 years)	40,000	45
Short-term (<3 years)	48,000	55

Applies to Coyote Springs 1 and Port Westward.

This approach allows for diversification of price risk away from short-term adverse price movements by layering purchases with longer durations into our portfolio. A mix of medium and short-term contracts also allows us to stagger the expiration dates of contracts, so renegotiations do not all occur at one time. This will reduce the likelihood that we will have to renegotiate significant quantities of gas supply during an aberrant price spike, as we observed in 2000-01. Our plan calls for a mix of contract durations, *i.e.*, some five-year, some 3-year, *etc.*, allowing flexibility to buy or sell additional supply in this ever-changing market.

By adding market storage capacity to this strategy, we will be able to procure and store gas during times of lower market prices and avoid extreme short-term market volatility. Storage also increases reliability by providing a diversification of supply points, so that price spikes in isolated markets have a smaller impact on the cost of our power supply. Furthermore, storage is available after gas markets are closed, allowing flexibility to react to significant intra-day power price or demand increases.

Execution of this strategy depends on the following circumstances:

- Regulatory review and Commission acknowledgement.
- Availability and pricing of market storage.
- Relaxed credit margining requirements, resulting from counterparty negotiations.
- Liquidity of mid-term markets.

- Counterparty credit limits.

Other strategic considerations include:

- *Supply point diversity* – Pipeline assets allow supply from multiple points of delivery.
- *Credit* – Establishing diversity of counterparties so we can diversify credit exposure.

Conclusion

Many analysts, including CERA, agree that gas prices are likely to remain high and volatile but that the supply will be available. We plan to acquire a mix of market storage and transportation to mitigate price volatility and ensure firm, reliable service to existing and new gas-fired projects. We will procure gas supply for existing and proposed baseload plants, *i.e.*, Coyote Springs 1 and Port Westward, if developed, and tolling generation in a combination of the short-term and medium-term markets.

The fuel requirements for intermediate-duty resources, such as fueling our Beaver plant and any tolling agreements, is best managed in the short-term markets. Implementing these recommendations depend on several crucial factors, such as being able to obtain released capacity while it is available, successful negotiation of a gas storage agreement, Commission approval of medium-term gas contracts, and relaxed credit margining requirements. Expedient resolution of these issues is critical to the success of this strategy.

Portfolio Analysis

This chapter describes our portfolio analysis, which evaluates our existing long-term resources in conjunction with various trial plan portfolios of new resources, including our short-listed RFP bids and self-build options at our Port Westward site. Topics include:

- Description of Stochastic Modeling
- Bookends Analysis
- Portfolio Analysis
- Gas and Other Risk Exposures
- Conclusions

Within the context of our existing, well-diversified supplies, portfolios formed from the short-listed bids received through our 2003 RFP fall within four "performance" zones. Three of these zones are fairly close in price and none yields a clear price risk reduction. Key considerations of resource diversity and non-price factors do not lend themselves well to optimization modeling.

Description of Stochastic Modeling

To model portfolios of short-listed resources we used the Transition Cost Model (TCM) that provided the analytical basis for our *IRP* and *Supplement*. We replaced the quasi-stochastic electricity price with true stochastic pricing for electricity and natural gas. We measured the performance of each portfolio by running 100 iterations of electricity and natural gas prices, and averaging the effect on the average cost for customers (Net Present Value of Revenue Requirements or NPVRR). We calculated price risks using the Rate Variability Index (RVI) of our *IRP*; the higher the RVI, the riskier the portfolio.

The following table compares parameters of the deterministic inputs (point estimates) with the stochastic input parameters of the 100 iterations performed.

Table 15. Comparison of Price Parameters for Stochastic Modeling

	Mid-C Electricity (2003 mills/kWh))		*Sumas Gas 2003 ($/MMBtu)*	
	Point	*Stochastic*	*Point*	*Stochastic*
Mean Price	43.2	43.3	3.6	3.6
Standard Deviation	7.8	34.1	0.5	1.6
Volatility Increase		437%		320%

In our model, the long-term mean of the stochastic prices equaled the long-term mean of the deterministic prices. As shown in Table 15, even our point estimate or deterministic result displays some price volatility. This is due to normal seasonality of prices plus the annual changes based on inflation and other factors. Assuming a CCCT with a heat rate of 7,000 Btu/kWh-HHV, one standard deviation of gas price change would change the cost of electricity by 11 mills. For a plant with a heat rate of 10,000 Btu/kWh-HHV, the cost of electricity would change by 16 mills. If the electricity price were fully correlated to the change in gas price, gas would account for between one-third and one-half of electric price volatility.

However, based on the historical statistical analysis, the electricity price also has about a 75 percent correlation to gas prices over time. In total, only 25 to 37 percent of the variance in electric market prices is tied to changes in gas prices.[5] This further assumes that all daily power is fueled by daily spot natural gas. We intend to acquire most of our supply in blocks well in advance of our need, further reducing volatility beyond what we have modeled. *That means the gas price volatility in the results shown below is likely to be materially overstated.*

A final relationship to note is that, based on the historical statistical analysis, electricity prices in the current month have an 80 percent correlation to the electric price from the prior month. The practical effect of this relationship is that the cyclical behavior of prices is maintained.

Appendix 3 illustrates the deterministic gas and electric prices that we assumed, and provides an example from one random stochastic draw on electric and gas prices. The distributions, auto-correlations, and cross-correlations of gas and electric prices were developed based on daily historical analysis and statistical “best fit” from daily data covering 1995 to 2001.

Bookends Analysis

To validate results of the more finely-tuned differences among our trial portfolios constructed from short-listed bids, we performed a “bookends” analysis that involved constructing hypothetical incremental supply portfolios composed entirely of a given resource type. The hypothetical portfolios included a “do nothing” base, which relies entirely on 650 MWa of new market purchases, 650 MWa of CCCT generation, either owned or tolling, 650 MWa of coal, and 650 MWa (2,150 MW constructed capacity) of new wind. These portfolios assume that transmission, fuel, and similar real-world constraints do not exist and are priced based on RFP bids for these technologies, as though they could be scaled up. The objective was to see how expected costs and cost volatility varied among these basic alternatives.

While electric market and gas prices were treated probabilistically within our modeling, as described above, coal and wind were not. Instead, these fuels were handled as fixed price commitments for modeling purposes. Coal is modeled based on our Boardman plant, and has a higher fuel cost compared to mine-mouth coal, but lower variable transmission charges. This causes coal to economically dispatch. For pricing coal, we included a basic scenario without a CO_2 tax and another assuming a \$10 per ton carbon tax.

[5] Percentages calculated as: 75% X 33%.

Production from wind was treated as though it is known and fixed. In reality, wind supply is highly variable and, in quantity, must further be backed by dispatchable gas generation, with its volatile gas price.

We used the stochastic gas and electric prices discussed above in conducting this analysis. The results of this "bookends" analysis are presented below.

Table 16. Bookends Analysis, All Portfolios Acquire 650 MWa

	100% Market	*100% Pt. Westward G*	*Coal, no CO_2 tax*	*Coal, \$10/ton CO_2 tax*	*100% Wind*
Expected NPVRR (\$000,000)	\$7,943	\$7,315	\$7,395	\$7,835	\$8,004
Expected RVI	101%	41%	21%	24%	27%
95% Confidence Interval of RVI	172%	64%	36%	37%	41%

In the long run, relying on the market may be more costly, and is certainly much more volatile than any of the longer-term supply alternatives. CCCT generation is much less volatile, because the volatility is limited to the lesser movement of gas prices compared to electric prices. Coal has a slightly higher expected price compared to gas, assuming no CO_2 tax, and a substantially higher price including the tax. However, price volatility is further materially reduced. Finally, wind is materially more costly on an expected basis compared to gas and coal, and, perhaps surprisingly, does not reduce price volatility compared to coal. This is because they are both treated as fixed price supplies.

Adding the probabilistic nature of wind supply would make this resource more volatile than coal, and would make it look more like natural gas. Compared to gas, wind is more costly on an expected basis because of higher transmission and integration costs, and because gas is dispatchable and can be switched off to take advantage of lower market prices.

Each basic supply alternative has its own unique set of benefits and risks. No one technology or fuel has a clear advantage in terms of both expected price and price volatility. Indeed, the results are clustered, which is not surprising given the competitive markets of supply, demand, and fuel substitution. The analysis supports the conclusion that the best portfolio is one that is diversified.

Portfolio Analysis

We constructed 24 different portfolio combinations plus a "do nothing" case as defined in Appendix 4. All portfolios met the criteria described above for diversification of fuels and technologies, and each has two or more of the bids short-listed in our RFP process. All portfolios included at least 27 MWa (75 MW) of wind. Some included fixed price contracts or gas tolling. Some portfolios did not contain the proposed Port Westward plant, while others included one F-class unit. Still others included two F-class units. Finally, we included a few portfolios using one G-class unit. All portfolios contained a mixture of 5-, 10-, 20-, and 30-year deals.

Figure 7, below shows the results of these 25 portfolios, in terms of expected cost and price volatility. This analysis extends through 2035, so the results represent the life-cycle economics for our 30-year proposals. For five to 20 year deals, we assume that the power is replaced. That is, when a bid expired before the 30-year horizon of our analysis, we replaced it with a generic gas tolling agreement.[6]

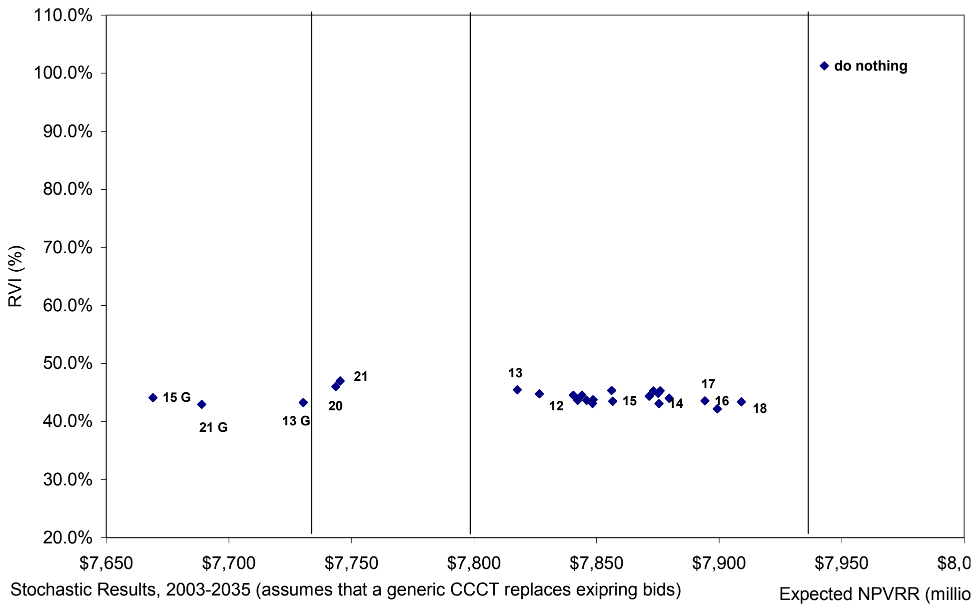

Figure 7. Stochastic Results of Portfolio Modeling

The horizontal axis of Figure 7 measures the expected cost of the portfolios, *i.e.*, the long-term NPVRR. The vertical axis shows the RVI as a measure of the worst annual rate change in the timeframe analyzed.[7] The closer a portfolio is to the origin, the lower its cost and risk. Results fell into four zones, as described below.

- *Do Nothing.* First, in a zone clearly distinct from the others, was the "do nothing" case that relied entirely on market purchases. This case was clearly the most expensive on an expected cost basis, and more volatile, since the

[6] We adopted this simplifying assumption to smooth the artificial exposure to market risk of portfolios with a higher percentage of short-term bids. In our model, unless specified otherwise, load is met with electricity market purchases. When a resource expires, it is replaced by default with spot purchases, hypothetically exposing customers to the full volatility of market prices. This modeling approach may or may not prove to be realistic and, in that it favors long-term commitments, could be viewed as biased. Therefore, we ran our portfolios with the default spot replacement assumption, and again with the assumption of a tolling agreement replacement. The NPVRR did not materially differ between these approaches.

[7] See our 2002 IRP, p. 186, for a detailed explanation of evaluating price stability for our customers.

entire incremental portfolio relied on the comparatively highly volatile electric spot market.

- *No or One F-Class Unit at Port Westward.* The next zone captured the majority of our portfolios – those that did not develop a new Port Westward plant, or that developed only one unit at that site. These were both less costly and less volatile that the "do nothing" group.
- *Two F-Class Units at Port Westward.* Developing two F-class units at Port Westward is the highest scoring option remaining in our RFP process, so the next zone, which contains trial portfolios with two F-class units, was still less expensive.
- *One G-Class Unit at Port Westward*. The final zone included developing one unit at our Port Westward site using a G-class turbine. Because G-class technology is still lower in cost than using an F-class turbine, portfolios with this technology proved to be less expensive, all else being roughly equal, on a cost per kWh basis.

  However, the portfolios with a G-class Port Westward turbine are similar in price risk to those with no Port Westward project, or with one F-class turbine at the site. Our modeling indicates that, while it is possible to construct portfolios that probabilistically yield a lower expected cost than other portfolios, little reduction in price volatility risk can actually be achieved.

Gas and Other Risk Exposures

A significant element of our Action Plan is the development of a CCCT at our Port Westward site. This would materially change our gas specific, and combined gas and electric, price risk exposure. Adding a CCCT would increase our gas-specific risk exposure. However, this must be considered in the context of our existing deficit position. Adding a portfolio of resources that included a CCCT would bring us roughly into energy load-resource balance. From the combined gas and electric price risk perspective, adding a CCCT and other resources would decrease our overall exposure.

If we made our proposed plant upgrades and considered the Confederated Tribes contract extension but made no RFP-related resource acquisitions, by 2007 we would have an energy deficit of more than 500 MWa.

Our modeling indicates that, in these circumstances, if gas prices increased by 25 percent,[8] but electric prices did not increase, our annual power costs would increase by approximately $30 million. This is largely due to increased fuel costs for our existing Coyote Springs 1 and Beaver plants, although our modeling also notes that these units would dispatch less, and power purchases would increase. If electricity prices also increased by $7 per MWh, power costs would increase by an additional approximately $54 million, or $84 million in all. This large increase is due to the increased cost of market electricity purchases to fill the energy deficit of more than 500 MWa.

[8] $1.00 per MMBtu if base gas price is $4.00.

If we acquired a portfolio of somewhat more than 500 MWa of energy resources, including an approximately 300 MW (with duct firing) F-class unit at Port Westward, our gas-specific, and potential combined gas and electric, risk exposures would be $43 million and $63 million respectively. Acquiring this portfolio, rather than taking no action, would increase our annual measure of gas specific risk by $13 million – from $30 to $43 million – as high gas prices would increase the fuel costs of the F-class unit as well as those of our existing gas-fired plants.

However, if electric prices also increased, our annual measure of risk would increase by only an additional $20 million, to $63 million. By this measure, acquisition of a portfolio that included an F-class unit would decrease annual risk exposure by $21 million, from $84 million to $63 million. This is largely due to being in energy load-resource balance, rather than having a deficit of more than 500 MWa.

If, instead, we acquired a portfolio of approximately 600 MWa of energy resources, including an approximately 400 MW (with duct firing) G-class unit at Port Westward, our gas specific, and potential combined gas and electric, risk exposures would be $48 million and $61 million respectively. Acquiring this portfolio, rather than taking no action, would increase our annual measure of gas specific risk by $18 million, from $30 to $48 million, as high gas prices would also increase the fuel costs of the G-class unit.

However, if electric prices also increased, our annual measure of risk would increase by only an additional $13 million, to $61 million. Acquiring a portfolio that included a G-class unit would decrease our measure of annual exposure to combined gas and electric price risk by $23 million, from $84 million to $61 million. This is largely due to having an approximately 70 MWa long energy position, rather than an energy deficit of more than 500 MWa. With expected load growth, this moderate long position would turn to approximate balance in 2008. So, while our Action Plan does entail an increase in gas-specific risk exposure, it significantly decreases overall exposure to combined gas and electric risk.

The following table summarizes our measures of expected gas and combined gas and electric price risks for various energy resource strategies – taking no actions, or adding resource portfolios, including either an F or G class CCCT at Port Westward – that would bring us into rough energy load-resource balance.

Table 17. Power Cost Deltas From Base Gas and Electric ($000,000)

	Do Nothing	*Add Portfolio With PW F*	*Add Portfolio With PW G*
High gas, base electric	30	43	48
High gas, high electric (+7)	84	63	61

The table summarizes the two principal conclusions of this section. First, our Proposed Action Plan calls for the addition of a portfolio including either an F- or G-class CCCT. The first row of the table indicates that this will increase gas specific risk exposure. Fuel costs could increase for more gas-fired units.

However, gas price movements do not occur in isolation. When we consider the combined gas and electric price exposures, it is clear that our recommendation to achieve rough energy load-resource balance by adding a portfolio of resources that includes either an F- or G-class CCCT decreases risk. The second row of the table illustrates this conclusion.

Conclusions

All trial portfolios are closely clustered in terms of price risk, while expected costs reflect the pricing of their dominant new resources. It is not adequate solely to consider expected price and volatility of price. A host of diversity and non-price considerations must be taken into account. For instance, if we could construct a portfolio composed entirely of fixed-price bids, it would clearly minimize incremental price volatility, but at the cost of fixed price exposure which could subsequently prove to be more expensive than short-term purchases.

Our Proposed Action Plan acquires some long-term CCCT production, the output from at least one wind proposal, and a mix of five- and 10-year fixed and variable-priced bids. This selection will provide diversity, while acquiring proposals that scored best and are expected to be least cost. After acquiring new long-term resources, we will make an economic and risk assessment of our remaining resource needs, evaluating the remaining bids that are available to us.

Appendix 1 – Load-Resource Balance Details

	Annual Average Energy MWa	*January Peak Capacity MW*
Plants		
Boardman	314	362
Colstrip	263	296
Beaver	398	500
Coyote	207	245
Oak Grove	27	42
North Fork	27	40
Faraday	23	32
River Mill	13	18
Bull Run	0	0
Sullivan	9	14
Round Butte	77	220
Pelton	32	73
Total Plants	1,391	1,842
Contracts		
Wells	94	137
Rocky Reach	87	136
Wanapum/Grant PUD Settlement	140	205
Priest Rapids	0	0
Canadian Entitlement Ext.	-16	-27
Portland Hydro	10	20
Vansycle Ridge	8	8
WWP Capacity	0	150
EWEB Capacity	0	10
Ogden Martin	9	16
Glendale Long-Term Sale	-20	-20
Glendale Exchange	0	30
Chelan Exchange In	7	0
Chelan Exchange Out	-8	0
Wells Settlement Agrmnt.	11	11
Tribes	0	0
Cove Replacement	-1	-1
BPA Subscr. Power / Other	1	3
Total Contracts	323	678
Total Existing Resources	1,714	2,520
Additional Resources Required for Critical Hydro Adjustment	-	-
Total Resources with Critical Hydro Adjustment	**1,714**	**2,520**
Total Load	2,484	3,952
Customers Leaving COS (5-yrs opt-out)	(10)	(11)
12% Reserve Margin in IRP		470
Total COS Load	**2,474**	**4,411**
Resources Gap	**760**	**1,890**

*Numbers may not foot due to rounding.

Table 18. 2007 Load-Resource Balance Details

Appendix 2 – Comparison of Utility Planning Reserves

Table 19. Survey of Utility Planning Reserves

Planning Targets

	Energy	Capacity (reserves include operating reserve margins)	Source
Avista - 2000 IRP	Generation capability under critical water conditions	15% of 1-in-2 peak load	2000 IRP, Appendix C, page 5
BPA	Generation capability under critical water conditions	15% for thermal resources, 5% for other	2002 Final Power Rate proposal. Loads and Resources Study. WP-02-FS-BPA-01. May 2000. Pages 20, 24.
Idaho Power	1-in-3 load (or 70th percentile) 1-in-3 water (or 70th percentile)	1-in-3 peak, 1-in-10 stream flow	2002 IRP, June 2002. Page 49.
NWPPC/WECC	No planning standard is set. WECC stipulates that participants report generation under "adverse hydro" but does not define it.	No universal reliability standard. WECC sets a MINIMUM operating reserve margin of 5% of hydro and 7% of thermal resources. WECC does not set planning criteria.	January 27, 2003 Resource Adequacy Forum. Meeting Report. Page 1. "Reliability Standards for the NW Power System, October 10, 2001. Pages 1, 10.
PacifiCorp	Generation capability under average water conditions	15% of 1-in-2 peak load	2002 IRP, October 2002. Page 145.
PGE - 2002 IRP	Generation capability under critical water conditions	12% of 1-in-2 peak load (with a "go short" strategy of 500MW)	2002 IRP Supplement. Pages 45, 83.
Puget	Economic generation under average water conditions	Traditionally used: 1-in-2 peak load+ operating reserve (5% for hydro, 7% for other)+required regulatory margin (not specified) Adopted in 2002: unclear in draft IRP. Probably something between 1-in-2 and 1-in-20 peak + reserves as above	Draft 2002-03 Least Cost Plan. Filed on Dec. 30, 2002. Chapter 8, pages 7, 11.

PGE's historical approach

	Energy planning standard	Capacity (reserves include operating reserve margins)
1992 IRP	Critical water	15% declining to 10%
1995-97 IRP	Short-term market purchases cheaper then long-term investment: short position is least cost. WSCC surplus makes it easy to "buy reserves" at low cost short-term	6% of 1-in-2 peak load
2000 IRP	Average vs. critical water is an open issue Used average water	6% of 1-in-2 peak load
2002 IRP:		
- August 2002	Average Water	6% of 1-in-2 peak load Capacity target: 500 MW short of peak load (1-in-2 peak + 6%)
- February 2003	Critical water	12% of 1-in-2 peak load Capacity target: 500 MW short of peak load (1-in-2 peak + 12%)

Studies/proposals for capacity planning reserves

FERC, 2002: "Ensuring Adequate Capacity Reserves"
Historical range in regulated monopolies: 15- 20% (national).

FERC: Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Design, Docket No. RM01-12-000, para 492-493.
Proposed a minimium of a 12 percent reserve margin as a fallback provision if the Regional State Advisory Committee does not reach agreement on the appropriate level of resource adequacy.
FERC noted that 12 percent is low by traditional generation adequacy standards and that most utilities historically used a reserve margin well above 12 percent.

CAISO, 2001: Preliminary Study of Reserve Margin Requirements Necessary to Promote Workable Competition
Suggested range: 14% to 19% of the annual peak load (to be reached with a mix of DSM, conservation, long-term contracts, new generation)

State of California, 2002: Establishment of a Target Reserve level for the California Power Authority Investment Plan
Proposed a 15% target.

California Power Authority, 2003, Rulemaking: Establishment of Target Reserve Level for the California Power Authority Investment Plan Docket 2002-07-01
No less than 17% of the projected monthly peak load (strongly encouraged DSM for at least 25% of it).
17% is just a starting value. Regulators will adjust it up or down.

NWPPC - Power Supply Adequacy Forum, 2003
Planning to meet to discuss resource adequacy issues.

Appendix 3 – Price Forecast and Stochastic Modeling

We updated PGE's forecast of natural gas and electricity prices, as recommended by OPUC Staff in their March 21, 2003 comments to our 2002 *IRP*. For gas, we changed our forecasting methodology and relied on the following items:

- Response to our 2002 natural gas RFP, for years 2003 to 2009.
- NWPCC forecast after 2009.[9]

The charts below show the effect on prices of such update: AECO and SUMAS hub prices are substantially higher than what we assumed in our *Supplement* for the years 2005-10, and five to seven percent lower after 2011.

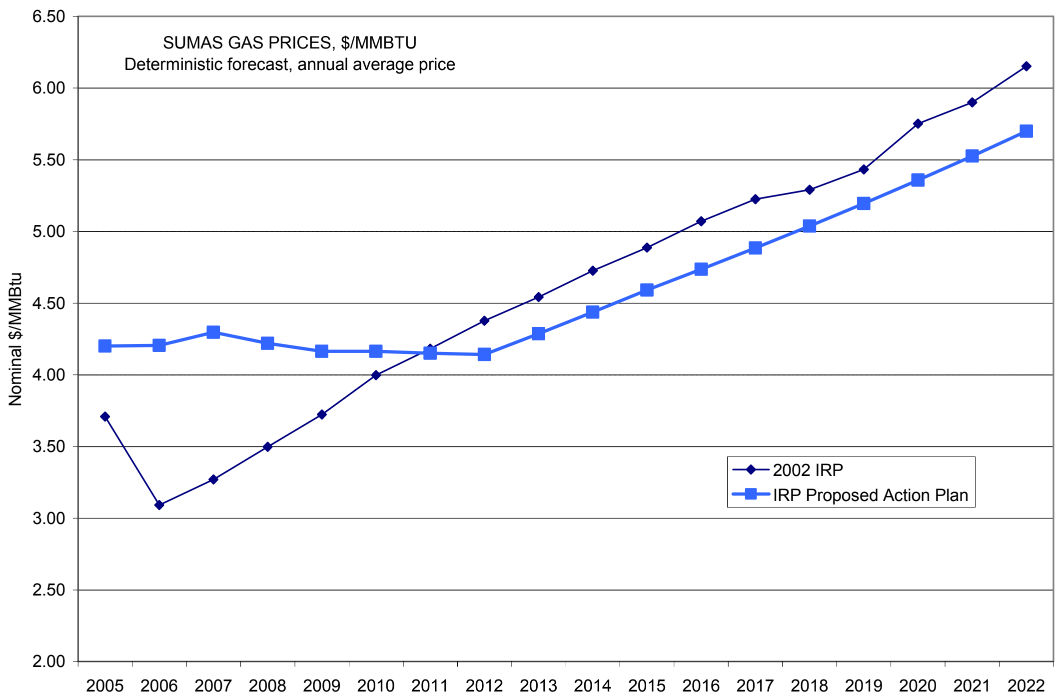

Figure 8. Natural Gas Price Forecasts (Sumas)

[9] Northwest Power and Conservation Council, *Fuel Price Forecasts for the Draft Fifth Northwest Conservation and Electric Power Plan*, April 22, 2003.

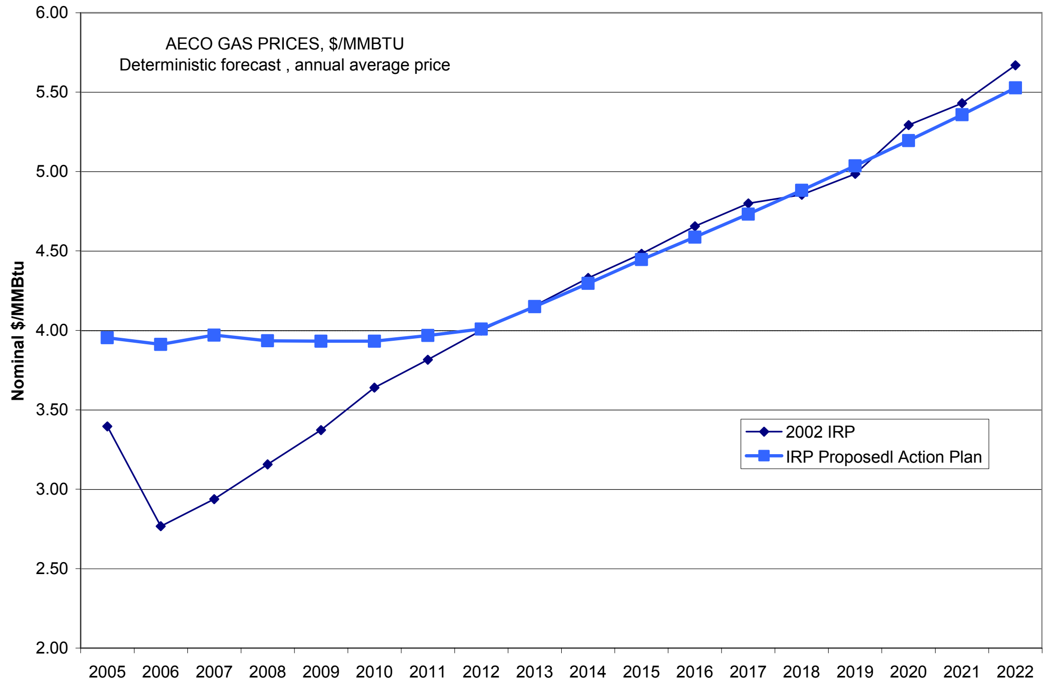

Figure 9. Natural Gas Price Forecasts (AECO)

We used the gas forecast described above to develop projected annual average electricity prices at the Mid-Columbia hub. We used a CCCT as the incremental unit setting long-term electricity prices in the Northwest (S*upplement*, p. 61), and used its fully-allocated cost for 2007 through 2022. After 2022, prices grow with inflation. Electricity prices before 2007 match the forward curve.

The figure below compares the expected flat annual prices for Mid-Columbia used in the *Supplement* with those used for this Action Plan. The updated prices at the Mid-Columbia hub are expected to be higher for 2007-11 because of higher forecasts for gas prices. Starting in 2012, however, the long-term price for electricity is not significantly different from what was projected in the *Supplement*. Higher gas and electricity prices for the 2007-11 period increase the cost of gas-fueled resources and power purchases indexed to market. Nonetheless, new CCCT generation remains economic over its book life.

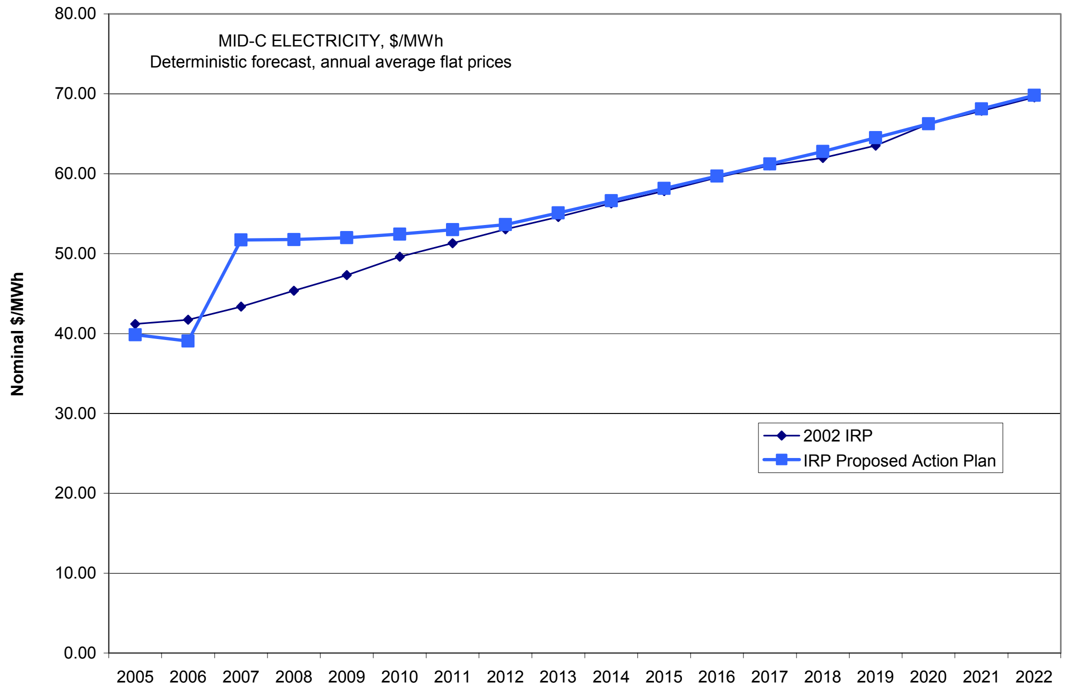

Figure 10. Electricity Price Forecast (Mid-Columbia)

Once we developed the deterministic forecast of gas and electricity prices, we computed monthly averages using monthly shaping factors. We then analyzed potential volatility for those monthly averages based on the historical behavior of prices. We calculated monthly volatility factors and used them to induce volatility for the monthly deterministic prices of electricity and natural gas. We assumed that electricity prices will continue to be capped at $250 per MWh (real). We did not assume a price cap for gas.

The characteristics of our stochastic model include:

- The average of the stochastic prices equals the deterministic prices for electricity and gas.
- Natural gas is substantially less volatile than electricity, contributing about one-third of the electric market volatility.
- Gas is about 75 percent correlated to electricity.
- Electricity is about 80 percent correlated to itself from month to month.
- Even with deterministic pricing, seasonal and annual volatility exists, but is relatively small.

Figures 11 and 12, below, show the difference between deterministic prices and one of the 100 simulations used for the stochastic analysis.

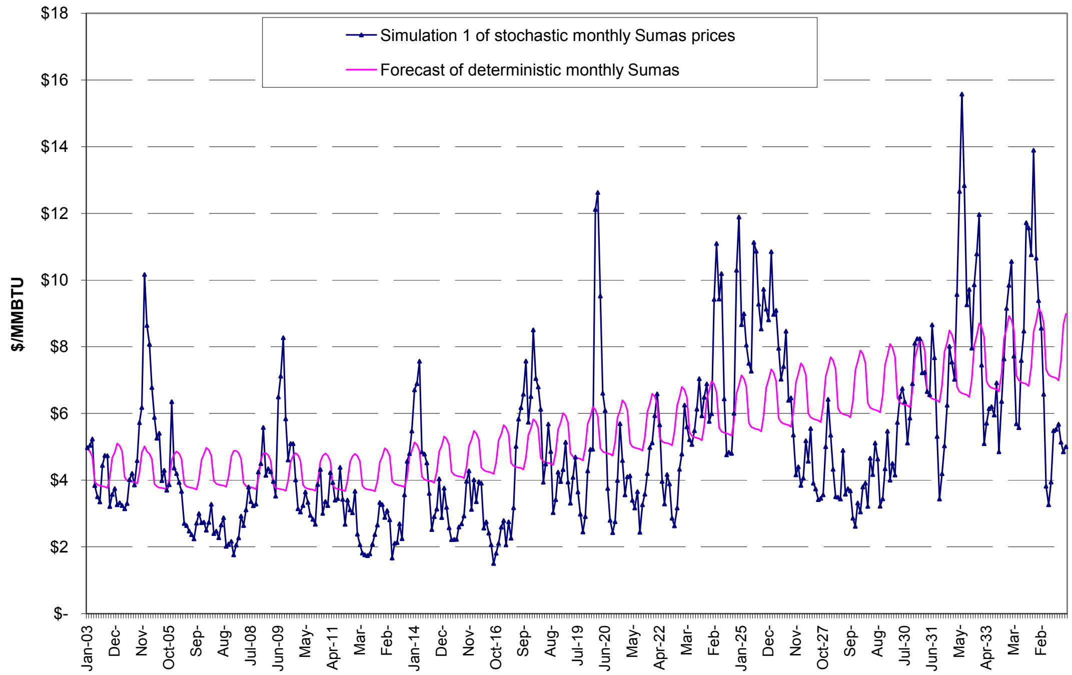

Figure 11. Comparison of Monthly Gas Prices (nominal $)

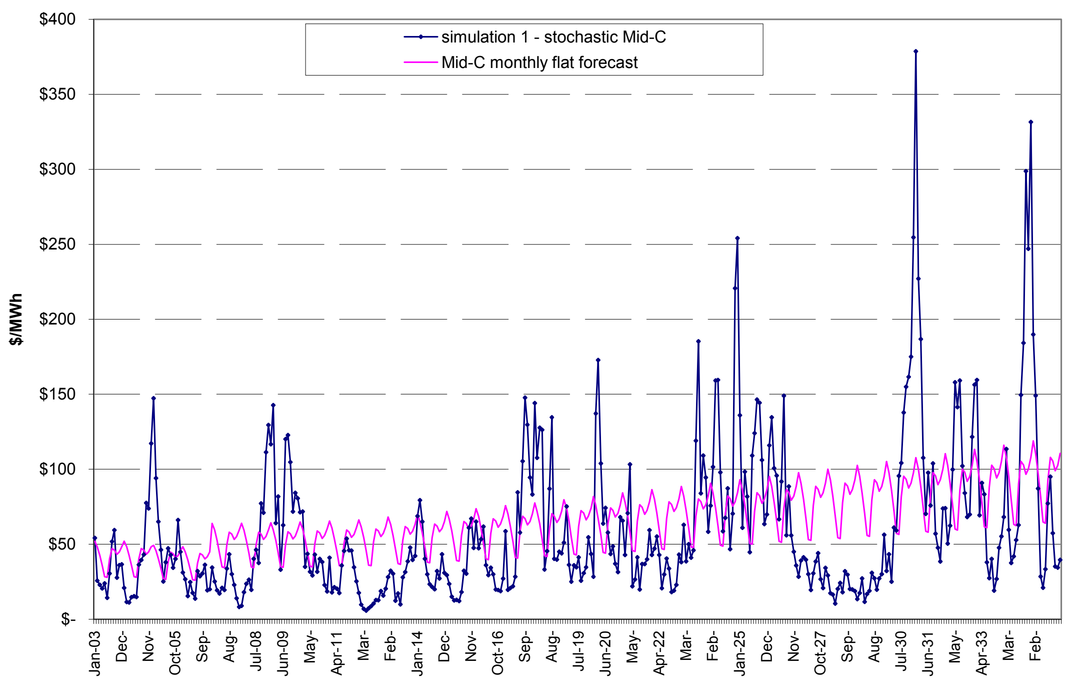

Figure 12. Comparison of Mid-Columbia Monthly Flat Prices (nominal $)

Appendix 4 – Composition of Trial Portfolios

Table 20. Composition of Trial Portfolios

PORTFOLIO ANALYSIS - DETAIL OF LONG-TERM RESOURCES ADDED TO PGE'S EXISTING MIX

Mix of New Long-term Resources (MWa in 2007) *		Portfolio No. 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	13 G	15 G	21 G
Resources	Typical Term																									
Renewables	20 yrs.	27	64	27	27	27	64	27	64	27	64	64	64	27	64	27	27	89	27	89	27	64	-	89	27	64
Gas Tolling	5-20 yrs.	203	203	243	188	236	201	138	118	118	118	98	118	108	341	286	426	361	366	78	-	-	-	118	70	83
Fixed price PPAs	5-20 yrs	50	50	50	50	50	50	152	152	152	127	152	-	50	50	135	135	135	127	152	-	-	-	50	135	85
Port Westward F or similar	30 yrs.	288	288	288	288	288	288	288	288	288	288	288	415	415	128	128	-	-	-	288	576	576	-	-	-	-
Port Westward G	30 yrs.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	371	371	371
Total		568	605	607	553	601	603	604	622	584	597	602	597	600	583	576	588	585	520	606	603	640	-	628	603	603

** Annual Average Theoretical Generation as estimated in September 2003. Final estimates may change.*

Mix of New Long-term Resources in 2007 (%) *		Portfolio No. 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	13 G	15 G	21 G
Resources	Typical Term																									
Renewables	20 yrs.	5%	11%	4%	5%	4%	11%	4%	10%	5%	11%	11%	11%	4%	11%	5%	5%	15%	5%	15%	4%	10%	0%	14%	4%	11%
Gas Tolling	5-20 yrs.	36%	34%	40%	34%	39%	33%	23%	19%	20%	20%	16%	20%	18%	59%	50%	72%	62%	70%	13%	0%	0%	0%	19%	12%	14%
Fixed price PPAs	5-20 yrs	9%	8%	8%	9%	8%	8%	25%	24%	26%	21%	25%	0%	8%	9%	23%	23%	23%	24%	25%	0%	0%	0%	8%	22%	14%
Port Westward F or similar	30 yrs.	51%	48%	47%	52%	48%	48%	48%	46%	49%	48%	48%	70%	69%	22%	22%	0%	0%	0%	47%	96%	90%	0%	0%	0%	0%
Port Westward G	30 yrs.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	59%	62%	61%
Total		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%		100%	100%	100%

** Percentages are based on the annual average theoretical generation as estimated in September 2003.*