Portland General Electric
2002 Integrated Resource Plan
Final Action Plan Update

Portland General Electric

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Executive Summary

In accordance with Order 89-507 investor owned utilities (IOUs) are required to file with the Oregon Public Utility Commission (OPUC or the Commission) an Integrated Resource Plan (IRP) that delineates the forecasted retail load requirements of their respective customers and the energy and capacity portfolio resources necessary to meet such requirements. On August 9, 2002, PGE filed its most recent IRP and on March 26, 2004, we filed an IRP Final Action Plan that listed base-case resource actions that PGE would pursue to meet the forecasted resource deficit between retail loads and then current power supply portfolio resources. This 2002 IRP Final Action Plan (Final Action Plan) was acknowledged by the OPUC on July 20, 2004.

The primary purpose of this report is to outline the progress that PGE has made towards achieving the targeted resource actions under our Final Action Plan. The second half of the report provides a primer into the research and processes that PGE is pursuing in support of our 2006 IRP, which we intend to file in December 2006.

PGE is pleased to report that it has achieved all of the energy and capacity resource targets in our acknowledged Final Action Plan except for an additional 38 MWa of wind energy, for which negotiations are proceeding. We are also pleased to report that once we complete our current wind energy negotiations, PGE will have in all material respects achieved all of the resource actions from our Final Action Plan.

On the energy supply side of the Final Action Plan, these actions include implementation of a long-term wind purchase, execution of mid-to-long-term power contracts, energy efficiency programs implemented by the Energy Trust of Oregon (ETO), efficiency upgrades at existing PGE generating facilities and construction of the Port Westward natural gas combined-cycle generating plant.

With respect to capacity, PGE has acquired additional peaking resources above and beyond the capacity acquired with our energy actions. These additional capacity actions include an expansion of our Dispatchable Standby Generation program at customer sites and purchasing winter peaking contracts from other energy market participants.

Equally important is PGE's pursuit of demand response opportunities through our various programs, including Demand Buy-Back, Energy Information Services, Time-of-Use pricing, load curtailment contracts,

residential direct load control, Advanced Metering Infrastructure and real-time pricing. PGE is also participating in the GridWise™ testbed, specifically researching non-wires solutions to reducing peak capacity. In addition, PGE continues to support the ETO in its development of energy efficiency initiatives.

At the same time we have taken several steps to respond to the other IRP requirements from the Commission's acknowledgement order related to transmission and new resource procurement. PGE completed a Master Funding Agreement with the ETO for the purpose of accessing ETO funds to reduce the cost of above market priced renewables to that of alternative energy opportunities. Also in support of renewables, we participated in a joint letter to Oregon's federal delegation regarding renewal of the IRS Section 45 Production Tax Credit (PTC).

In the area of transmission, PGE has actively participated in several Bonneville Power Administration (BPA) and regional forums and initiatives to explore ways to increase transmission availability across the Cascades. In some cases these efforts have resulted in new BPA business practices and increased transmission capacity. PGE has also taken steps to retain existing transmission rights to protect the reliability interests of our customers.

In preparation for our 2006 IRP filing, PGE is conducting several studies to increase our level of knowledge, analysis and dialogue regarding future resource needs and choices. The studies range in topic from coal plant technology to carbon sequestration, and from load-resource balance and reserve margin requirement to wind integration. We also conducted two surveys with our residential, business and our largest customers to determine their preferences regarding price, risk and other resource choice attributes.

At the encouragement of the OPUC and to improve the robustness of our power supply portfolio analysis, we undertook an extensive evaluation of various third party power supply portfolio modeling tools. This process resulted in the selection of the EPIS Aurora^{xmp}® model. This model will help to enhance our economic and risk assessment related to future resource decision-making. We are currently in the process of implementing the model and expect to present results later in the public process.

As we reflect on the activities to date in support of PGE's Final Action Plan, we are pleased that we have been able to substantially meet our targeted resource actions. We also remain optimistic about our ability to complete the remaining resource acquisitions, while continuing to proactively respond to the Commission's acknowledgement order.

At the same time, we recognize that the risks and environment that we face in meeting our customers' ongoing electricity needs continue to evolve. Wholesale energy market conditions, regional resource initiatives, local and national legislation and changing constituent preferences, as well as many other factors, must all be considered as we move forward. With this in mind we embark on concluding the final elements of our Final Action Plan and prepare for PGE's 2006 Integrated Resource Plan.

Introduction

Since the OPUC acknowledged our Final Action Plan in July 2004, PGE has been actively working to complete the remaining resource actions and related initiatives from the acknowledgement order. As of March 2006, we are pleased to announce that we have acquired all of the resources included in our Final Action Plan, except for an additional 38 MWa of wind energy.

We are continuing negotiations with two wind bidders from our 2003 RFP, which we anticipate to conclude shortly. We also continue to work toward addressing the demand-side and transmission issues identified in our Final Action Plan and the Commission's acknowledgement order.

The objective of this document is to provide an update regarding the actions that PGE has taken to meet the resource targets identified in our Final Action Plan. We also provide an outline of the proposed activities and schedule for our 2006 IRP, which we expect to file by the end of this year.

The following table summarizes our energy and capacity actions to date.

Energy Portfolio Actions	**2002 IRP Action Plan**		**Resource Acquired to Date**	
	2007 MWa	**2007 MW**	**MWa**	**MW**
Short-term Acquisitions[1]	125	125	125	125
Plant Upgrades	41	50	36	41
Other Operating Changes[2]	5	0	5	0
Hydro Contract Extension[3]	14	116	14	116
EE per the Energy Trust of Oregon[4]	55	79	34	49
Fixed Price PPAs	135	150	132	150
Wind (assumes capacity value = energy)[5]	65	65	27	27
Port Westward	350	375	360	382
Total Energy Actions	790	960	733	890
Additional Capacity Actions				
Dispatchable Standby Generation		30		45
Port Westard Duct Firing		25		25
Peak Tolling from Bids		400		400
Fill-in Short-Term from the Market[1]		500		500
Total Additional Capacity Actions		955		970

[1] Purchased as needed to balance resources to load.

[2] Represents PGE's expectation of ongoing operation of the Bull Run hydro project.

[3] 2002 IRP Target included an additional 49 MWa of energy at market index price, which is included here in the 125 MWa of short-term acquisitions. Total energy from hydro contract extension is 63 MWa.

[4] ETO target of 55 MWa is for acquisitions through 12/31/2007; 34 MWa acquired is for 2004 and 2005. MW savings are estimates based on implied load factors.

[5] PGE is continuing negotiations with two wind bidders to acquire the remaining 38 MWa.

Supply-Side Updates

Wind

PGE's Final Action Plan includes as an action item the acquisition of approximately 65MWa (195 MW) of wind generation, provided that the necessary transmission and integration services can be obtained, and ETO funds permit a price within the range of other alternatives. As described below, PGE has acquired 42 percent of its targeted wind generation and is actively negotiating with two counterparties to acquire additional generation to meet its target.

Klondike II Wind Farm

In December 2004 PGE executed a power purchase agreement (PPA) with PPM Energy, Inc. (PPM) for the acquisition of 100% of the generation output of the Klondike II Wind Farm located in Sherman County Oregon. The expected output of this facility is 27 MWa on an annual basis. In August of 2005 construction of this wind farm was substantially completed and the facility was synchronized to the transmission grid. Effective December 1, 2005, PGE began taking delivery of the entire output of this wind farm subject to an energy firming and shaping service provided by PPM.

The Klondike II purchase meets about 42 percent of the wind resources targeted in our Final Action Plan, based on the expected average energy. Wind in the Klondike area is generally thermally driven, which increases energy production in the late spring and summer and in the late afternoon when PGE's summer peak energy needs are higher.

Wind Actions to be Completed

PGE is actively working to complete negotiations with wind bidders to acquire the remaining 38 MWa (100 to 125 MW) of wind energy. These negotiations have been complicated by price increases in steel, concrete and other building materials, in addition to wind turbine generators. PGE is hopeful that it will be able to complete these negotiations and capture the IRS Section 45 Production Tax Credit benefit (PTC) prior to its expiration on December 31, 2007.

Final project selection will be based on pricing and terms at the time of execution. Timeliness for completing negotiations will also be a factor.

PGE will not know whether these wind proposals will require an ETO subsidy for any above-market costs until negotiations are concluded.

Port Westward

PGE's acknowledged Final Action Plan includes an action item to build or acquire 350 MWa of high efficiency gas-fired resource. Construction is well underway on PGE's new Port Westward natural gas-fired combined-cycle power plant. The project is located near Clatskanie, Oregon and adjacent to the existing PGE Beaver natural gas-fired power plant.

Once complete, the Port Westward plant is expected to be the most efficient natural gas-fired generator of its type in the Northwest region of the United States, with a heat rate of 6,826 Btu/kWh (HHV). The target completion date is March 2007, with a guaranteed substantial completion date of May 2007. The project is currently on time and within budget. As of February 28, 2006:

- Engineering was over 83 percent complete.
- Procurement was 86 percent complete.
- Construction was over 37 percent complete.

The new plant will yield 407 MW of capacity at average temperature and conditions, including 382 MW base-load plus 25 MW duct firing. Average available energy from Port Westward will be 360 MWa.

The site selection process took advantage of existing electrical transmission and natural gas transportation infrastructure. Construction of a transmission line from the Port Westward site to PGE's decommissioned Trojan site will allow for delivery of power directly into PGE's grid, avoiding connecting to BPA's system and the related transmission and ancillary services fees. Transmission line losses will also be lower, resulting in reduced costs. In combination, the avoided third-party transmission fees and line losses result in a significant cost savings for PGE customers.

To provide more fuel reliability and price stability, PGE contracted with NW Natural Gas for a 10-year firm interstate gas storage service agreement under which we will be able to store up to 1.26 million dekatherms of natural gas in the Mist gas storage facility near the Port Westward site. We will use the stored gas to augment gas pipeline service to our Beaver and Port Westward plants. Using local natural gas storage facilities allows PGE to reduce fueling costs while maintaining the reliability of the Port Westward and Beaver plants.

PGE also holds 57,000 dekatherms per day of Sumas capacity and 30,000 dekatherms per day of Rockies capacity for a total of 87,000 dekatherms per day of gas pipeline capacity. This allows PGE to fully supply Port Westward's base-load and peaking operations, and to supply Beaver with sufficient transport and storage capacity to meet its expected dispatch and fueling needs.

Plant Efficiency Upgrades

In its Final Action Plan PGE identified as existing actions a number of plant improvements. We have since completed upgrades to our Beaver, Boardman and Faraday plants, for an additional 36 MWa of energy and 41 MW of capacity. These results are slightly short of our Final Action Plan target of 41 MWa and 50 MW, which was based on engineering estimates at that time.

For Beaver and Boardman, the new efficiency ratings require no additional fuel and result in no increase in plant emissions. For Faraday, the improvements will allow us to realize more energy production without requiring extra water to pass through the turbines. The upgrades are:

- Faraday – 4.3 percent increase in output, 1 MWa.
- Beaver – 2.1 percent, 18 MWa.
- Boardman – 1.8 percent, 17 MWa.

Contract Renewals

PGE also listed as a completed action item in its Final Action Plan the renewal of our contract with the Confederated Tribes of Warm Springs for the output of their share of the Pelton-Round Butte hydro-generation projects and the Pelton re-regulating dam. These contracts add 65 MWa of energy and 161 MW of capacity from January 2007 through February 2012, versus estimated Final Action Plan targets of 63 MWa and 165 MW. Of the 65 MWa, 14 MWa is received at a fixed price, with the remainder being received at a market index price.

Power Purchase Agreements for Energy

Our Final Action Plan included as an acknowledged action item the acquisition of 135 MWa in fixed price PPAs for durations of five to ten years. As described below, PGE has acquired 132 MWa in PPAs.

We executed a 10-year, 100 MW fixed-price PPA. Under this agreement PGE receives energy according to actual production at the power plant. Based on expected plant availability, we anticipate receiving about 93 MWa of energy over the contract term. We also executed two contracts for system power, including a five-year fixed price PPA for 25 MWa, along with a 25 MW base-load tolling agreement, which we expect will provide 14 MWa of energy.

Capacity Contracts

In the Final Action Plan PGE included 400 MW of peak tolling agreements. PGE has now completed this action item by executing two contracts totaling 400 MW of peak system tolling to meet winter peak load demands. Both capacity contracts are natural gas peak tolling arrangements, whereby PGE has the right to receive power based on a pre-determined plant heat rate and a regional market price for gas.

One of the contracts is for up to 300 MW available during the winter months from 2006 through April 2011. The other contract for 100 MW is available for peak winter months beginning in December 2005 and ending in 2010.

Customer Sited Combined Heat and Power

As part of our Final Action Plan, we committed to evaluate the market potential for combined heat and power (CHP) systems at customer sites. The following summarizes PGE's activities and findings in this area to date.

Increased market penetration by CHP can potentially produce economic benefits, energy savings, and reductions in pollutants such as NOx and CO_2 in the region. From a generation host perspective, CHP can provide heat or steam for onsite processes, and also meet all or part of the host's onsite power needs. However, for CHP to be cost-effective and energy efficient, it must be used in applications that have highly coincidental electric and thermal loads and have electric-to-thermal demand ratios in the 0.5 to 2.5 range. Scale of the resource and thermal load also has a significant effect on cost.

PGE continues to work with the industrial candidates in our service territory to evaluate potential combined heat and power projects. Following acknowledgement of our Final Action Plan, PGE also commissioned a study by an independent consultant to assess the technical and economic market potential for customer sited CHP in the commercial and institutional sectors. The study showed that larger applications in markets like hospitals and universities offer the best technical viability and economics for using CHP. These industries have access to relatively low cost capital, as well as the necessary staff levels to maintain and operate a CHP system.

Other industries that appear to offer good economic potential such as nursing homes and prisons may be disadvantaged in the areas of O&M staff and access to capital, and also view investing in and operating CHP systems as distant from their core business. Other barriers to CHP include environmental and siting regulations.

PGE is an active member of the Combined Heat and Power Consortium hosted by NW Natural Gas. Through the Consortium, PGE has worked with two local hospitals and a university to develop combined heat and power projects, although no projects have yet been implemented.

At the same time, PGE continues to proactively participate in OPUC proceedings that are related to or influence the development of CHP resources. In particular, the current UM-1129 docket and the Partial Requirements rate schedules resulting from the UE-158 process provide additional clarity with respect to important issues affecting CHP.

One of the goals of phase one of the currently open UM-1129 Qualifying Facility (QF) docket is to establish a standard contract and framework for Oregon electric utilities to purchase power from QFs that are less than 10 MW in size. Phase two of this docket addresses contract terms and conditions for larger (greater than 10 MW) QFs.

Following issuance of the Final Action Plan, PGE worked with interested parties to develop a series of Partial Requirements schedules for customers with on-site generation. These schedules were developed in connection with the UE-158 investigation and in cooperation with various stakeholders including OPUC Staff, Industrial Customers of Northwest Utilities, Oregon Department of Energy, and select customers. Schedules 75 and 76R are for customers receiving their energy supply from PGE.

The Partial Requirements rate schedules provide consumers who have on-site generation with a reasonable set of charges and options for utilization of the PGE system. The schedules also provide that other consumers on the PGE system are reasonably assured that the Partial Requirements consumer is not placing unjustified burdens and costs on the system. Finally, the Partial Requirements schedules support an objective of the Commission to remove barriers to the development of distributed generation.

We continue to evaluate these issues, participate in local and regional forums, and maintain an open dialogue with customers and interested parties with respect to CHP. By doing so, we hope to increase our awareness and understanding of the market potential, assess ways to overcome barriers and seek technically viable and cost-effective CHP opportunities to help meet our future resource needs.

Dispatchable Standby Generation

In the 2002 IRP we listed Dispatchable Standby Generation (DSG) as one of our capacity resources.[1] As part of our acknowledged action items, we committed to developing a 30 MW "virtual peaking plant" by the winter of 2006-07. By the end of 2005 we had 29 MW on line and available for dispatch. We have another 16 MW signed or under construction, for a total of 45 MW of dispatchable standby generation available by the end of 2007.

We have found that customer enthusiasm and adoption rates for this program have been higher than we originally anticipated. The high levels of customer interest and participation have allowed PGE to establish one of the most successful customer-based capacity programs of its kind. This option, because of its distributed nature, also provides reliability benefits for PGE and the host customers.

DSG is a high quality, cost-effective capacity resource that also serves as reserve capacity. The projects pursued were either new installations or major rehabilitations that represented lost opportunities if the construction window was missed.

Since we have received inquiries and further interest from customers beyond our current implementation, we believe that the DSG program could potentially be expanded to help meet more of PGE's future capacity needs. Ultimately, we may be able to develop as much as 100 MW, depending on future economics and customer adoption rates.

Because this resource relies on the operation of diesel-fueled, back-up generators at non-residential customer sites, we are limited in the number of hours per year that we can operate each plant. However, this limitation does not impair the effectiveness of DSG as a capacity option,

[1] See Appendix K, p. 179.

as we only intend to dispatch the resource during infrequent super-peak events and to meet PGE and customer reliability needs.

Energy Trust of Oregon Master Service Agreement

In 2005 PGE executed a Master Funding Agreement with the ETO that will expedite our acquisition of future renewables projects. The agreement designated ETO funds to assist PGE in acquiring new renewable energy resources by subsidizing any above-market costs. The agreement also outlines all key terms and conditions for requesting, securing and administering subsidy funds for such projects.

Joint Letter to Oregon's Delegation

We participated in a joint letter to Oregon's federal congressional delegation urging the renewal of the PTC for renewables. Both U.S. Senators voted for the subsequent extension. The other co-signers included: Puget Sound Energy; PacifiCorp; NorthWestern Corporation; Citizens' Utility Board of Oregon; and the Washington State Office of Community, Trade and Economic Development (see appendix).

We joined the Legislative Committee of the American Wind Energy Association (AWEA) in early 2005 and worked with them and other members to secure PTC extension. We also visited our Congressional delegation on the Ways and Means Committee twice in Washington, D.C. to discuss these issues.

Demand-Side Updates

PGE's Final Action Plan included as an action item the acquisition of capacity through customer demand reduction programs. As described more fully below, PGE has a number of such programs underway. PGE also continues to assess the development of demand response options within its service territory and to monitor demand-side initiatives regionally and nationally.

Demand Buy-Back Program

We offer large, non-residential customers our Demand Buy-Back (DBB) program, which can be implemented during critical peak hours. Because DBB is a voluntary program with responsiveness at the discretion of participating customers, we do not consider it to be a firm capacity resource. However, depending on customer responsiveness, it should help reduce our capacity needs during the highest price peak hours.

The program typically is triggered under 1-in-5 peak load conditions, and has been effective in the past for reducing peak demand, where savings offered by PGE were also high enough to attract customer participation. While agreeing to provide over 25 MW of capacity reductions, our customers tell us that their responsiveness depends on a variety of business and operating conditions, in addition to the curtailment payments offered by PGE.

Given these factors, few customers have expressed a willingness to enter into firm, non-discretionary arrangements. Based on our interviews with customers, we determined that PGE can count on approximately 3 to 3.5 MW of capacity at any time for resource planning purposes through the DBB program.

Energy Information Service

All Schedule 83 customers with greater than 30 kW of demand are eligible for PGE's Energy Information Services (EIS). By knowing when peaks occur, customers can analyze their processes and respond accordingly. In some instances, this information has helped customers know which processes they can alter or shift to reduce peaks, or to participate in PGE demand response programs. EIS can also be used to track the effects of energy efficiency initiatives.

Approximately 90 customers, representing about 540 meters, are currently signed up for the service. This is a small percentage of our 8,000 business customers with loads above 30 kW, and about 14 percent of our 630 top- and mid-tier customers with loads over 500 kW.

Time-of-Use Pricing Option

Beside load control programs, we offer a time-of-use pricing option to residential customers. A relatively low number of customers, about 1,800, are currently enrolled in the program. While participation has been limited, the customers in the program report that they are pleased with the option. Though not economic on a total resource cost basis today, time varying rates may become more viable in the future.

Our time-of-use evaluation study, revised in 2004, shows the average winter peak load shift to be about 0.2 kW per node. With 1,800 customers enrolled in time-of-use, the total capacity reduction is minimal. With our relatively low regional system cost, marketing efforts to further increase enrollment would have an adverse economic effect because promotion costs would exceed the avoided cost savings.

Load Curtailment Contracts

We also offer large, non-residential customers customized contracts for load curtailments under peak conditions. Because these contracts require mandatory curtailments, we consider executed contracts to be a firm resource.

Load curtailment contracts are customized to give our large customers the opportunity to help design the structure that would be the best fit for their operations for reducing load during peak demand periods.

The negotiated pricing for these contracts is based on our market rates and the cost of avoided capacity at the time. Since we filed our Final Action Plan, we sent invitations to the 70 most likely customers that might participate in our load control program, based on their size and the nature of their business operations. So far, one customer has shown interest but a contract was not negotiated.

We continue to monitor the key cost drivers and explore load curtailment contracts with our customers as an alternative to supply-side capacity acquisitions.

Residential Direct Load Control

PGE has conducted pilot programs for direct load control of space and water heating load. The results show that neither is yet an economic capacity resource given PGE's prices, resource characteristics and cost structure.

Load control programs appear to be more economic in warmer regions of the country. For example, PacifiCorp and Comverge state that their load control contract is economic in Utah. Also, Florida Power & Light indicates that their load control program is cost-effective. At the same time, some Southern California IOUs have said that their load control programs are not yet cost-effective, but they run the programs at the State's direction.

Such programs control residential air conditioning and pumping for irrigation, and reduce summer peaking in areas that are constrained in the summer. Summer air conditioning tends to be a season-long event, compared with short and limited durations for winter space heat control. Longer durations allow the programs to overcome the initial investment hurdle and the ongoing program costs.

The peak capacity resources for these summer peaking utilities are typically more expensive. In addition, summer peaking utilities do not enjoy the low-cost hydro flexibility that is largely unique to the Pacific Northwest. As a result, cooling demand-based load control programs tend to be more cost effective in other regions, as they typically displace higher cost peaking resources and the peaking needs they address are more frequent. PGE continues to advance our work in this area.

Advanced Metering Infrastructure Update

PGE is currently evaluating a proposed Advanced Metering Infrastructure (AMI) system that would provide the necessary technology and systems to allow PGE to add the capability to offer a sophisticated demand-side program. An AMI system would enable PGE to offer more advanced pricing and load control options.

A report issued by the U.S. Department of Energy recently recommended adopting enabling technologies, including automated metering, as a means of encouraging the growth of demand response.[2]

If AMI is implemented, some of the demand-response benefits will not be recognized immediately and some will require additional investment. For example, the proposed AMI system will allow us to offer smart appliance services, but not until our customers purchase smart appliances. Other functions for these programs will be developed in the future. PGE has requested OPUC approval of its AMI system.

Real-Time Pricing Pilot

Schedule 87 for customers with loads of one MW and above is our real-time pricing pilot. The pilot is intended to reduce demand by focusing on load curtailments when prices are high. Participating non-residential customers receive day-ahead notification of hourly prices, giving them the opportunity to reduce peak loads, or to shift loads to less expensive off-peak hours.

The pilot results demonstrated that while some customers expressed interest in the option, none have signed up to participate. Reasons for this may include the availability of other PGE DSM programs and apprehension about market price exposure, as well as customer hesitancy to disrupt or alter their business operations. Schedule 87 customers cannot concurrently participate in PGE's Demand Buy Back, Dispatchable Standby Generation, or any of our market-based options.

Non-Wires Market Transformation

PGE entered into the GridWise™ demonstration project to determine if smart controls can limit power fluctuations and make the electric grid more resilient and cost-effective. The project includes an experiment in which customer loads can be controlled through a two-way energy price bidding process, and a field test of Grid Friendly™ appliances that automatically sense grid condition and curtail the appliance loads when doing so will help the electrical power grid.

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[2] See *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*, p. vii, xx, 58-59. U.S. Dept. of Energy, Feb. 2006.

Energy Efficiency

PGE's Final Action Plan targeted 55 MWa of Energy Efficiency to be implemented through the ETO by the end of 2007. The ETO reports that they have captured 9.1 MWa of energy efficiency with PGE customers in 2004 and nearly 25 MWa in 2005, for a total of 34 MWa towards PGE's Final Action Plan target of 55 MWa. The 2005 numbers are preliminary as of March 2006. Based on this progress, the ETO appears to be well on-track to meet or exceed the energy efficiency target from our Final Action Plan.

ETO Annual Energy Savings (MWa)

	2004	2005	Total
Residential	4.0	4.2	8.2
Commercial	3.6	5.4	9.0
Industrial	1.5	15.3	16.8
Total	9.1	24.9	34.0

The Energy Trust collected over $25 million from PGE's customers during 2005 as part of the public purpose charge, and issued almost $19 million in incentives during the same period. PGE will continue to support and monitor the ETO's progress in this area.

Transmission Conditions in our IRP Acknowledgement

The Commission's acknowledgement of our Final Action Plan was conditioned on PGE taking a number of actions related to developing transmission capacity over the Cascades. As discussed below, PGE has been proactive in working with other regional entities to satisfy the conditions.

1. PGE must initiate discussions with Staff, renewable developers, BPA, ETO and other stakeholders to discuss constraints to competitive renewable development in the region.

PGE is actively engaged in regional discussions regarding constraints to competitive renewable development including:

McNary Open Season – BPA has planned to build a new transmission line from the McNary substation to the John Day substation and has offered to sell the capacity in an open season bid to interested parties. This proposed new transmission line, if built, would relieve transmission constraints in the McNary area.

PGE actively participated in the regional open season workshops and supported the process by submitting a request for 60 MW of firm transmission from the Stateline area to PGE's system. The McNary open season process has been suspended and replaced by BPA's modified available transmission capacity (ATC) methodology initiative, which should accomplish a similar result, i.e., new ATC over the West of McNary pathway.

Modified ATC Methodology – BPA changed the assumptions used to calculate the ATC on BPA transmission lines. This process has resulted in additional ATC over many of BPA's critical pathways including West of McNary. PGE actively participated in BPA's regional workshops and submitted comments and recommendations. PGE met twice with BPA in negotiation sessions to assure that the new methodology did not adversely impact current transmission contract rights. In the end, PGE supported BPA's methodology, and on July 1, 2005, BPA posted increased ATC over their system based on the modified methodology. Subsequent refinements have resulted in additional ATC since July 2005.

Conditional Firm Transmission Product – PGE supported the development of a conditional firm product during the BPA's 2006 Transmission Rate Case. One of the primary objectives of this initiative is to enable cost-effective transmission of intermittent wind without harming or burdening other transmission customers and users. This resulted in BPA's commitment to develop the product and to run an expedited 7(i) process to price the product if needed.

BPA studied the proposal and formed a new products work group. PGE was an active participant in this work group. BPA issued its initial draft proposal for a new product on December 23, 2004. After a review and comment period, BPA issued a revision to the new product proposal for Conditional Firm on June 6, 2005.

BPA has put this proposal on hold, pending completion of BPA's new Constraint Schedule Management (CSM) system. The CSM will give BPA the ability to delineate non-firm transmission over a path and curtail it before Conditional Firm. BPA has initiated regional dialogue on an implementation plan for CSM. PGE is actively engaged in the process.

Modification of BPA Firm Redirect Business Practice – PGE worked with BPA to modify its Firm Redirect business practice to allow the option to move Section 2.2 roll-over rights to the redirected point of receipt. This flexibility will enable current transmission holders who already possess firm transmission rights the ability to move those rights to new resources (e.g. new wind projects) subject to available transmission capacity. BPA has modified their business practices to allow transfer of Section 2.2 roll-over rights.

Grid West – PGE is actively participating in regional efforts to more efficiently run the Northwest transmission system, and has agreed to provide funding to Grid West, along with other parties, to allow the organization to develop a business plan. PGE will then decide whether to participate in Grid West development. BPA has recently discontinued its participation in Grid West and has initiated a parallel process. PGE will monitor and participate in the BPA effort as appropriate.

2. PGE must include an action item in its 2005 IRP to address how it will work with BPA and others to develop transmission capacity over the Cascades so that additional resources are accessible to PGE at a reasonable price.

OSU Transmission Study – In 2005 PGE engaged the Oregon State University (OSU) Engineering department to assist us in evaluating transmission options that would result in the ability to more efficiently utilize any remaining existing capacity over the Cascades, as well as potential facility additions that could result in new usable capacity. The primary objective of our contract with OSU was to conduct a physical transmission system examination of the constraints for moving power to PGE's system from the north, through the Interstate-5 corridor, and across the Cascades from Eastern Oregon.

The initial purpose of the study was to evaluate transmission flows and potential system upgrades and alternatives to relieve congestion on the South of Allston cutplane. The South of Allston cutplane, located north of Portland, is currently one of the most highly congested flow-gates on the BPA system and, as a result and due to its proximity to the PGE system, severely limits PGE's ability to secure new firm transmission rights from many points around the region, including the eastside of BPA's system.

Since the constraint caused by this cutplane will also block any effective use of new transmission capacity additions across the Cascades, South of Allston represents a least common denominator impediment to securing new resources to meet customers' future energy needs. Accordingly, first examining the physical causes of the South of Allston cutplane and potential ways to alleviate the constraint is critical.

PGE also asked OSU to investigate the technical feasibility of building a new transmission line from the McNary area to PGE's service territory in Salem. This expansion would use PGE's existing rights-of-way and would upgrade the Round Butte-Bethel line that connects the Pelton and Round Butte projects to PGE's system. We are currently referring to this potential transmission expansion as the "Southern Crossing." We selected this path for evaluation to potentially increase transmission capacity across the Cascades for several reasons:

- If new transmission facilities were built, the Southern Crossing could provide additional transmission capacity form Eastern Oregon to the Willamette Valley. Such new facilities would potentially relieve current east-to-west transmission congestion and provide additional capacity for new resources on the east side of the Cascades, including wind.
- The Pelton-Round Butte to Salem path offers the potential to use existing transmission corridors and rights-of-way, reducing such obstacles as permitting and securing easements.
- The Southern Crossing study offers synergy with other BPA and regional initiatives to increase east-to-west transmission efficiency and capacity.

Given the complexity and time-intensiveness of the South of Allston study, OSU was unable to complete all phases of the technical study for Southern Crossing under the 2005 scope of work. Therefore, we intend to evaluate alternatives to complete this technical feasibility study in 2006, including working with members of the OSU team that conducted phase I of the study.

PGE is also participating in several sub-regional transmission expansion planning efforts facilitated by the Northwest Power Pool. The Northwest Transmission Assessment Committee (NTAC) is currently assessing several regional transmission expansion options, including the Montana-Northwest Study Group, the Canada-Northwest-California Study Group, and the Northwest Wind Integration Study Group.

3. PGE must demonstrate that it has made reasonable efforts to acquire, retain or option cost effective transmission capacity over the Cascades before issuing its next RFP.

Point-to-Point Transmission – PGE procures firm BPA transmission capacity sufficient to meet 1-in-2 peak winter loads. This includes 750 MW of Rocky Reach and 400 MW of John Day-Big Eddy point-to-point (PTP) transmission service. Adding Port Westward in 2007 reduces our transmission needs by over 400 MW. We have worked with BPA to increase our ability to redirect these PTP purchases to deliver other resources, including renewables, to our load. PGE has extended both PTP agreements through 2010.

BPA's Firming and Shaping Product – Since wind is an intermittent resource with only limited predictability, additional resources and strategies are necessary to absorb the variability and allow utilities to meet unexpected deviations in generation. Following acknowledgement of our Final Action Plan, PGE continued its work with BPA to develop a product that provides storage and integration services for wind. However, BPA has since discontinued its product offering and ceased activity in this area due to uncertainty regarding their role in supplying the future energy and capacity needs of public customers.

BPA's proposed offering was structurally promising, but was limited in effectiveness as a long-term solution (only through 2011), due to BPA's inability to make a longer-term price commitment. We are also concerned that recurring court rulings with respect to federal damn operations will further diminish BPA's ability to offer this service in the future.

Looking Ahead – PGE's 2006 Integrated Resource Plan

As we move forward with completing the targeted resource and capacity actions from our Final Action Plan, we have begun to look ahead toward our next IRP, which we intend to file in December 2006. In preparation for our 2006 IRP, PGE has conducted or initiated a number of technical and economic research efforts to enhance our understanding of fundamental supply, demand, and technology drivers and influences that will ultimately impact the cost, risk and availability of future resources.

We are in the process of evaluating the future availability of our existing resources and forecasted customer energy needs to determine the timing and extent of our future resource requirements. At the same time, we have conducted customer surveys and a forum to directly gauge customer knowledge, preferences and concerns with respect to future resource choices. In the area of analysis, we have conducted a review of several third-party IRP analytical tools and selected a new model to enhance our risk and economic evaluation and decision-making. Finally, we plan to initiate a robust public process to provide the opportunity for all constituents to provide input and comment on the results of our research and analysis. These efforts are explained in greater detail below.

2006 IRP Studies

We are conducting a number of studies to support our analysis of IRP issues and concerns. Our goal is to better understand and evaluate such key issues as expansion of renewable resources, next-generation coal plants, carbon sequestration feasibility and reserve margins. This section provides a brief overview of studies that are currently planned or in-process to support our 2006 IRP.

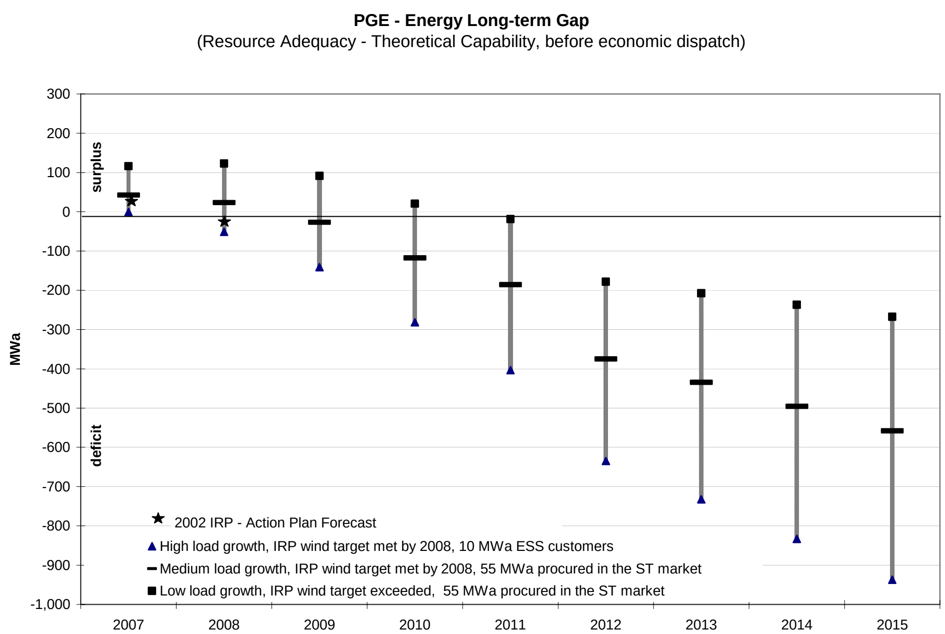
Load-Resource Balance

In our Final Action Plan we committed to procure approximately 790 MWa of resources to fill our expected annual average energy need by 2007-2008. We now expect to be in approximate load-resource balance on a resource adequacy basis by 2007-2008.

However, as we move forward we expect to experience customer load growth, resulting in a renewed deficit on a resource adequacy basis, and significant short-falls on an economic dispatch basis. This growing deficit is also driven by changes in our existing resource base over time. During the next few years some of our existing resources and long-term contracts will expire or are likely to be reduced in volume upon renewal.

In our 2006 IRP we will highlight the drivers of the projected gap and expand our evaluation beyond the traditional resource adequacy-based load-resource analysis to also consider an economic dispatch approach. This latter approach is based on the expected future dispatch of our thermal plants and contracts, and more accurately considers our actual short- to mid-term resource procurement needs.

The chart below shows the expected energy gaps for the years 2007 through 2015 based on a resource adequacy approach. For each year we have displayed a range of potential load and resource outcomes based on uncertainty surrounding some of the key assumptions and drivers in our forecast.



This figure shows three possible scenarios:

- High load growth of 3 to 3.3 percent a year with 10 MWa choosing service from an ESS. This is the maximum resource need with significant resource deficits starting in 2009.
- Medium load growth of 1.7 to 2.2 percent a year with 55 MWa choosing service from an ESS or market index pricing options. This is our initial modeling assumption for customers who will not return to a cost-of-service rate upon expiration of the shopping credit tariff

provision. [3] In this scenario, deficits begin to appear in 2010 and 2011 and become material in 2012.

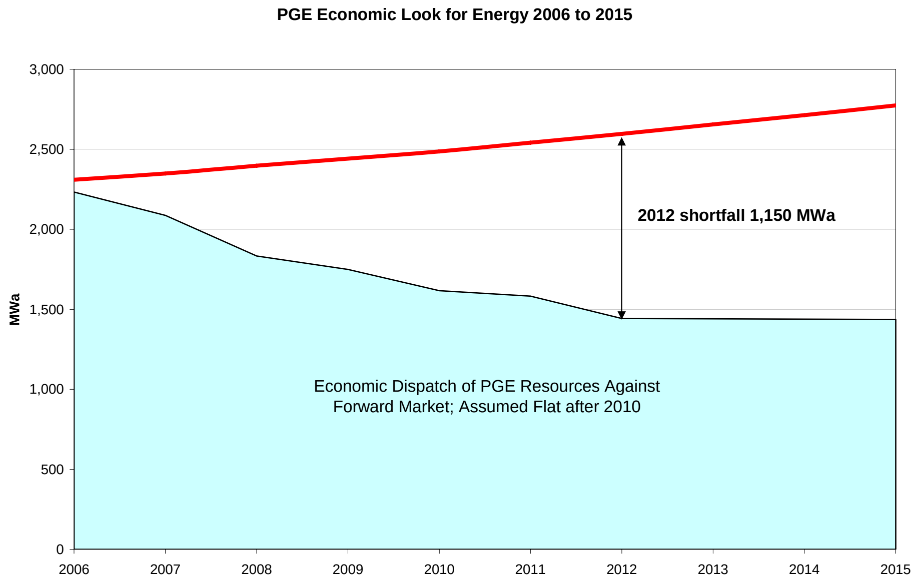
- Low load growth of 1.1 percent a year with 55 MWa selecting ESS service or market index pricing options. Under this scenario we also forecast increasing resource deficits by 2012.

In the longer term, the energy gap range widens because of load uncertainty, and the deficits deepen due to a material reduction in existing resources in 2012 caused by the expiration or renegotiation of several mid- to long-term contracts. These include Mid-Columbia hydro, Confederated Tribes of the Warm Springs (Pelton-Round Butte) and PPAs executed in connection with the 2002 IRP Final Action Plan.

For resources that will be renegotiated or renewed, we expect that we will retain less output from the resource than we currently enjoy. This assumption is based on discussions with the resource owners or suppliers and by observing the results of renewals or renegotiation activities by other utilities in the region for similar contracts.

The figure above shows the traditional IRP load resource balance from a resource adequacy perspective, before considering economic dispatch of our thermal plants and contracts. Load and resources are computed assuming "normal" conditions such as weather, hydro production and plant operations. The chart below shows PGE's estimated future resource needs taking into account economic dispatch of our resources.

[3] A shopping credit is an incentive for customers to acquire energy from an ESS. The 10 MWa estimate is consistent with PGE's general rate case filing (UE 180). We assumed 55 MWa from ESS or variable pricing options in our IRP Key Customer Workshop on March 1, 2006.

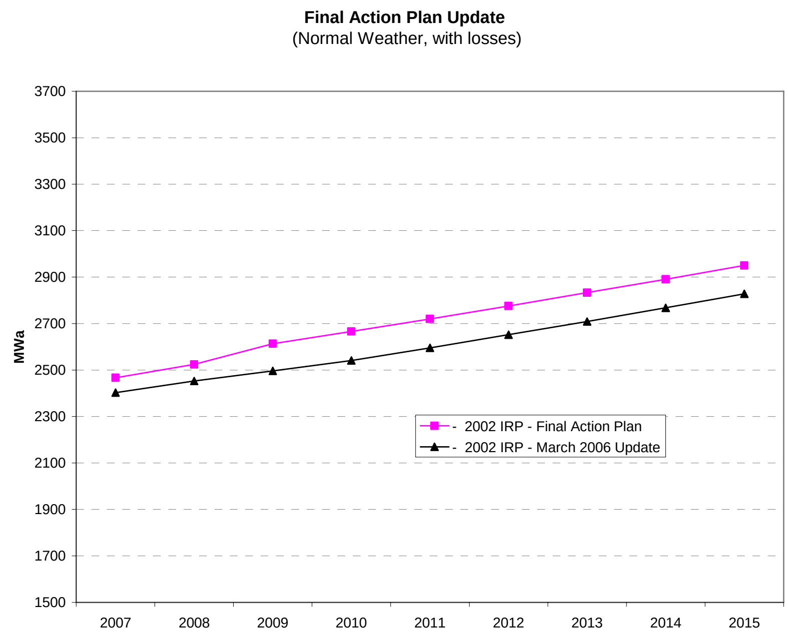


The relative dispatch cost of our natural gas-fired resources and contracts compared to the marginal price of electricity in the market continues to change over time as more efficient resources, like Port Westward, are added to the Pacific Northwest (PNW) regional portfolio. In addition, the abundance of hydro generation in the PNW results in displacement of most thermal resources during the spring and early summer months and at certain other times during off-peak hours. As a result, the load-resource balance of our portfolio on a resource adequacy basis and an economic dispatch basis diverge. The latter assessment shows larger deficits and a higher reliance on short-term market purchases.

Given the continued increase in efficiency for the regional energy portfolio, higher heat rate thermal units such as Beaver are becoming intermediate duty plants that provide base-load energy only during the peak months and peaking capacity during the balance of the year. We also account for seasonal variations in market pricing and market-clearing heat rates that periodically displace more efficient units such as Coyote and Port Westward. These variations are largely driven by abundant regional hydro energy in the spring and early summer months.

In our 2006 IRP we intend to assess our resource needs on a resource adequacy and economic dispatch basis to better understand the costs and risks of managing our portfolio and implementing new resource decisions.

The figure below compares the load forecast of the Final Action Plan with the most recent forecast. We report system load net of energy efficiency measures.



The current annual average load projection for 2007 is about 65 MWa lower than what we published in our Final Action Plan. By 2010, the difference grows to 125 MWa. The lower load projection is explained by:

- Reductions in energy consumption caused by sustained high energy prices.
- Industry or business specific factors affecting a few large customers.

Our industrial and commercial load is affected by lower consumption from three large customers. One customer revised its expansion plans for its Oregon operations, another increased its amount of self generation, and a third customer increased its efficiency with an ETO-sponsored project.

Based on the preliminary analysis described above, we expect that new mid- to long-term resources will be required by 2012 to ensure that we meet our customers' energy requirements. In that year our mid-case estimate shows a deficit of about 370 MWa, on a resource adequacy basis, to meet our annual average energy needs. Capacity needs by 2012 are greater and will be addressed in detail in our 2006 IRP.

Reserve Margin Requirement

This study will assess the risks and costs of the amount of resources that PGE maintains to meet peak load requirements and unexpected deviations in load and generation. The goal of this study is to examine the cost and risk trade-off of providing reliability and price stability at various levels. Besides looking at our reliability and economic metrics, we will also examine what other utilities have proposed and what has been acknowledged in their IRPs.

We will also consider the current initiative to evaluate reserve margins that the Northwest Power and Conservation Council (NWPCC) is undertaking, in collaboration with regional utilities, to define guidelines and metrics for measuring energy and capacity resource adequacy.

Wind Integration

This analysis will help define how much wind PGE can integrate and determine the supply curve of integrating wind as higher volumes are added to our system. Through the study we intend to examine both operational and reliability considerations, as well as economic impacts.

Uncertainty Analysis

As part of our resource and portfolio modeling PGE intends to conduct various forms of analysis, including scenario, sensitivity and stochastic probabilistic analysis. Performing and considering the results of different analytical approaches is necessary to adequately assess the risk and economic factors associated with future resource decisions and to provide better insights regarding potential future outcomes.

To ensure that our analysis is robust and well-considered, PGE is engaging an outside expert to study uncertain power supply factors such as natural gas and electricity prices, loads, and hydro output. This assessment of the relationships and uncertainties of these key economic drivers will inform our resource choices.

Customer Outreach

An important objective for our 2006 IRP process is to ensure that PGE has conducted a robust dialogue with all stakeholders regarding future resource needs and choices. Providing opportunities for our customers to participate in the process and voice their preferences is key to meeting that objective. To accomplish this goal, PGE has conducted a three-phased customer outreach research initiative to directly assess customer views about risk and value considerations for resource decisions. We also learned about specific customer preferences for potential resource alternatives.

- Phase one, conducted in mid-2005, involved a series of focus groups, two for mid-tier businesses, and two for residential customers. Our industrial key accounts were also sampled through in-depth interviews. The focus groups provided an opportunity to qualitatively assess customer priorities and receive direct unfiltered responses regarding electric supply choices.
- Phase two was conducted in late-2005 using a randomly sampled survey approach for residential, commercial and large industrial customers. The statistically valid sampling included survey results that are now being analyzed and tabulated to provide a quantitative assessment of customer power supply preferences and attitudes for important resource considerations such as cost, price stability, reliability and environmental impacts.
- Our most recent activity was a Key Customer Group IRP Forum held in March 2006. The forum included representatives from several of our largest business customers, as well as PGE's IRP managers and resource subject matter experts. During the forum we presented information related to our potential energy needs and resource alternatives to meet those needs. We also solicited direct responses from the participants regarding their objectives, concerns and preferences for PGE's energy supply and resource choices.

The combined results of these customer studies will be summarized in our 2006 IRP and we anticipate using these responses to inform our resource decisions.

Transmission Study

As described earlier in this document (see "Transmission Conditions in our IRP Acknowledgement"), PGE is conducting transmission studies to assess potential solutions to enable new generation resources from east of the Cascades. The studies will evaluate the technical feasibility of potential system upgrades and improvements to existing transmission facilities within the South of Allston cutplane. This system constraint must be remedied to make effective use of new transmission capacity across the Cascades.

We are also studying a cross-Cascades transmission path from Eastern Oregon to the Willamette Valley by upgrading and expanding the reach of existing PGE transmission facilities. This latter expansion has the goal of increasing capacity and integrating new sources of supply.

Fuels and Generation Technologies

Since acknowledgement of our Final Action Plan, the wholesale energy markets and resource technologies have continued to evolve. During this time many events have occurred that have affected the availability and price of generating electricity. One of the most significant of these changes has been in the area of fuel cost and availability.

Over the last few years increases in hydro-carbon commodity prices have impacted virtually all fossil-fueled generation sources. Prices for natural gas, oil and coal have all experienced increased volatility and higher price levels. Beyond these changes there is an increasing awareness that domestic extraction of natural gas is not keeping pace with demand. Due to these factors and others it will be increasingly necessary to consider alternative energy sources.

PGE thus intends to examine several alternative resources, fuels and related initiatives. In addition to continuing our close examination of expanding renewable energy and demand-side options, PGE also intends to consider next-generation and clean coal technologies, global and national LNG forecasts and West-coast opportunities, future emissions initiatives and impacts (including carbon sequestration feasibility) and emerging generation technologies. By doing so, we hope to deepen our analysis and discussion of the risks and trade-offs associated with our future resource options.

Coal Technology Study

In 2005 PGE retained Black & Veatch to investigate and compare coal-fueled generating technology options for PGE's integrated resource plan. The study compared super-critical pulverized coal (SCPC) and integrated gasification combined cycle (IGCC) technologies. Performance and cost estimates were developed on the basis of a Powder River Basin coal supply.

To provide specific and accurate costs, the study is based on adding a second unit at the site of our Boardman Coal Plant. The study results can also be generalized to evaluate the cost of a mine-mouth site. We will assess these two technologies and their related costs and risks independently, considering the relative merits of each technology.

Study deliverables include technical specifications, cost estimates (installed cost per kW), emissions estimates and development timelines, along with conclusions and recommendations about the generation technologies based on economics and risk factors.

Carbon Sequestration

Recently PGE engaged Cornforth, a local geology consultant, to do a preliminary assessment of the geological carbon sequestration potential in the lower Columbia River basin (the area of our Boardman site) and at mine-mouth coal sites in Montana or Wyoming. This study will also identify the potential for collaborative work with WestCarb and Big Sky. The results of this study will be used to inform our assessment of the emissions-related risks and potential mitigation factors for carbon-intensive thermal generation resources.

Fuels Research – Coal

PGE is reviewing long-term forecasts by Hill & Associates, Inc. for U.S. steam coal and Powder River Basin coal supply, demand, and prices. We are also following allowance values for sulfur dioxide, nitrogen oxides, carbon dioxide, and mercury emissions. In addition, we are evaluating the effects of the EPA's Clean Air Interstate Rule and Clean Air Mercury Rule, and are monitoring legislation related to proposed emissions limits and cap and trade programs.

Fuel Research – Natural Gas

PGE has subscribed to weekly, monthly and annual reports from PIRA Energy Group to better understand short and long-term natural gas fundamentals with respect to supply, demand and price. For IRP purposes PGE will focus on the long-term studies PIRA conducts.

Fuel Research – Liquefied Natural Gas

PGE has subscribed to PIRA's Global Liquefied Natural Gas (LNG) service and will review factors affecting supply, demand and the price of LNG. We will also assess the potential for LNG to become a future fuel source for regional and PGE natural gas-fired generating plants by monitoring efforts to bring LNG regasification facilities to Oregon and to the West Coast.

Pacific Northwest Climate Study

PGE has commissioned a study from the University of Washington to assess the potential effects specific to the Pacific Northwest of global climate change, including potential impacts to precipitation and snow-pack. The study will also assess potential temperature changes that could affect our heating and air conditioning needs.

EPRI Wave Energy

Wave energy is an emerging technology that is currently receiving greater attention due to its potential global abundance. Should this technology be further developed and commercialized, the potential benefits to Oregon and PGE customers could be significant. As a result, PGE has taken steps to monitor and support local wave energy initiatives. On the local front, Electric Power Research Institute (EPRI) and Oregon State University are conducting a wave-action study to assess various technologies for generating electricity from waves. EPRI has published their *Oregon Offshore Wave Power Demonstration Project* report, and has turned all Oregon wave energy research over to OSU and People of Oregon for Wave Energy Resources (POWER) for further research and development.

POWER is headed by Justin Klure of the Oregon Department of Energy, and seeks to establish a wave energy demonstration project offshore from Reedsport, Oregon. POWER's long-term goal is to support installation of one or more utility-scale wave energy parks along the Oregon coast, which would provide local jobs for fabrication and servicing the equipment.

OSU may conduct research on various wave energy generator devices at a node on the demonstration project. Alternatively, they may establish an ocean wave research area closer to Newport and the Hatfield Marine Science Center. PGE and Oregon Iron Works are supporting OSU's development of a linear test bed for conducting research on prototype wave energy generators.

Selecting PGE's IRP Analytical Model

In the Acknowledgement Order for our 2002 IRP, the OPUC encouraged PGE to acquire more sophisticated and powerful analytical tools before proceeding with the next IRP. After exhaustive due diligence of several analytical products, we selected EPIS' Aurora^{xmp}® model in December 2005.

Aurora compared favorably with other models because of its user-friendly interface and its extensive data base. It is also well accepted for use in long-term energy planning analysis in the Pacific Northwest. Regional users of Aurora include: NWPCC, Avista, Idaho Power Company and Puget Sound Energy.

We have also made a full license and training available to OPUC staff to ensure that our modeling and analytical processes remain transparent and open to critical review. We expect the Aurora model to provide us more detailed insights about our portfolio mix and the risks we face in making future resource decisions, due to its hourly granularity and regional unit-commitment modeling capabilities.

After we run our power cost estimates in Aurora, we will then enter them into our Transition Cost Model (TCM), which is the modeling tool we used in our 2002 IRP. The TCM will merge the power cost estimates with the expected fixed and capital costs of the trial portfolios and existing resources, and calculate the long-term cost of the trial portfolios based on the net present value of revenue requirement (NPVRR).

We will then assess the cost of the candidate portfolios under deterministic and stochastic assumptions for fuel and electricity. We will also evaluate a few long-term scenarios such as critical hydro and a high CO_2 tax, and rank the portfolios by cost and risk. Finally, based on these results we will propose and discuss with our stakeholders the best portfolios to meet our future needs.

FERC Standards of Conduct and Resource Planning

With the advent of the FERC Standards of Conduct (SoC), PGE finds it difficult to gather required transmission information to adequately assess related generation alternatives. On September 24, 2005, PGE joined with Puget Sound Energy in meeting with FERC staff to discuss the difficulties the SoC present regarding integrating transmission requirements into generating decisions.

On October 11, 2005, Chairman Lee Beyer of the OPUC also sent then-Chairman Joseph Kelliher of FERC a letter describing the issues in preparing an IRP under FERC Order 2004 due to the difficulty of obtaining adequate transmission information.

Chairman Kelliher acknowledged the potential barriers in some circumstances and suggested either possible organizational remedies or the possibility of requesting a limited waiver of the rules. PGE continues to assess which approach is likely to best provide needed transmission information and meet the goals of the IRP.

Timing of Next IRP

We intend to file our next IRP by the end of 2006. As presented above, we have already concluded many preparatory studies. Others are being launched or are well underway. We met with customers in March to discuss our future resource needs and the IRP process. We also plan to hold approximately six public meetings, one per month beginning in April, to discuss our research, analytical methods and findings, and to elicit responses from PGE stakeholders and interested parties. Our tentative schedule of meeting topics is listed below.

PGE's Load-Resource Balance, Scope of IRP, April 2006

- Introduction: cost, price stability, environment
- IRP Update *vs*. Final Action Plan
- Regional load-resource balance
- PGE load-resource balance
- Detailed work plan for evaluating the portfolio for least cost, risk, and diversity
- IRP studies
- Full stakeholder dialogue agendas
- Outline of 2006 IRP

Demand-Side Management & Externalities, May 2006

- Follow-up, open items from previous meeting
- ETO energy efficiency forecasts
- Customer outreach studies
- Demand response
- Combined heat and power

- Dispatchable Standby Generation
- Real time pricing rate design
- AMI update
- CO2 tax and PGE climate change policies
- RPS potential

Candidate Supply-Side Resources, June 2006

- Follow-up, open items from previous meeting
- Technologies
- Generic cost inputs
- Renewables
- Biomass
- Wave energy
- Wind integration
- Distributed nuclear (OSU)
- Coal technologies
- CO2 sequestration
- UW climate study

Fuels and Transmission, July 2006

- Follow-up, open items from previous meeting
- Fuels fundamentals
- Coal
- Emissions and environmental issues
- Transmission constraints and solutions, OSU studies

Candidate Plans, August 2006

- Follow-up, open items from previous meeting
- Candidate trial plans
- Issues and questions to be addressed in the IRP
- Distributions and correlations of stochastic inputs
- Modeling and analysis issues
- Risk metrics in models
- Diversity characteristics

Trial Plan Analysis, September 2006

- Follow-up, open items from previous meeting
- Trial plan results
- Stochastic results
- Sensitivity results

Conclusion

Since acknowledgement of the 2002 IRP Final Action Plan, PGE has focused on effective implementation to ensure congruence and continuity between our planning and procurement processes. As a result of these efforts PGE has now completed all targeted resource actions except the acquisition of an additional 38 MWa of wind energy. Negotiations to complete this remaining action are also nearly complete, at which point PGE will have in all material respects met the resource targets from our Final Action Plan. Throughout this implementation process PGE has remained mindful of changing conditions and vigilant to ensure that the resource actions taken continue to meet the objectives of the IRP.

PGE has further taken numerous steps to satisfy the conditions of the OPUC acknowledgement order related to transmission, demand response, energy efficiency and CHP resource potential. While some of our activities in response to these conditions will continue, we believe that our actions to date evidence PGE's fulfillment of the Commission's order in this area.

Finally, we also recognize that resource planning is a continuum with new resource needs emerging even as we complete the actions from our last IRP. As a result, PGE is currently in the process of launching its 2006 IRP, which we expect to file in December 2006. Initial results of our load-resource balance assessment for the next IRP indicate that PGE will have material resource needs on a resource adequacy basis shortly after the end of this decade. We are further forecasting significant resource needs on an economic dispatch basis starting in 2007. Addressing these future needs will require consideration of many factors that affect risk and value associated with resource choices. Doing so will require robust research, analysis and an open dialogue with the many PGE constituents that are impacted by our resource decisions. We intend to remain focused on these objectives as we conclude our 2002 IRP Final Action Plan and move forward with our 2006 IRP. We look forward to working with the Commission and stakeholders as we prepare our 2006 IRP.

Appendix

- Joint letter to Oregon's delegation urging renewal of the PTC

Portland General Electric ▪ Puget Sound Energy ▪ PacifiCorp

NorthWestern Corp. ▪ Citizens' Utility Board of Oregon

Washington State Office of Community, Trade, and Economic Development

July 7, 2004

The Honorable Gordon Smith
United States Senate
404 Russell Office Building
Washington, D.C. 20510

Dear Senator Smith:

We are writing to thank you for your continued support of the Production Tax Credit (PTC) for renewable energy, and to ask for your assistance in refining the PTC provision included in the House and Senate FSC/ETI bills during the conference process. Your continued active engagement will be essential in ensuring that the final bill addresses the needs of Northwest renewable energy stakeholders and electricity customers and in providing much-needed economic development and job creation for the Northwest.

The expiration of the PTC on Dec. 31, 2003 — and continuing uncertainty about the duration and form of any extension — have virtually halted new renewable resource procurement in the Northwest. The lack of a PTC has put the renewable energy resource procurement plans of the four Northwest utilities signing this letter in a "holding pattern." To allow Northwest utilities to follow through on their resource acquisition plans, the PTC must be extended at least until January 1, 2007 and must include the inflation index provision that is in current law.

Given the uncertain schedule for enactment the FSC/ETI legislation, extension of the PTC through 2005 as contained in the House bill would not deliver a robust renewable energy portfolio for the region. Utilities must complete negotiations for projects, developers must obtain the necessary turbines and construction and commissioning must be completed for projects to qualify for the credit. At this point in time, some projects contemplated by utilities and developers could not practically be placed in service by December 31, 2005. Further, continuation of the inflation adjuster provision is a critical factor in making wind projects more cost competitive for utility consumers.

PacifiCorp, Portland General Electric, Puget Sound Energy and NorthWestern must acquire new generation resources in the near future to meet the growing needs of their customers. These utilities want to add renewable resources – particularly wind power – to their respective power supply portfolios because, with the PTC, wind is increasingly cost-competitive with other new resources, such as gas and coal fired generation. Wind power also acts as an important hedge in utility portfolios against the risk of fuel price volatility and further environmental restrictions on thermal generation. With the PTC, investment in wind resources creates a rare confluence of good energy policy, good environmental stewardship, and good economic opportunity for the region.

In closing, we again thank you for your continued support for this critical issue and we hope to continue to work with you to gain timely extension of a PTC through 2006 as well as to maintain an inflation adjuster.

Best regards,

Peggy Y. Fowler

Peggy Y. Fowler
CEO & President
Portland General Electric

Stephen P. Reynolds

Stephen P. Reynolds
President & CEO
Puget Sound Energy

Judi Johansen

President & CEO
PacifiCorp

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Jason Eisdorfer
Energy Program Director
Citizens' Utility Board of Oregon

Tony Usibelli
Director, Energy Policy Division
Washington State Office of Community, Trade, and Economic Development