Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● jog@dvclaw.com
Suite 450
1750 SW Harbor Way
Portland, OR 97201

September 28, 2018

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC CO.
2018 Request for a General Rate Revision
Docket No. UE 335

Dear Filing Center:

Please find enclosed the Cross-Examination Exhibits of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

The confidential portion of AWEC's cross-exam exhibits is being handled in accordance with Order No. 18-047 and will follow to the Commission via Federal Express.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosure

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **confidential portion of AWEC's Cross-Exam Exhibits** upon the parties shown below by mailing copies via First Class U.S. Mail, postage prepaid, and by sharing via the Huddle workspace in this docket.

Dated at Portland, Oregon, this 28th day of September, 2018

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

CITIZENS' UTILITY BOARD OF OREGON
Robert Jenks **(C)**
Michael Goetz **(C)**
610 SW Broadway, Suite 400
Portland, OR 97205
bob@oregoncub.org
mike@oregoncub.org

SMALL BUSINESS UTILITY ADVOCATES
Diane Henkels **(C)**
Cleantech Law Partners PC
420 SW Washington St., Suite 400
Portland, OR 97204
dhenkels@cleantechlaw.com

FRED MEYER
Kurt J. Boehm **(C)**
Jody Kyler Cohn **(C)**
Boehm, Kurtz & Lowry
36 E. Seventh St., Suite 1510
Cincinnati, OH 45202
kboehm@bkllawfirm.com
jkyler@bkllawfirm.com

WAL-MART
Vicki M. Baldwin **(C)**
Parson Behle & Latimer
201 S. Main St., Suite 1800
Salt Lake City, UT 84111
vbaldwin@parsonbehle.com

PUC STAFF - DEPARTMENT OF JUSTICE
Stephanie S. Andrus **(C)**
Sommer Moser **(C)**
PUC Staff – Dept. of Justice
Business Activities Section
1162 Court St. NE
Salem, OR 97301-4096
stephanie.andrus@state.or.us
sommer.moser@doj.state.or.us

PORTLAND GENERAL ELECTRIC COMPANY
Stefan Brown **(C)** 1WTC-0306
Douglas Tingey **(C)** 1WTC-1301
121 SW Salmon
Portland, OR 97204
stefan.brown@pgn.com
doug.tingey@pgn.com

CALPINE ENERGY
Gregory M. Adams **(C)**
Richardson Adams, PLLC
P.O. Box 7218
Boise, ID 83702
greg@richardsonadams.com

WAL-MART
Steve W. Chriss **(C)**
Wal-Mart Stores, Inc.
2001 SE 10^{th} St.
Bentonville, AR 72716
stephen.chriss@wal-mart.com

CALPINE ENERGY
Kevin Higgins **(C)**
Energy Strategies LLC
215 State St., Suite 200
Salt Lake City, UT 84111-2322
khiggins@energystrat.com

NORTHWEST & INTERMOUNTAIN POWER PRODUCERS COALITION
Irion Sanger **(C)**
Mark Thompson **(C)**
Sanger Law PC
1117 SE 53^{rd} Ave
Portland, OR 97215
irion@sanger-law.com
mark@sanger-law.com

OPUC STAFF
Marianne Gardner **(C)**
OPUC
P.O. Box 1088
Salem, OR 97308-1088
marianne.gardner@state.or.us

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 335

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.	CROSS-EXAMINATION EXHIBITS OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS

Pursuant to the Administrative Law Judge's Ruling dated August 14, 2018, the Alliance of Western Energy Consumers ("AWEC") submits the following cross-examination exhibits for the direct access portion of this docket.

AWEC has one cross-examination exhibit for the Oregon Citizens' Utility Board ("CUB").

Cross-Examination Exhibit	Description
AWEC/600	CUB response to AWEC Data Request 002 and attachments

AWEC has seven cross-examination exhibits for Portland General Electric Company ("PGE")

Cross-Examination Exhibit	Description
AWEC/601	Excerpt from PGE 2016 IRP showing forecasted capacity need
Confidential AWEC/602	PGE response to AWEC Data Request 155 and Confidential Attachment A
AWEC/603	PGE response to AWEC Data Request 156

DAVISON VAN CLEVE, P.C.
1750 SW Harbor Way, Suite 450
Portland, OR 97201
Telephone: (503) 241-7242

Cross-Examination Exhibit	Description
AWEC/604	PGE response to AWEC Data Request 158
AWEC/605	PGE response to AWEC Data Request 157 and Attachment A
AWEC/606	PGE response to AWEC Data Request 160
AWEC 607	Table 1 from page 11 of AWEC/500 with alternative assumptions

AWEC has conferred with both CUB and PGE and understands that both parties are willing to stipulate to the admission of the above-referenced exhibits

Dated this 28th day of September, 2018

Respectfully submitted,

DAVISON VAN CLEVE, P.C.

/s/ Tyler C. Pepple
Tyler C. Pepple
1750 SW Harbor Way, Suite 450
(503) 241-7242 (phone)
(503) 241-8160 (facsimile)
tcp@dvclaw.com
Of Attorneys for the
Alliance of Western Energy Consumers

Oregon Citizens' Utility Board

610 SW Broadway, Suite 400
Portland, OR 97205

(503) 227-1984
www.oregoncub.org

September 14, 2018

TO: Jesse O. Gorsuch
Davison Van Cleve PC

FROM: Oregon Citizens' Utility Board

RE: UE 335 AWEC's First Set of Data Requests to CUB

PORTLAND GENERAL ELECTRIC
UE 335
CUB Response to PGE Data Request No. 2
Dated September 14, 2018

Data Request

2. Reference CUB/400 at 3:25-26. Please provide all documents and other evidence in CUB's possession that demonstrate that an expectation of continued load growth influenced the formulation and consideration of transition charges in PGE's long-term opt-out program.

Data Response

2. See attached zip folder for the requested documents in CUB's possession.

Future Demand Growth

Table 6-4 shows the range of demand growth in our service area between 1994 and 2015. The average megawatt projections were based on "frozen efficiency" assumptions and calculated at customer meters.

Table 6-4. PGE Service Area Demand Growth[1]
(MWa)

Low Growth	Medium Low	Moderate	Medium High	High Growth
200 MWa	660 MWa	1,000 MWa	1,240 MWa	1,760 MWa

[1]As measured at customer meters; 7% higher at the bus bar

Over the next two decades, we forecast that market demand for electricity will grow from a low of 200 MWa at the customer meter (before transmission and distribution losses) to a high of 1,760 MWa. It is more likely, however, that demand growth will fall between 650 MWa and 1,240 MWa with equal chance of occurrence throughout this range. The moderate growth future suggests a 995 MWa increase. Figure 6-5 depicts demand growth by individual segments through 2015 for all futures. The commercial market is expected to grow the fastest under all scenarios.

Residential Market

In 1994, the residential sector accounted for 40 percent of the retail electricity market. Of that, 25 percent was for space heating, 23 percent for water heating, 18 percent for refrigeration and 34 percent for lights and other appliances. We project residential demand to grow by almost 260 MWa (measured at customer meters) in the next two decades in the moderate growth future (see Table 6-5). In the high growth future, demand by residential customers could grow as much as 530 MWa. As was the case with recent trends, we expect significant shares of projected growth to come from appliance use.

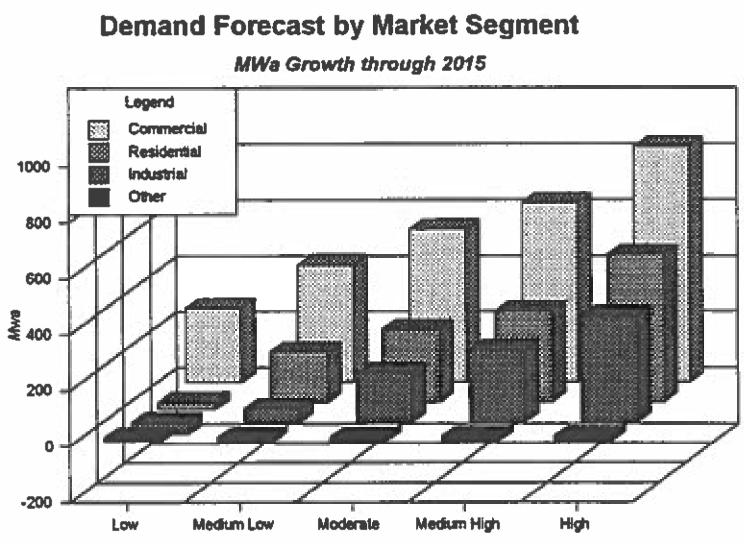

Figure 6-5

Table 6-5. Projected Growth in the Residential Market By End-Use: 1994-2015[1] (MWa)

End-Use	Low	Medium-Low	Moderate	Medium-High	High
Space Heat	-10	12	26	39	89
Water Heat	-31	-9	3	14	65
Appliances	16	176	230	271	371
Total	**-25**	**179**	**259**	**324**	**525**
'94-'15 AARG	-0.1%	1.0%	1.4%	1.7%	2.5%

[1]At the point of use.

We expect demand growth in the residential market (Table 6-6) to be driven by the increasing number of customers, more than offsetting the lower use per customer, which results from more efficient home appliances (1993 federal standards) and structures (1992 Oregon codes) and from an increasing share of multifamily dwellings which consume less energy relative to single-family homes. Most of the growth in space heating should come from the multi-family market, where zonal heating systems remain most cost-effective. Low penetration of electricity as a heating fuel in the single-family market and conversion of water and space heaters from electricity to gas should reduce the demand for electricity. These declining usage trends will dominate and offset factors that increase household energy use, such as continuing accumulation of electric home appliances, construction of larger dwellings and, eventually, introduction of the family electric cars. In the medium-high and high scenarios, the share of electricity in new home heating was assumed to increase and the gas conversion rates to decline over time. The reverse was assumed for the low and medium-low scenarios.

Table 6-6. Sources of Growth in the Residential Market 1994 - 2015 (% of Average Annual Rate of Growth)

Factor	Low	Medium-Low	Moderate	Medium-High	High
No. of Customers	0.8	1.2	1.6	1.9	2.4
Use per Customer	-0.9	-0.2	-0.2	-0.2	0.1
Residential Total	*-0.1*	*1.0*	*1.4*	*1.7*	*2.5*

Commercial Market

The commercial (non-manufacturing) sector is our second largest retail market, currently accounting for 35 percent of total retail sales. Twenty years ago it accounted for less than 25 percent of retail sales. This market has been growing the fastest in recent decades (4.6 percent annually *vs*. 2.7 percent for total retail in the last 20 years), benefiting from the secular transition to a service economy, urbanization of the service area and increasing demand for health, business and personal services. We expect this trend to continue at a slower pace for all scenarios in the next two decades.

PORTLAND GENERAL ELECTRIC CO.

1998-1999 Integrated Resource Plan

September 1, 1997

Columbia Hills Project

In early 1992, Puget Power short-listed Kenetech (then US. Windpower) for the supply of up to 50 MW of wind power from a project sited near the Rattlesnake Hills (northwest of Richland WA). In an effort to spread the risk and cost of acquiring a wind project, Puget invited other Northwest IOUs to participate in the project. PacificCorp, PGE and Idaho Power agreed to participate with each party taking a 25% share of the project. Kenetech was responsible for developing, permitting, and constructing the project. Project ownership would be transferred to the participating utilities following performance testing.

Several problems were identified during the Rattlesnake Hills permitting process. Portions of the site were located on sacred Native American burial grounds. Some citizens viewed Rattlesnake Hills as a unique local landmark and wanted to preserve it. A required Environmental Impact Statement on the portion of the site located on federal property threatened to delay project development by several years. In response to these problems, Kenetech decided in the summer of 1993 to move the project from Rattlesnake Hills to a new site at Columbia Hills (east of the Dalles on the Washington side of the Columbia River).

Avian impacts became a major issue as the permitting process for the Columbia Hills site proceeded. PGE became increasingly concerned with the undefined consequences of incidental takes. Kenetech failed to allay PGE's fears. Environmental organizations such as the Columbia Gorge Audubon Society began to actively oppose the project.

Idaho Power withdrew from the project shortly after it was moved to Columbia Hills. Puget withdrew in January 1995. The Columbia Hills project was listed in PGE's 1995-1997 LCP as a 12.5 MW renewable project.

In February 1995, PGE and PacificCorp executed Project Development Agreements with Kenetech. These agreements were contingent upon Kenetech satisfying certain conditions contained in an avian side letter to the Agreement. In September 1995 US Fish and Wildlife issued its Biological Opinion on the avian impacts. After extensive review of the Biological Opinion, PGE concluded that Kenetech had failed to satisfy the avian side letter conditions. PGE notified Kenetech in January 1996 that it was terminating its participation in the project.

During the next several months, PGE and Kenetech worked together to see if the project could be restructured in a way acceptable to all parties, but these efforts proved unsuccessful. Kenetech also failed to deliver a "letter of credit" called for under the contract. PGE's Acknowledged/Updated 1995 LCP stated that the Columbia Hills Project was being terminated because the developer had not been able to comply with the contract terms. Kenetech subsequently filed for Bankruptcy on May 29, 1996.

Renewable Projects Discussed in Previous LCPs

1. **Columbia Hills - Wind**

2. **Pueblo Valley (Borax Lake) - Geothermal**

3. **Vansycle Ridge - Wind**

Columbia Hills

1. **Rattlesnake Hills Project Short-listed by Puget in RFP**

   Joined by PGE / Other IOUs

2. **Project Moved to Columbia Hills.**

3. **Project Shown As Resource in PGE's 1995 LCP**

4. **Development Agreements Executed in Feb 1995**

   Contingent on Satisfying conditions in avian side letter

5. **Kenetech Fails to meet Contract Conditions.**

   PGE Terminates Participation

   Reported in Acknowledged/Updated 1995 LCP.

Pueblo Valley

1. PGE's 1992 LCP called for Utilizing a RFP to Acquire Socially Responsible, Cost-Effective Renewable Resources

2. Renewable RFP issued in June 1993

   Pueblo Valley One of 5 Short-Listed Resources

3. PGE was Concerned with the Project's Ability to be Permitted

   MOU Required a Public Process

4. Message from the Public Process

   The Project Faced Strong Opposition from the Enviromental Community & was Unlikely to be Successfully Developed

5. PGE Ceased Negotiations with the Developer

   Decision Reported in 1995 LCP

Vansycle Ridge

1. **PGE's 1992 LCP called for Utilizing a RFP to Acquire Socially Responsible, Cost-Effective Renewable Resources**

2. **Renewable RFP issued in June 1993**

   Vansycle Ridge One of 5 Short-Listed Resources

3. **MOU in May 1995; Power Sales Contract in Sept 1995**

4. **Kenetech Filed for Bankruptcy in May 1996**

   Energy Unlimited Introduced to PGE

   Contract was Renegotiated Contract to Allow Assignment

   Zond Outbid Energy Unlimited (November 1996)

5. **Enron Purchased Zond in January 1997**

   Rights to Develop Vansycle Sold to ESI Energy

PORTLAND GENERAL ELECTRIC COMPANY
ONE WORLD TRADE CENTER
121 S.W. SALMON STREET
PORTLAND, OREGON 97204
(503) 464-7401

ALVIN ALEXANDERSON
SENIOR VICE PRESIDENT
GENERAL COUNSEL AND SECRETARY

September 2, 1997

The Honorable Roger Hamilton, Chair
The Honorable Ron Eachus
The Honorable Joan Smith
Oregon Public Utility Commission
550 Capitol Street, NE
Salem, OR 97310-1380

Dear Commissioners:

This letter accompanies PGE's 1998-1999 Integrated Resource Plan. This abbreviated plan recognizes the fundamental changes occurring in our industry. Our goal was to establish a transition strategy for energy efficiency and renewable resource development for the next two years.

Our plan establishes an energy efficiency strategy that will maintain our delivery capability levels at 1997 levels, and provide a bridge to a competitive environment in which energy efficiency funding is provided from a System Benefit Charge.

Our renewable strategy includes completion of the Vansycle Ridge wind project. We are also exploring opportunities for replacement of the Columbia Hills wind project. The proposed 22.5 MWa geothermal project in our merger-related Memorandum of Understanding may serve this purpose.

We look forward to your formal review of our 1998-1999 IRP and your acknowledgment of our Plan.

Sincerely,

Portland General Electric

1998-1999
Integrated Resource Plan

- Transitional Business Environment
- Planning Approach
- Integrated Resource Plan Update
- Two-Year Action Plan
- This Plan and the System Benefit Charge

September 2, 1997

For More Information

Kathy Phillips-Israel, Manager, Least Cost Planning
Rates and Regulatory Affairs Department
Enron/Portland General Electric Co.
121 SW Salmon St. (1WTC-0702)
Portland, OR 97204
(503) 464-7020

Table of Contents

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TRANSITIONAL BUSINESS ENVIRONMENT

Transitional Business Environment

This is Enron/Portland General Electric's Integrated Resource Plan for 1998-99. Here we present our objectives for implementing energy efficiency programs and acquiring certain renewable resources over the next two years, and describe a bridge designed to take us from today's regulated environment to a competitive future.

As we draft this Plan we operate as a single, fully regulated utility. At the same time we are preparing to enter a new world where our end-use customers will be allowed to select their energy providers.

We have signed a Memorandum of Understanding (MOU) with 14 public interest parties that describes our commitments to a variety of practices after our merger with Enron, restructuring and business separation.

The electric utility industry is becoming increasingly global and market driven. For example, as of January 1997, the Federal Energy Regulatory Commission (FERC) requires transmission providers to post available transmission capacity, prices and ancillary services on the Open Access Same-time Information System (OASIS). This system is an integral part of FERC's transmission service rules for open access, and all related business will be conducted through it. There, transmission customers can find the information they need to acquire energy services from competing providers. We participate in a regional OASIS site administered by the Bonneville Power Administration (BPA). Since this information became available, a futures market for electrical energy already has developed.

In 1996 the Oregon legislature considered a set of bills that would deregulate and restructure the electric industry and require full access for our customers by July 1, 1999. Although the Legislature did not reach consensus or pass a bill, the prospect of such a law added to the transitory nature of this planning period.

Another unknown in today's business environment is BPA subscription process. In response to the 1997 Comprehensive Review of the Northwest Energy System ("Comprehensive Review"), the BPA will legally separate its transmission and power generation functions, and take part in an independent transmission operating agency that serves the region. BPA markets the power generated at federal dams in the Columbia River Basin. Once its current power sale contracts expire in 2001, BPA will market energy by subscription. We do not know enough about BPA's subscription process today to include it in this Plan. For example, we do not know whether the subscription will cover general transfer agreements, or the commodity rate that BPA will charge. We will, however, closely follow the development of the agency's subscription procedure and incorporate it as appropriate in future planning.

Despite all of these uncertainties we intend to move forward, making a transition to a competitive environment. We want to lead the way in our own service territory with a Customer Choice introductory offer that demonstrate the advantages of direct access to our customers and energy service providers. We filed our direct access tariffs with the Oregon Public Utility Commission (OPUC) August 1, 1997, requesting approval by September 30 of this year. We would like to begin our demonstration for our large industrial customers immediately upon receiving the OPUC's approval, and start a similar program for residential and small commercial customers in selected areas on December 1, 1997.

During the merger proceeding we agreed to file with the OPUC a Customer Choice plan for our entire service territory within 60 days of the merger. We filed this plan in August 1997. It is in this Customer Choice Initiative that we describe how we propose to give our customers a choice of energy providers.

Modified Planning Requirements

Our 1995-97 Plan introduced the concept of signposts, which are actions or events that could cause us to reconsider planned or preparatory actions. Our flexibility to respond to changing conditions, or signposts, is an important principle of the Plan.

Rather than renew the full analysis represented in our 1995-97 Plan in an environment that left us wondering which future we should be planning for, we asked the OPUC to suspend the June 1997 filing of our 1998-99 Integrated Resource Plan and modify our planning requirements by substituting a modified requirement that recognized fundamental changes expected in our industry within the next two years.

In its Supplemental Order 97-215, the Commission granted our request to conduct an abbreviated planning process that focuses on developing energy efficiency and renewable resource targets and goals for 1998-99. With the OPUC's approval, we have prepared the plan before you today.

The 1998-99 Plan

In Portland General Electric's 1998-99 Integrated Resource Plan you will find a streamlined examination that reflects recent and anticipated changes in our business environment. Our discussion stays within the bounds of our least-cost planning, and leaves to other forums such issues as restructuring, separation of utility functions and direct access programs.

In the following sections you will find a discussion of our planning approach, followed by an update to the action items listed in our 1995-97 Plan. Next we describe our new, two-year action plan and, finally, tell how this Plan meshes with the proposed system benefit charge (SBC). You'll find a brief summary of each of these sections below.

Planning Approach

Our planning approach focused on items that needed updating since our 1995-97 Plan. At six public meetings we identified our energy efficiency and renewable resources goals for 1998-99. We took a look at the planning signposts laid out in the 1995-97 Plan to see what, if anything, may have changed, and then we established our planning assumptions for the 1998-99 Plan.

In the 1995-97 Plan, our analysis indicated a set of conditions under which we could continue to rely on the market for our incremental resource needs. These conditions are:

- Reserve margins remain at 15 percent or more in the Western Systems Coordinating Council (WSCC) region
- Moderate load growth in our service territory
- Gas prices remain within our projected range

These conditions still exist, indicating that it is prudent to continue to rely on the market for our incremental resource needs during our transition to a competitive, direct-access market. However, we see value in establishing new energy efficiency goals as a part of our bridge to working in a competitive environment within the terms of the MOU.

Our planning assumptions focused on energy efficiency. PGE's December 1996 avoided cost filing showed that electricity costs dropped between 1995 and 1996. Lower avoided costs indicated that energy efficiency targets for 1998-99 should be re-examined. In today's plan we show a decrease in the 20-year economic potential of energy-efficiency acquisitions from 265 MWa to 255 MWa.

Integrated Resource Plan Update

In our 1995-97 Action Plan we listed a number of action items and, today, we are sharing the results we've achieved to date.

- We find it both prudent and economical to fill our supply needs through purchases on the open market.
- We continue to monitor the cost-effectiveness of our existing energy-producing assets, and to take the necessary steps in obtaining permits and conducting engineering studies that we would need should it become prudent for us to repower certain existing plants or build new ones. Today we propose neither to build nor to repower, however, because of the opportunities available on the open energy market.
- Our ongoing hydro efficiency improvements continue from the 1995-97 Plan.

- We are in the process of relicensing three hydro projects, and assume that all five of our hydro facilities will continue to be available resources.
- We currently have one active renewable resource development project—Vansycle Ridge, designed as a 24.9 MW (7.5 MWa) facility.
- We exceeded our energy-efficiency goals for both 1995 and 1996, acquiring a total of 28.22 MWa in energy savings for those two years. Our work continues as defined in the 1995-97 Plan in both the new and existing markets for residential, commercial and industrial customers. We continue to include a strong emphasis on transforming these markets to more energy-efficient products and practices.
- We continue to make the transmission and distribution system upgrades that make technical and economic sense, while deferring work that is not necessary for the safe, reliable and economical operation of our system.
- We continue to monitor our signposts and work with the OPUC to take any regulatory actions necessary to help ensure an efficient, responsive planning process.

Two-Year Action Plan

Finally, we propose a 1998-99 Action Plan that describes new goals in energy efficiency and renewables. In energy efficiency, we will maintain our program delivery capability level, even though savings acquired may decline. We also show actions that go beyond traditional planning requirements as a bridge to the SBC which, when implemented, would result in higher spending for energy efficiency. We set a goal of 5.91 MWa for 1998, and 6.18 MWa for 1999, with budgets of $12.1 million and $12.3 million, respectively. The budget for potential bridge actions is an additional $1.6 million in unallocated funds in 1998, and $1.4 million in 1999, for additional cost-effective energy savings.

Vansycle Ridge will be our sole renewable resource within this Plan, and we also will explore alternatives to the Columbia Hills project.

We will continue to monitor the signposts discussed in our 1995-97 Plan and, when we believe action is indicated, submit the appropriate documents to the OPUC.

This Plan and the System Benefit Charge

A new element in our plan is the concept of a bridge action plan, intended to allow a smooth transition from today's regulated environment to a competitive future. We expect that funding for energy efficiency and renewable resources will change from today's method of utility funding. The Comprehensive Review recommended that a regional SBC be adopted for funding energy efficiency and renewable resources. The recommendation was that the SBC be non-bypassable and, when aggregated regionally, would equal 3 percent of the region's sales revenues. Although an SBC has not yet been implemented, our Two-Year Action Plan identifies a number of bridge action items that are intended to prepare us for the future.

We support an SBC, and to make sure we are aligned with issues we expect to arise during this transitional period, we have increased the pace of our energy-efficiency resource acquisitions beyond our original proposal. As a result, our investments in this area will be closer to what they will be with an SBC.

Planning Approach

Our approach to this plan was to focus on items that needed updating since our 1995-97 Plan—energy savings through efficiency measures and development of renewable resources.

Because we concentrated on selected areas, we required only a short public process to identify energy efficiency and renewable resources goals for 1998-99. We held six public meetings attended by representatives from the OPUC, several public interest groups and the electric utility industry.

- *June 5, 1997.* We discussed our transition to a competitive marketplace, and laid out our IRP process and schedule. We looked at current load and power market conditions. Finally, we introduced our current energy efficiency supply curve, summarized current energy efficiency activities and described our involvement with the Northwest Energy Efficiency Alliance (NEEA), a regional collaborative chartered to implement energy efficiency market transformation.
- *June 18.* We updated key supply-side activities. We then described our planning assumptions and compared them with a potential SBC. Then, after an update of our energy efficiency supply curve, we presented and discussed PGE's strawman energy efficiency goals and planning assumptions for the 1998-99 Plan.
- *June 26.* A sub-group from our Public Meeting attendees met to discuss avoided cost assumptions.
- *July 8.* The avoided cost sub-group met again to continue their discussion. We revised some of PGE's assumptions, and slightly changed our avoided cost estimates.
- *July 9.* We presented the avoided cost assumptions that we revised based on the technical meetings, and responded to comments received at the June 18 meeting with revised energy efficiency targets. We updated the status of BPA's subscription process and residential exchange processes, and our role in the Centralia coal generation plant. We then focused on renewable resources, beginning with an update of the Pueblo Valley, Columbia Hills and Vansycle Ridge

projects, of which only the latter remains active. Finally, we reached consensus on how to represent our renewable resources strategy in the Plan.

- *July 15*. Interested participants attended a half-day technical discussion of energy efficiency issues. We agreed to a two-year action plan for energy efficiency that will maintain PGE's activity level, but not targets, at 1997 levels.

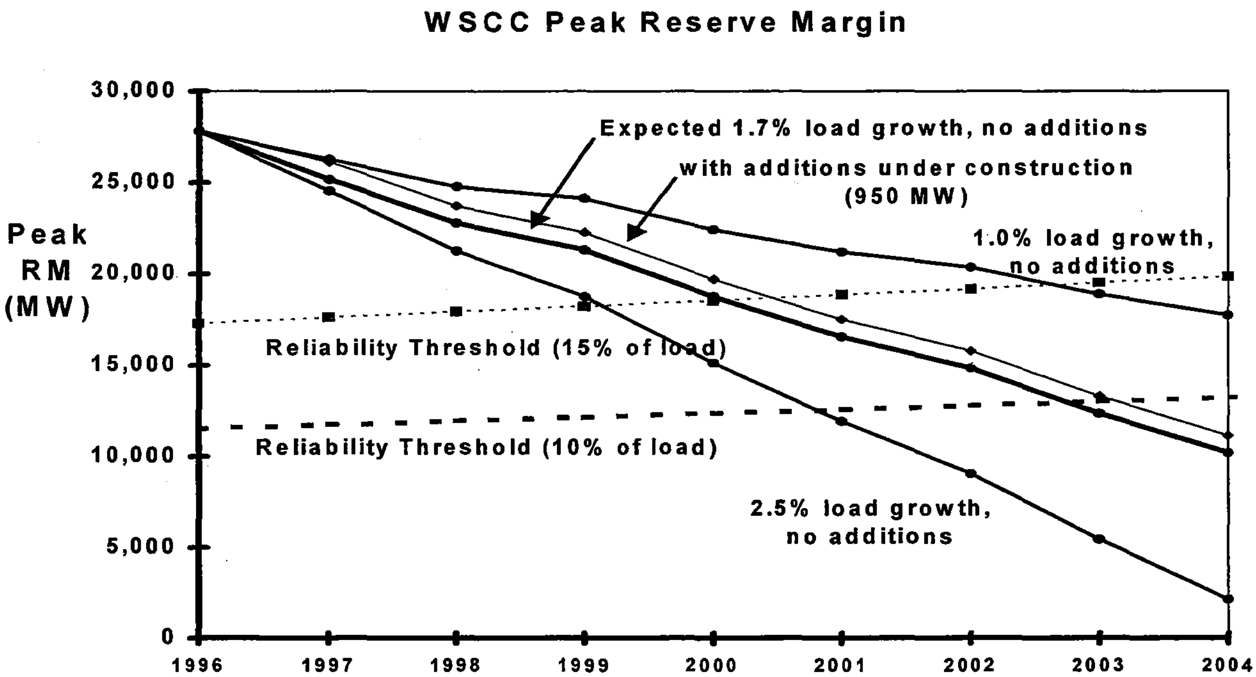
Evaluation of Signposts

We plan to continue relying heavily on the market for the energy our customers require. In our 1995-97 Plan we described planning signposts in terms of a series of forecasting cases:

- Market-Related Cases No. 1-5
- Fuel-Related Cases No. 6-10
- Externality-Related Cases No. 11-16

As discussed on the following pages, little has changed in the power market since then to alter our course.

We follow our review of the signposts with an update on our economic potential analysis for energy efficiency measures, and lay out the assumptions for energy savings and renewable resources on which we base this Plan.



Market-Related Cases No. 1-5

The demand forecasts developed in our 1995-97 IRP have proven to be accurate. We forecasted a five-year growth rate of between 0.7 and 3.5 percent for the immediate five-year period, with a 2.5 percent growth rate as the Moderate Case. For the 20-year period we projected a range of growth rate between 0.6 and 3.1 percent, with a 2 percent annual growth rate for the Moderate (Middle) Case. Firm demands have been within the forecast boundaries, and they are on target with the Moderate path since 1994. However, demands fell below the Medium-Low (1.9 percent) path for 1996, in part because of outages caused by floods and windstorms and due to one particular large industrial customer's special circumstances. Firm sales grew at less than 0.9 percent in 1996 and 1.5 percent if adjustments to these special circumstances were made. Demands have grown at 2 percent in the past four years. We expect demand to return the Moderate path in 1997.

Residential Sector Demand. Demand in this sector followed the forecasted Medium-Low path, dropping below it in 1996 due to outages, rather than the Moderate path we had originally expected. Residential demand grew only 1.5 percent a year in the past four years, below the projected 1.9 percent Moderate path, but were within the 0.1 percent to 2.8 percent projected boundaries. One of the reasons that demand growth was lower than expected in the Medium case was a faster drop in the average energy use per household and a faster growing share of multifamily customers. The outages also contributed to a sharp drop in use in 1996. We expect residential demand in 1997 to pick up and return to the Moderate growth path.

Commercial Sector Demand. Demand for commercial customers grew as expected, about 3 percent annually in the last four years. We had projected a range of 1.2 percent to 4 percent annual growth rate for demand in this market, with the Moderate path to grow at 3 percent a year.

Industrial Sector Demand. Industrial demand fell in 1996 due to weather-related outages and closure of one paper mill. As a result, demand fell to the Low Growth path in 1996. In the last four years, industrial demand grew only 1.2 percent a year, significantly lower than the 2.4 percent growth rate projected for the Moderate path. We expect demands to rebound in 1997-99 period as high technology projects continue to be filled in and a new owner has reopened the paper mill shut down in 1996. We had projected this market to grow between 1.1 percent and 4 percent a year in our 1995-97 Plan.

Fuel-Related Cases No. 6-10

WSCC Peak Reserve Margin. For reliability and marketing purposes, our resources belong to a pool defined by the WSCC. We rely on this marketplace for the energy we provide our customers. The WSCC's reserve, or resources above load, is measured at their load peak, which occurs in August. In the 1995-97 Plan our signpost was a 15 percent margin within the WSCC territory. Under the most aggressive load forecast, which projects a 2.5 percent growth rate, we do not expect to find less than a 15 percent reserve margin until 1999 or 2000.

Our forecasts indicate that in later years, as loads increase and less efficient generation runs more frequently, new combined cycle combustion turbines (CCCTs) will become cost-effective. Our forecasts include transmission constraints that would limit access to other regions of the WSCC, and the effects of these constraints are reflected in our avoided cost calculations.

During public meetings, participants posed two questions pertaining to the prudence of PGE's continued reliance on the market for energy:

- Has PGE learned anything from last summer's transmission problems that would affect this strategy?
- Does PGE believe its winter requirements are reliably met by relying on the market?

Parties within and outside PGE have studied these issues. The consensus within PGE is that our conclusion to rely on the market is still sound. Although extreme situations can arise, our planners believe that building power plants or major transmission facilities to address problems associated with transmission reliability or winter peaking is not appropriate. Reliance on the market, coupled with more cost-effective contingency measures, is the appropriate response to such possibilities.

The difficulty with the transmission system last summer was due to large north-to-south exports of Pacific Northwest energy to the Pacific Southwest and Desert Southwest. Our critical period in the Northwest, however, is the wintertime. Further, *south-to-north* transfers have not historically been curtailed to any significant extent, and we do not expect them to be. Moreover, the interruptions were caused when WSCC member utilities operated portions of the system outside of what we would, today, consider prudent limits. Interruptions from those systems cascaded onto the Intertie. The WSCC has subsequently reviewed its guidelines, and WSCC members have changed their operating procedures to assure sufficient operating reserve. Today, there is no reason to believe that the 1996 failure will repeat itself.

With regard to the second question, regional winter peak reliability problems may indeed be developing in the next several years. The Pacific Northwest Utilities Conference Committee (PNUCC), Northwest Power Pool (NPP) and PGE all have looked at the issue of the reliability of the system under winter load conditions. The NPP last examined the issue in October 1995 for the 1995-96 winter. Because of the good hydro conditions, a similar study was not performed on the 1996-97 winter. PNUCC, in their November 1994 report, "Assessing Northwest Capacity," and the Northwest Power Planning Council (NWPPC), in their March 1996 publication, "Northwest Conservation and Electric Power Plan," studied the issue from a more long-term perspective.

The long-term views suggested that a peaking problem is developing, although neither study suggested when peaking might become an issue for the Pacific Northwest. These studies found that imports would become progressively important to supporting expected energy deliveries, but did not consider special remedial action such as dropping load or deep-drafting reservoirs to generate additional power for cold snaps.

The NPP concluded that the 1995-96 winter system would be quite reliable. "The bottom line," their report concludes, "is that the system appears to be able to meet loads with a high level of reliability."

Our own transmission planners recognize that conditions could arise under which we may need to take special remedial action. Rather than commit to capital-intensive construction projects such as new transmission lines or power plants, however, our first line of response would be to drop interruptible load, draft reservoirs deep, and take other actions outside the assumptions of conservative planing models. Approximately 200 MW of interruptible load is currently available. PGE also has measures in place to quickly restore curtailed customers should load shedding or disconnection from the other WSCC regions occur. PGE views the development of additional interruptible load and means for more quickly restoring customers as important resources for meeting our reliability needs.

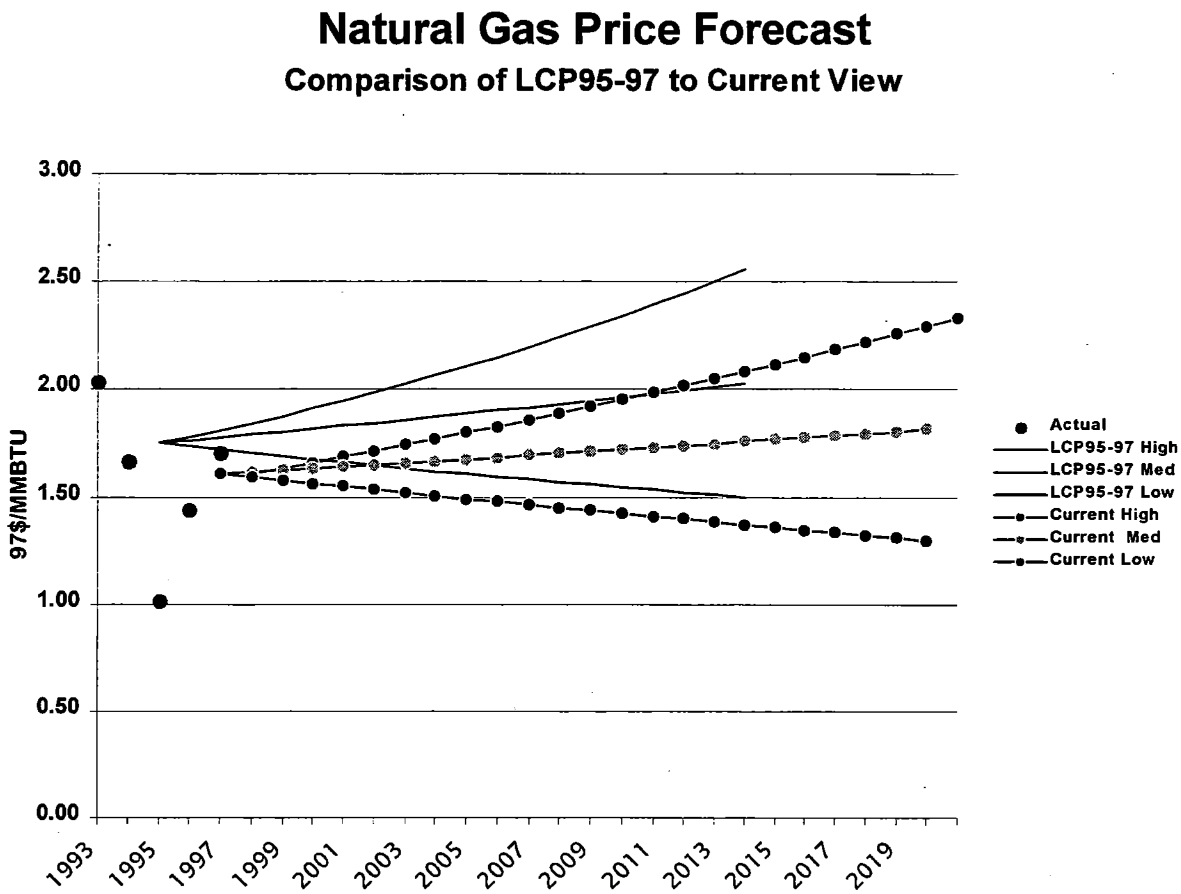
New regional organizations are emerging that may, at a future date, enhance the system's efficiency. For example, more than 20 utilities and public agencies, including PGE, have signed a memorandum of understanding to cooperate in studying the feasibility of forming IndeGO, an independent transmission grid operator (IGO). This IGO is intended to establish non-discriminatory open access to electricity transmission facilities, among other objectives. One could infer that the emergence of such cooperative efforts suggests a utility trend toward relying more on the market to meet energy requirements. However, it would be premature to include the potential efficiencies offered by such initiatives in this Plan. The potential members of IndeGO, in particular, are still defining that consortium'' identity, role and procedures.

Natural Gas Price Forecast. In our 1995-97 Plan we forecast high, medium and low gas prices. The following graph compares our forecasts for delivered gas with those used in the 95-97 Least Cost Plan. We have also included actual prices for Sumas gas. These actual prices are without transportation to the PGE service area, which would add between 3 and 9 cents per million Btu (MMBtu).

We arrived at this forecast through the public integrated resource planning process. Forecasts appearing earlier in the process were based on details and arguments which, although important to PGE's internal decision making, proved irrelevant to this Plan and difficult to communicate. We therefore adopted the simpler approach we present here.*

* The gas price forecast presented at our June 5, 1997 public meeting contained actual data for 1997, including very high prices for past months that for fundamental reasons we believed would not be repeated. Prices for the rest of 1997 and next several years declined slightly according to currently traded prices, upon which PGE bases some operational decisions. These price behaviors turned out to be difficult to communicate. The trading prices need not appear economically rational to all parties. Beginning in 1998, we will use avoided costs for the purposes of acquiring energy-efficiency and complying with the Public Utility Regulatory Policies Act. The difference between a simple, straight-line projection from 1998 through the end of the forecast period and the original forecast was negligible in absolute terms and invisible

September 2 1997



For the 20-year period we relied on the Wharton Econometric Forecasting Associates (WEFA) Group's forecast of wellhead gas prices in Canada (Alberta), San Juan and the Rocky Mountain producing areas to develop a consistent set of natural gas prices at the burner tip for plants geographically distributed throughout the WSCC. Transportation fees were accordingly added to arrive at these burner-tip prices.

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compared to the underlying uncertainties in such a projection. For this Plan, therefore, we adopted the simpler projection.

WEFA forecasts Canadian natural gas prices to increase from \$1.18 per MMBtu in year 2000 to \$1.50 per MMBtu in year 2020 in 1996 dollars. They also projected San Juan gas to rise from \$1.57 per MMBtu to \$1.94 per MMBtu and Rocky Mountain gas from \$1.70 per MMBtu to \$2.02 from 2000 to 2020, respectively. For Sumas gas, we maintain, as we have in our 1995-197 Plan, that prices will fluctuate in a \$1.25 per MMBtu to \$2.25 per MMBtu range, and that \$1.75 per MMBtu is a reasonable mid-point price, in constant dollars. To obtain annual Sumas gate prices, we interpolated from the base year (1997) value to the end-of-period (2020) price. For base-year prices, we solicited offers from gas brokers for gas delivered at specific hubs and averaged them in with actual historical prices, obtained from the Gas Daily, at these hubs.

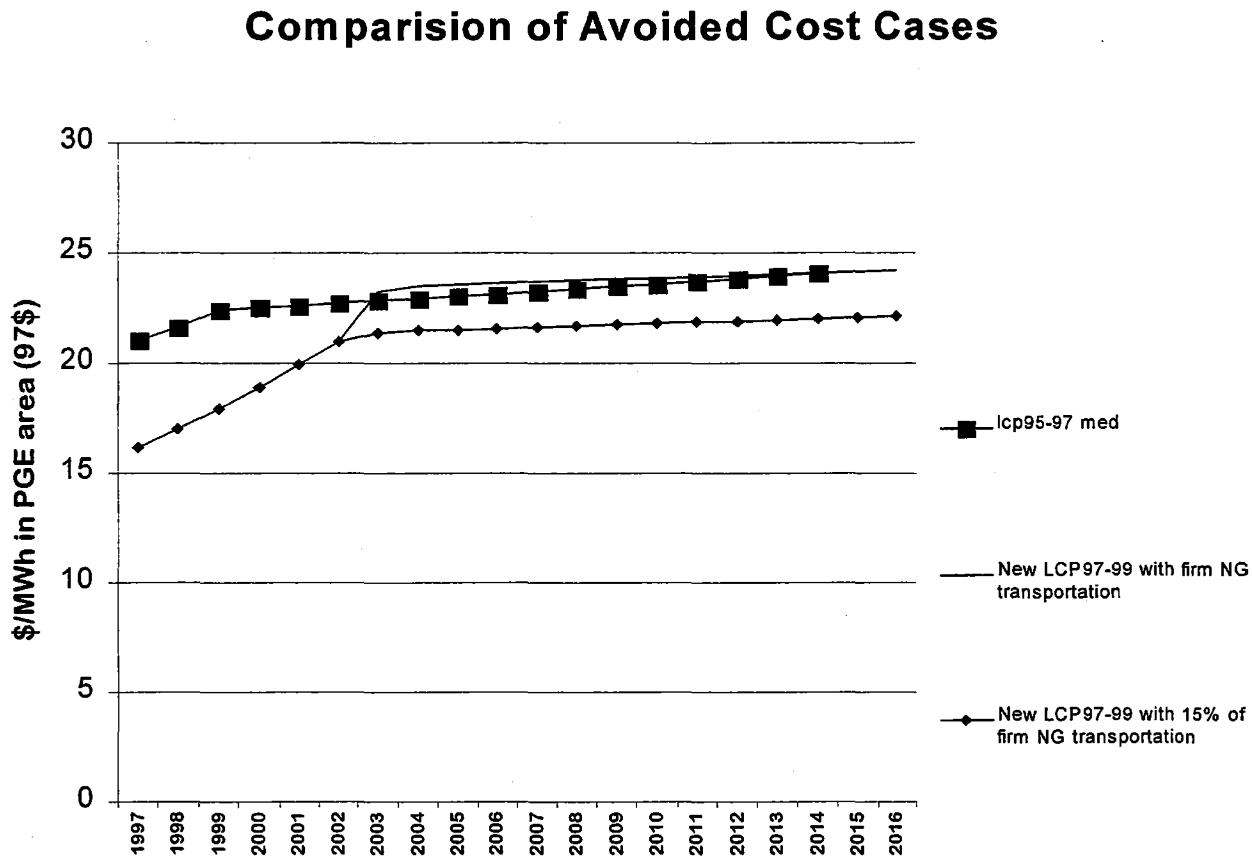
The \$1.25 and \$2.25 per MMBtu prices, in constant dollars, were used to set the low and high price boundaries for sensitivity analysis. We believe that prices below \$1.25 per MMBtu will discourage exploration and development, reducing the supply of gas and that a price above \$2.25 per MMBtu could not be sustained for long periods as it would bring on additional supplies competing for the same demand, thus driving down prices. Furthermore, at these high prices, substitutes such as oil or liquefied natural gas will cap natural gas price escalation.

During the public process, the natural gas projection was examined at a technical level by representatives of the Oregon Department of Energy, the OPUC and the NWPPC. One of the issues that arose during this examination was PGE's assumption regarding natural gas transportation. We had assumed early in the planning process that all purchases of natural gas would be made on the spot market, with non-firm transportation from the Canadian Sumas and AECO hubs in PGE plants averaging about \$0.07 per MMBtu in constant dollars in 1999, and increasing at a real rate of 1.3 percent. The question arose whether there should be some cost added to represent the fact that, eventually, new gas-fired power plants would either have to arrange for some firm transportation, market purchases, customer curtailment, or use of alternative, higherpriced generation during periods when gas transportation is curtailed. We agreed that some cost for firm transportation was appropriate, but because that cost is fixed as related to energy generation, it is not added to the variable cost projections for gas appearing in the preceding graph. Instead, it was modeled as an additional fixed cost of approximately $730,000 (1997$) annually for new gas-fired generation units. The additional annual cost is about 15 percent of the cost of firm, year-round transportation (without release back into the secondary transportation market). The firm, year-around cost serves as a upper limit on this fixed cost. The discount to 15 percent reflects the low probability of extended hours of curtailment and the availability of alternatives to firm, year-around transportation of gas.

The natural gas projections are a key driver behind our estimate of avoided cost. Expectations about natural gas price represent a principal source of uncertainty in the value of energy efficiency and renewable resources, which must compete on an economic basis with market purchases, cogeneration, conventional combustion turbines, and other sources of energy that rely on natural gas for generation.

Avoided Cost Forecast. To arrive at an avoided cost for PGE, we performed computer simulations of power production in the WSCC. The avoided cost is basically the market price of energy in the area of interest, in this case the PGE service territory. These simulations reflect knowledge about the operating characteristics of the WSCC's roughly 1,700 resources and transmission constraints.

We found that, in the 2000 to 2003 time frame, the cost of existing resources becomes excessive and new resources become cost-effective. That is, when market prices would rise above the fully allocated—fixed plus variable—cost of the least expensive new resource, it becomes cost-effective to build the resource. If the supply of this resource is unconstrained, the fully allocated cost of the resource serves as a ceiling on the avoided cost. Because of the low cost of natural gas in Canada and the Pacific Northwest, CCCTs are built in those regions until transmission constraints



become significant. As a consequence, the avoided cost for PGE is associated with new units constructed in the local region. We refer to these new units as our *avoided units*.

With this background, we see that the avoided cost forecast consists of two portions: one portion prior to the time that costs catch up with the fully allocated cost of the least expensive, dependable source of substantial electric generation, and another portion following.

The avoided cost we used in this Plan is below what we used in the 1995-96 IRP, as illustrated in the accompanying graph. The top line is the Medium case avoided cost from the 1995-97 Plan. The bottom line represents the current corresponding case. As mentioned, these effectively include transmission to our service territory. The avoided costs do not include distribution losses significant to the evaluation of energy efficiency, but those losses are included elsewhere in the evaluation of energy efficiency projects. The bottom line splits into two portions in the 2003 time frame, when local new generation dominates local market prices. The lower fork includes the effect of 15 percent of firm transportation for natural gas. The upper fork includes the effect of 100 percent of firm transportation and is provided to illustrate an upper bound for this effect.

A final issue about which public participants requested information was the effects of a carbon tax on avoided costs. CCCTs produce less carbon dioxide per unit of electrical energy than do coal-fired turbines. These plants, which serve as our avoided units, would be likely to remain as our avoided units if a carbon tax or trading credit program were to be imposed. Assuming a heat rate of 7,225 BTU per kWh heat rate for a CCCT, a nominal tax of $10 per ton would produce a nominal increase in the cost of generation of 4.3 mills per kWh.

This avoided cost projection serves as a key driver to the assessment of economic potential for energy efficiency projects. This evaluation is discussed in the section below, entitled Updated Economic Potential.

Externality-Related Cases No. 11-16

The externality-related cases in the 1995-97 Plan addressed possible scenarios dealing with carbon tax, high gas price, alternative energy efficiency strategies, and WSCC resource shortages. Present resources and externality costs are much the same as they were when that Plan was written. In particular, our reliance on the market for incremental resources are substantially the same as they were in 1995. As a consequence of these factors, we estimate that our analysis of externalities performed in the 1995-97 Plan still holds.

Planning Assumptions

While our evaluation of the planning signposts covered the market, fuel costs and reserves, and externalities, our planning assumptions focused on energy efficiency. We made a series of assumptions for the purposes of this transitional plan. Each assumption is based on the following principles:

- Use cost-effectiveness as our planning criteria for energy efficiency programs
- Continue to recover all of our energy efficiency investments through our rates
- Revisit energy efficiency when an SBC or direct access is implemented
- Focus on lost opportunities
- Work in cooperation with the NEEA to accomplish our market transformation goals in our service territory

For our energy-efficiency activities over the next planning period, our analysis showed that fewer measures were cost-effective than in the previous Plan. Based on updated avoided cost figures that compare the cost of acquiring energy through energy-efficiency programs to that of generating or purchasing energy, the economic potential in all markets has decreased.

Our discussion of renewable resources is based on the assumption that, while we will continue the Vansycle Ridge project, any new development will be contingent on recovering costs through an SBC. PGE's SBC is discussed in our Customer Choice Initiative.

Updated Economic Potential

The economic potential of the energy savings available in each market sector has decreased slightly from the 1995-97 Plan. We attribute the decrease to a lower avoided cost and, in a few sectors for a few measures, a saturation of the market already achieved in previous planning periods. Examples of the latter include market saturation achieved in our showerheads program, and the 1996 commercial building

Decrease in Economic Potential		
	MWa	% Decrease
Residential	7.1	9
Commercial	1.3	1
Industrial	1.6	2
Total Decrease	10.0	4

codes which now require energy efficiency measures we previously offered in our programs. Certain measures that were cost-effective in the 1995-97 Plan no longer are, while some commercial lighting measures now are cost-effective because of a decrease in price. As a result, the 20-year economic potential dropped from 265 MWa to 255 MWa, a difference of 10 MWa.

At our public meetings on energy efficiency we showed a total decrease in economic potential of 20.6 MWa. As a result of revisions to our avoided cost forecast, we have changed the decrease in economic potential to the level discussed above.

Residential

Measures that are no longer cost-effective in the residential market are:

- Clock thermostats in new construction
- High efficiency, replacement water heaters in existing multi-family dwellings
- Weatherization in homes built to code since 1978

Decrease in Residential Economic Potential		
	MWa	% Decrease
New	0.1	0
Existing	7.0	11
Total Decrease	7.1	9

The weatherization measures that dropped out were only marginally cost-effective in 1995. Our analysis shows that the market is an expensive one. In the single-family market, most residences should only require a few measures, making administration costs high on a per-home basis.

Commercial

PGE customizes its energy-efficiency programs to fit each application. While certain measures, such as chillers in schools, do not show a cost-effective economic potential based on a generic, average building model, they may qualify on an individual basis at the program level. The decrease in the economic potential in the *new* commercial market is caused by the following measures dropping out:

Decrease in Commercial Economic Potential		
	MWa	% Decrease
New	0.8	1
Existing	0.5	1
Total Decrease	1.3	1

- Programmable thermostats in schools
- Chillers in commercial buildings
- Heat pumps in medical buildings

- Motor controls and variable-speed drives (VSDs) in most applications

In the *existing* commercial market, a separate list of measures no longer are cost-effective.

- Programmable thermostats
- Heat pumps in schools
- Chillers in schools
- Vinyl curtains in warehouses
- VSDs

Industrial

The industrial measures that dropped out for the 1998-99 planning period both relate to motors:

- VSDs
- Motor controls for energy management systems

Decrease in Industrial Economic Potential		
	MWa	% Decrease
Motors	1.6	10
Lighting	0.0	0.0
Process	0.0	0.0
Total Decrease	1.6	2.0

Energy Efficiency Program Planning Assumptions

Based on the new economic potential levels described above, and our participation in regional market transformation programs, we have developed a set of assumptions that will drive the measures we offer in our energy-efficiency programs.

Residential

- Customers will continue to be eligible for weatherization measures.
- Our participation in NEEA and its regional market transformation projects, such as the LightWise CFL program, address the same market as our previous lighting program. Any efforts we make in this market, besides our support of NEEA, will be to enhance that coalition's efforts.

Commercial and Industrial

- Potential savings in industrial processes have declined because there is less construction in the high-technology field than we anticipated, and because we have limited effectiveness in influencing this industry. Decisions are made out of state, often out of country, on bases other than energy efficiency. We will continue our efforts in this market.
- We expect a decline from our projections in new construction due to the high standards for our Earth Smart program, which requires savings of 20 to 30 percent over code. A more moderate Custom Solutions option sets the standard at 10 percent over code for all measures except lighting, which carries a requirement of savings that exceed code by 20 percent. The Earth Smart program is also limited by its high front-end costs related to building design and consultation. Because the time from building design through construction can take several years, results may not be realized within a given program period.
- We anticipate focusing more on new commercial and industrial buildings, while offering greater flexibility, if less emphasis, in the existing market.

Market Transformation

- Our market transformation efforts will be based on NEEA's estimates for our service territory, and in some areas will be linked to our participation in the regional efforts of that consortium.
- We remain committed to moving all of our markets to more efficient practices and technologies as feasible.

INTEGRATED RESOURCE
PLAN UPDATE

1995-97 Integrated Resource Plan Update

Since we filed our 1995-97 Plan, our industry has begun to make significant changes. On the wholesale market, utilities, customers and energy providers all have begun to prepare for open access. In some states, open access programs already are under way. New energy markets are no longer defined by service territories, and new energy suppliers are eager to compete for their market share.

The recently completed Comprehensive Review, and national and state legislative initiatives propose to influence how utilities are separated and regulated. New markets emerge when customers gain the right to select their energy service provider. Here, also, new suppliers are eager to compete for customers once considered linked to a single, full-service utility.

The merger of PGE with Enron also is a new feature in today's landscape. We wrote our 1995-97 Plan as a fully regulated, single-fuel utility with a contiguous service territory. We expect that our future resource actions, and current integrated resource planning requirements, will change to accommodate the competitive environment.

Supply-Side Actions

Our supply-side update provides the current status of actions identified in our 1995-97 Plan. We currently plan to satisfy our incremental power needs through purchases in the marketplace.

Purchases

Action items from 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Purchase short- and intermediate-term firm energy from the wholesale market to achieve our reliability standards.*

Our firm energy purchases have adequately met our reliability requirements.

Make Economic Use of Our Existing Assets

Phases I and II of the Beaver Repowering

Action items from 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Complete preliminary engineering study.*
- *Prepare and submit any needed exemption requests or air permit modifications.*
- *Obtain any needed EFSC [Energy Facility Siting Council] and DEQ [Department of Environmental Quality] approvals.*
- *Where signposts indicate, file documentation and applicable studies with the OPUC before we proceed to construct and operate the plant.*

We have completed our preliminary engineering study, and the air permit amendment is in progress for repowering the Beaver Plant, which is a 500 MW facility with six combustion turbines (CTs) located near Clatskanie, Ore. Because our leases on the existing CTs expire in 1999, we are evaluating several options, including:

- Repowering the facility to improve efficiency. Under this option the output would remain at 500 MW, but the turbines would operate more efficiently, and emissions would be reduced. We could also maintain the existing CTs as simple cycle units that would extend peaking capacity to 850 MW.
- Extending the existing lease and operating the plant as it stands today.
- Replacing the facility with electricity purchased on the market after 1999.

The Beaver Plant does not have a site certificate because it was built before EFSC was established, and was exempted from subsequent EFSC certification requirements. EFSC has an abbreviated exemption process for such cases, and if we decide to repower the facility, we will initiate that process.

Although our lease suggests initiating new negotiations within a year of expiration, we already have begun this process. While it is likely that we will need to make a decision regarding the Beaver Plant within the 1998-99 planning period, we are not prepared to do so today. At the appropriate time, we will file an amended IRP or other documents with the OPUC as required to implement what we determine to be the most prudent steps for operating the Beaver Plant.

System Efficiency Improvements (If and As Economic)

Action items from the 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Hydro efficiency improvements (up to 70 MW, 5.1 MWa)*

Over the past several years we have replaced turbine runners at Oak Grove (both units), Faraday (two of five smaller units) and Bull Run (three of four units). We are now completing turbine runner replacement of three of the five units at River Mill. Because of the sequential loading of units at many plants, there are diminishing energy returns with each additional unit upgraded The less efficient units are run only when flows are high, sometimes only a few weeks a year. With the above replacements complete, our next lowest cost options for replacing turbine runners are at the following plants: Round Butte (one or more of three units), Pelton (one or more of three units), North Fork (one of two units) and Faraday (the large unit).

- *Boardman coal plant efficiency upgrade (estimate 37.6 MW for our share).*

The Boardman boiler upgrade will take advantage of margins available in some of the power generation equipment to increase plant output by 20 to 25 MW, and efficiency by about 0.5 percent, both at a very competitive cost. We will modify the boiler by adding heat transfer surfaces at selected locations, and have scheduled this work for the 1998 annual maintenance outage.

Take Other Supply-Side Actions to Prepare for the Future

Coyote Springs II

Action items from 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Provide notice to EFSC as required in the site certificate if the decision is made to build Coyote Springs II, or take the necessary actions to obtain a modified site certificate that allows construction to proceed at a later date.*
- *Where signposts indicate, file documentation and applicable studies with the OPUC before we proceed to construct and operate.*

In our 1995-97 Plan we discussed completing the second of two units at this Boardman, Ore. facility. Coyote Springs I is a 240 MW, CCCT facility built at a previously undeveloped site. Coyote II would be built at the same site as a shared facility, and would add another 240 MW. All permits for Unit II construction are in place, and our EFSC permit requires that, to avoid reapplying, we must complete work by September 1999. To maintain our options, we have initiated negotiations with a CT vendor, and provided notice to EFSC regarding Coyote II as required by our site certificate. We are in the process of evaluating our options for Coyote II based on our current economic projections. Pending the results of our evaluation and our negotiations with the vendor, we will establish the construction schedule and file the appropriate documents with the OPUC before proceeding.

Deer Island (a combustion turbine facility at the Trojan site)

Action items from 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Complete preliminary engineering.*
- *Where signposts indicate, file documentation and applicable studies with the OPUC and proceed to: submit notice of intent to EFSC; submit applications for site certificate to EFSC;*

submit application for a DEQ air discharge permit; construct and operate as determined by the signposts.

The Deer Island project would involve building a 240 MW, CCCT facility at the Trojan site on the Columbia River. We have submitted a natural gas safety analysis to the Nuclear Regulatory Commission (NRC) that evaluates the hazard potential of a gas-fired turbine on a site constructed for storing nuclear fuel. Our analysis shows that no safety hazard exists, and we expect the NRC's response by mid-1998.

We have not begun our preliminary engineering analysis, and we have no other active project development in progress today.

Hydro Relicensing

Action items from 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Provide a detailed discussion of the status of PGE hydro facility relicensing efforts in the next [1998-99] Plan.*

PGE holds 50-year licenses on five separate hydroelectric projects. We plan to reapply for three licenses and, for the purposes of the 1998-99 Plan, assume that all five projects will continue to be available resources. The following paragraphs summarize the current status of each project.

Pelton Round Butte, located on the Deschutes River in Jefferson County, is comprised of the 300 MW Round Butte facility, and the Pelton and Reregulating facilities that have a 108 MW capacity. This project operates under both a FERC license and two Oregon state licenses. Our relicensing activities are under way. We filed our Initial Consultation Document on July 6, 1996, held a public and agency meeting on Sept. 6, and filed a Notice of Intent Dec. 6 of the same year. We plan to pursue the reapplication process through the 1998-99 planning period.

Pelton Round Butte
FERC License No. 2030
Issued Jan. 1 1952, expires Dec. 31, 2001
State Licenses
Round Butte No. 217
Issued Mar. 10, 1961, expires Dec. 31, 2010
Pelton and Reregulating No. 222
Issued Jan. 9, 1962, Expires Dec. 31, 2011

T.W. Sullivan, located on the Willamette River at Willamette Falls in Oregon City, has a 16 MW capacity. The project operates under a single FERC license, but required no Oregon state license because it was built before the state had a licensing program and was exempted from subsequent regulations. We plan to involve state agencies when we reapply for our FERC license in the 1998-99 planning period. Our reapplication will include both the T.W. Sullivan and Bull Run projects.

T.W. Sullivan
FERC License No. 2233
Issued May 23, 1980, expires Dec. 31, 2004
State Licenses: None

Bull Run involves the Sandy, Little Sandy and Bull Run Rivers in Clackamas County, and has a 22 MW capacity. The project is covered by a single FERC license and, like the T.W. Sullivan project, was built before Oregon established licensing requirements and is exempt from the state's licensing requirements. We plan to reapply for our FERC license in the 1998-99 planning period, and our reapplication will include both the T.W. Sullivan and Bull Run projects.

Bull Run
FERC License No. 477
Issued May 23, 1980, expires Nov. 16, 2004
State Licenses
None

North Fork is comprised of three facilities on the Clackamas River: North Fork (54 MW), Faraday (44 MW) and River Mill (23 MW). All three facilities are covered by a single FERC license, and two Oregon state licenses. We plan to reapply for our FERC and State licenses within the 1998-99 planning period, and our reapplication will include the three North Fork facilities along with the Oak Grove project (see below).

North Fork
FERC License No. 2195
Issued Sept. 1, 1955, expires Dec. 31, 2006
State Licenses: North Fork 202, Faraday 203
Issued Sept. 13, 1956, expires Dec. 31, 2005

Oak Grove is a project on the Oak Grove Fork of the Clackamas River with a 44 MW capacity. It is covered by a single FERC license. The Timothy Lake portion of the Oak Grove project is covered by an Oregon state license. We plan to reapply for our FERC and state licenses within the 1998-99 planning period, and our reapplication will include the Oak Grove project and the three North Fork facilities.

Oak Grove
FERC License No. 135
Issued Apr. 9, 1990, expires Aug. 31, 2006
State Licenses: Timothy Lake facility
Issued Sept. 19, 1953, expires Dec. 31, 2002

Renewable Resources

Action items from 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Work with the OPUC to address recovery of costs for renewable resources in excess of avoided costs to ensure costs are not stranded.*

We participated in the Comprehensive Review and support the SBC identified there for funding the development of renewable resources.

- *Identify other sources of funding renewable resources, including marketing to customers.*

We support an SBC to fund future new renewable resource development, and are working with interested parties to develop a proposal.

- *Continue participation in the Northwest Regional Solar Monitoring Network.*

The Northwest Regional Solar Monitoring Network, sponsored by the University of Oregon, maintains a database of sites in the region that have the potential to be developed for solar generation. We continue to participate in the Network.

- *Continue participation in the OSU Wind Research Cooperative.*

We continue to participate as an active member in Oregon State University's Wind Research Cooperative.

- *Improve our capability to meet energy needs of our customers, including pilots and research.*

Our experimental tariff, Schedule 54, allows customers to purchase power generated from renewable resources.

- *Monitor advanced or emerging technologies, such as fuel cells and distributed renewable resources.*

We conducted a fuel cells market and assessment study with Battelle Pacific Northwest Laboratories which was completed in February 1997. While fuel cells are still too expensive to be a viable resource, we intend to look for opportunities to demonstrate the technology.

- *Evaluate renewable energy or advanced technology demonstration projects for potential pilots.*

We have been evaluating an innovative AC photovoltaic panel, the Solarex AC Powerwall, which can be connected directly into the customer's breaker panel for utility interconnection. We have completed the planning phase and have selected four sites. One installation is completed, and the others are awaiting structural evaluation for an innovative mounting system. The manufacturer will monitor each two-panel installation *via* a modem link.

- *Continue to work toward completion of the Columbia Hills and Vansycle Ridge wind resource projects. If we conclude that either project is not technically or economically feasible, explore alternative renewable resource opportunities, including geothermal and firm renewable resource purchases, that would provide long-term environmental and resource diversity benefits. (As of the date of this updated plan [September 30, 1995], the Columbia Hills project has been terminated due to the wind developer not being able to comply with contract terms.)*

Vansycle Ridge Wind Resource Project. Acting on a commitment in our 1992 Plan and working with the OPUC, we issued a Request for Proposals (RFP) for cost-effective renewable resources in June 1993. We short-listed five proposals for contract negotiations, including the one for Vansycle Ridge. In May 1995 we completed negotiations with Kenetech, the project developer, and signed a Memo of Understanding. Our 1995-97 Plan Technical Report (page 8-19) describes a power sales contract with Kenetech for 25 MW, or 7.5 MWa.

These agreements have twice been reassigned. On May 29, 1996, Kenetech filed for bankruptcy under Chapter 11, and sought to sell its rights to develop the Vansycle Ridge project, along with its power purchase agreement, to another developer. Kenetech then began negotiating necessary contract amendments with us to respond to previous Kenetech defaults and missed milestones in the project development schedule so they could render the contract assignable to another developer. To honor our commitment to develop responsible renewable resources, we negotiated revised terms with Kenetech that made their contract commercially assignable. More importantly, we agreed not to reduce the price term, thus protecting project revenues.

In October 1996, two developers—Zond and Energy Unlimited—appeared before the bankruptcy court seeking permission to acquire the asset. The court scheduled an auction, and the following month, Zond outbid Energy Unlimited. We executed a new contract with Kenetech, consenting to Kenetech assigning the project to Zond.

The project soon changed hands again. In January 1997, Enron purchased Zond. Because Enron was in the process of merging with PGE, we saw a potential conflict of interest regarding the Vansycle Wind project. We consented to Zond selling its rights to develop the project to ESI Energy, an affiliate of Florida Power and Light. This project is now moving ahead as a 7.5 MWa facility. ESI informs us that they intend to have all permits in place by February 1998 and begin commercial operation in January 1999.

Columbia Hills Wind Resource Project. Our 1995-97 Plan reported that we had terminated the Columbia Hills project because the developer, Kenetech, had not been able to comply with its contract terms. Kenetech filed for bankruptcy on May 29, 1996.

Demand-Side Actions

Key Performance Objectives

Action items from 1995-97 Plan are shown below in italicized type, and are followed by our update. For additional details about our ongoing energy-efficiency accomplishments, refer to the following documents:

- "1996 Annual Review of 1995 Energy Efficiency Programs," submitted to the OPUC on April 1, 1996.
- "1997 Annual Review of 1996 Energy Efficiency Programs," submitted to the OPUC on April 3, 1997.

1. Acquire the following target goals during the Action Period: 20 MWa in 1995, 8.1 in 1996 and 7.35 in 1997. This goal is based on the following three principles:

- *Acquire savings below short-run marginal costs at a sustainable pace.*
- *Aggressively pursue economic lost opportunities based on long-run marginal costs.*
- *Maintain market presence and capability for possible future increases in DSM when justified.*

	1995	1996	1997
1995-97 IRP Target (MWa)	20	8.1	7.35
Achieved Savings (MWa)	20.12	10.38	7.35*
% of Target	101	128	100
*1997 savings is the goal shown in the 1995-97 Plan.			

We exceeded the target goals listed in the 1995-97 Plan, as shown in the accompanying table. Details of our savings acquisitions, costs and pacing are included both in the Energy Efficiency Annual Reviews described above, and in the following pages. We have, and continue to, maintain our presence in the energy-efficiency marketplace, and position ourselves for possible future increases in our efforts when the market justifies it.

2. Pursue lost opportunities in new construction. Increase composite market penetration rates over the Action Plan period (this will require establishing 1995 baseline). Emphasize R&D and pilots in this area to encourage more efficient design and construction practices.

Commercial Earth Smart Savings (MWa)	1994	1995	1996
	2.84	1.09	2.49

We have been very successful in capturing energy efficiency savings in new construction, as evidenced by savings acquired in commercial and industrial new construction for 1994 through 1996, as shown in the accompanying table.

To encourage more efficient design and construction practices in the commercial market we are focusing on our Commercial Earth Smart program, which began operating January 1, 1996. As mentioned below under Demand-Side Actions, we currently have 14 active building projects in the program, compared to a target of six projects.

The Commercial Earth Smart program pushes customers to go beyond efficiency levels required by code. To assist our customers we provide customized services and assistance, including architectural design, mechanical design and environmental consultation. Under Earth Smart we intervene as early as possible in the design and construction process, to maximize our influence in attaining comprehensive packages of high-efficiency measures. The program also requires building commissioning, to help ensure that intended efficiency measures are in place.

Early results of the program have won the confidence of developers and governmental agencies. For example, a customer who had previously had difficulty obtaining approval for the energy design of their new, six-building project obtained county permit approval by agreeing to participate in, and qualify for, our Earth Smart program. We had been working with this customer from the beginning to implement more efficient designs into their plans.

We have established a baseline from which to measure penetration rates in the new, non-residential market for 1994-95. We completed this baseline report in July 1996. While we have not established a similar baseline for the residential market, we continue to work with our Evaluation Steering Committee to come to a consensus on a method for estimating energy-efficiency program penetration rates. For many measures, definitive penetration studies would be prohibitively expensive for us to pursue individually. Because some portion of energy-efficiency acquisitions may be approached on a regional basis in the near future, we have taken a leadership role in working with NEEA to sponsor regional programs.

In the new residential market we have used the Multifamily and Single-Family Long-Term Super Good Cents (LTSGC) programs, and the Manufactured Home Acquisition Program. Almost 75 percent of our energy efficiency savings in this segment came from the Multifamily LTSGC program.

3. Increase customer satisfaction with our energy efficiency services performance. Design a market research instrument to *measure and track awareness perceived value and satisfaction, and to measure the effectiveness of our services. Evaluate the results with the involvement of our work groups.*

Our 1995 and 1996 Customer Satisfaction Studies are part of a series of broadly based studies that track our residential customers. We perform our studies semiannually to reveal evolving trends of public opinion and customer perceptions of utility operations and services. We measure overall customer satisfaction by looking at 19 service factors, one of which is Energy Efficiency Programs and Special Offers. For the past two years our customers have rated this category of service as Satisfactory, within the context of performance for the other 18 factors.

4. Explore means of improving asset utilization to enhance price competitiveness and business value. This effort has value in both a regulated and competitive environment. Examples are geographically targeted DSM for T&D benefits and some forms of load management.

PGE explored space and water heat load control service in conjunction with TOU rates in four separate marketing approaches under Schedule 330. In Salem, PGE targeted a geographic area that was scheduled for a transmission upgrade. Customer acceptance was too low to allow us to defer the upgrade. Two other issues may have reduced market acceptance. First, the perceived bill savings of $30 to $80 a year may be insufficient to overcome the decision to install the required control equipment. Second, explaining TOU rates and energy control at the same time may have made the offer difficult to understand. Customers must understand TOU rates before we offer them a fee-based energy control service.

5. Manage the risk of stranded regulatory assets in several ways, including by minimizing discretionary program cross-subsidies and requesting expense treatment for DSM costs from the OPUC.

In 1995, we introduced legislation to lower the carrying cost of past energy-efficiency investments. This was passed as A-Engrossed Senate Bill 1036, which gave the OPUC authority to approve energy-efficiency investments as bondable conservation investments. In October 1996, we completed our refinancing of energy-efficiency investments made through the end of 1995. We passed on savings of approximately $21 million (NPV) to our customers effective October 11, 1996. We also reduced our stranded asset risk for customers by shortening the amortization period to five years for energy-efficiency activities occurring as of January 1, 1996.

6. Maintain market capability and presence to enable acquisition scale-up when or if needed in the future. Consider proposals for reducing program costs and market transformation activities.

We regularly review all energy-efficiency programs. We took a number of cost-saving actions during 1995 and 1996, including the removal of many measures that no longer were cost-effective.

We also introduced new initiatives that focused on market transformations, lost opportunities and the development of more flexible, customized consumer programs. These activities are better suited to the current market conditions of increasing competition, customer choice and regulatory restructuring than the prescriptive programs that characterized much of our earlier energy-efficiency work. Two of our 1996 initiatives, market transformation and our increasingly early intervention in the design and construction process for new construction, are financially front-loaded. Current costs may not result in savings for several years. This is a major shift from our earlier focus on equipment rebates in which program expenditures within a given calendar year were a reasonable proxy for savings achieved in that same year.

In 1997 we are shifting some of our market transformation support to regional activities sponsored by NEEA, in which we have taken a leadership role.

7. Pursue ways to accomplish Oregon['s] goals for energy efficiency by means other than utility subsidy programs through participation in the Regional [Comprehensive] Review, *PacifiCorp's Conservation in a Competitive Environment Group and other forums.*

We are actively participating in regional energy-efficiency forums. For example, Al Alexanderson, PGE's Vice President and General Council, served as a member of NWPPC's Comprehensive Review process. PGE was among the parties that signed the final review document.

Residential—Existing Housing

Action items from 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Scale down the weatherization program to a maintenance level and continue to satisfy statutory requirements.*

In 1996 we changed our weatherization tariff to increase the cost-effectiveness of our residential weatherization programs by reducing them to a maintenance level while continuing to support our trade allies and satisfy customer expectations. We eliminated window and door measures, which were not cost effective, and reduced rebates to the minimum levels outlined in state statutes.

- *Maintain the efficient water heater program aimed at the replacement market, to serve as a bridge until the new federal efficiency standards take effect.*

Our efficient water heater program remained cost-effective in 1996, even with lower cost-effectiveness limits. We plan to continue our program as a transition to the 1998 federal appliance codes.

- *Participate in the regional compact fluorescent lighting (CFL) market transformation initiative at the level currently contracted for, allowing for adjustments and expansion consistent with collaborative market transformation efforts.*

In 1996, we replaced our consumer rebate program with LightSaver, a regional compact fluorescent lamp (CFL) market transformation program under which we shifted rebates from consumers to manufacturers. In February 1997, the OPUC accepted our request to approve the LightWise program as a market transformation offer. Also in 1997, we transferred sponsorship of the LightSaver program to NEEA, who renamed it LightWise. The basic program concept remained unchanged.

- *Maintain a presence in the retail channel by focusing on do-it-yourself customers through leverage with trade allies, especially retail home improvement stores.*

In 1997 we promoted do-it-yourself, energy-efficient products through more than 80 retail home improvement centers. Promotions included in-store, product specific, point-of-purchase signs urging customers to choose energy-efficient products such as CFLs, water heating and insulation. We also assisted in developing a training video for one retail chain.

Residential—New Construction

Action items from 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Continue our multi-family program aimed at capturing shell and non-shell measures.*

We discontinued offering rebates for "shell" measures that enhance the energy efficiency of the exterior walls, doors and windows in August 1996 as recommended by the OPUC in their review of our "1996 Annual Review of 1995 Energy Efficiency Programs." Measures for energy-efficient equipment continue to be cost-effective, and we continue to offer them to builders.

- *Terminate the current single-family Long-Term Super Good Cents program. The volume is too low and shell measures are too expensive.*

We discontinued offering shell measure rebates in both our single- and multi-family LTSGC programs, as reported in our answer to the preceding question.

- *Explore creative alternative program designs that focus on measures like advanced framing (shell), air/duct sealing,* *lighting and appliance packages. Focus on measures of higher value to the builder and home buyer.*

We now serve our residential, new construction market through the Residential Earth Smart program, a broader effort that emphasizes customer choice. Earth Smart continues to promote energy-efficient design and construction practices, and builders must select options from each of three categories: healthier buildings, environmental, and energy and resource efficiency.

Commercial and Industrial Programs (Overall)

Action items from the 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Identify and assist customers in selected energy efficiency demonstration projects that either show significant promise for broad applicability for potential impact, or visibly showcase efficiency to raise awareness.*

We worked with one high-technology manufacturer to demonstrate a new technology, ultrasonic humidification. To date, two other PGE customers have visited the site and are considering this technology. We also have promoted and supported new technologies through workshops and analysis. We are focusing on working at the design stage with developers of large-scale, multi-use projects, such as the transit-oriented developments along the West Side Light Rail corridor.

- *Use the rebate delivery mechanism, design assistance mechanism, tailored incentives and participation in multi-party transformation efforts to introduce a new technology and practices and increase their use. Maintain our technical support and engineering capability to support these efforts. We will need to continue to position ourselves as a source of energy and technology expertise.*

We are using all of the methods described above, including participation in NEEA, and our Commercial Earth Smart program, to encourage appropriate technologies and practices, and to deliver technical and engineering support.

- *Maintain visibility of benefits from efficiency by actively promoting—through educational efforts, seminars, advertising and training—customer awareness of efficiency opportunities in business operations.*

We reinforced the benefits of efficiency by conducting seminars and training sessions, providing advertising and technical articles, providing technical and educational information, and supporting technical professional organizations and alliances. These activities occurred in such subjects as daylighting, lighting controls, new developments in lighting sources such as compact fluorescent and high-intensity discharge (HID) fixtures and lamps, egress lighting requirements, motors and motor controls, industrial air compressor systems, Commercial Earth Smart and sustainable design of new buildings, building commissioning, industrial and outdoor lighting; recycling of lamps and ballasts, efficient applications of electric water heating; evaporative cooing in lieu of direct expansion (DX) cooling for some applications, infrared heating applications in manufacturing, and industrial process energy efficiency improvements. We also sought opportunities through events and conferences sponsored by the Northwest Industrial Energy Forums and Association of Professional Energy Managers.

Our specialists also provided technical assistance both to our customers and to our hot-line personnel and account representatives. Technical assistance included efficient applications for lighting, industrial processes, food service, HVAC, and new commercial and industrial construction.

Commercial—Existing

Action items from 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Focus on the replacement and renovation market. Restructure program activities to concentrate on capturing savings at these windows of opportunity. Develop and track penetration rate* *measures. Establish penetration baseline and set improvement goal within six months of the OPUC's acknowledgment of this IRP. . . .*

We focused on the replacement and renovation market. In 1995 we acquired 9.04 MWa, which was 93 percent of our target. In 1996 we saved 4.91 MWa, or 169 percent of our target. Our work in establishing market penetration baselines is discussed earlier in this Update section under Key Performance Objectives.

- *Explore the viability of providing "commissioning" services for existing buildings.*

We explored commissioning services for existing buildings by participating as one of the primary sponsors of the Northwest Conference on Building Commissioning held in Portland on Nov. 4, 1996, and cosponsored this important event in previous years.

- *Support regional and national efforts to influence and reinforce more energy-efficient office equipment.*

We support the Environmental Protection Agency's (EPA) Energy Star program, but based on our own extensive research believe that such measures are not highly cost-effective. While we encourage our customers to select energy-efficient office equipment, we are not investing in promotions for such measures.

- *Explore and develop different financing approaches for energy efficient projects, including third party financing. Reduce rebates for most retrofit situations.*

While we have not explored third-party financing as a way to encourage energy-efficient projects, we have reduced rebates. Late in 1995 we made program changes, effective January 1, 1996, to make our programs consistent with our 1996 energy-efficiency objectives. Changes to Schedule 232 included lighting rebates restructured to encourage more aggressive pursuit of energy efficiency, chiller rebates calculated a new way to reflect a lower incremental cost of new units and limited rebates to no more than 30 percent of the incremental cost of a high-efficiency unit, rooftop economizers eliminated because the measure was not cost-effective, and site-based incentives revised for more flexibility in delivering energy-efficient solutions to different markets.

Commercial—New

Action items from 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Continue active program efforts to capture otherwise lost opportunities. Develop and track penetration rate measures. Establish penetration baseline and set improvement goal within six months of the OPUC's acknowledgment of this IRP. . . .*

Our efforts continue in the new commercial market. Our work in establishing market penetration baselines is discussed earlier in this update section under Key Performance Objectives.

- *Pursue integrated design demonstration projects to encourage more efficient design practices and adoption of new technologies. Set a goal of having at least six projects in process by the end of the Action Plan period.*

We currently have 14 active building projects in our Commercial Earth Smart program. We have another three projects on hold due to the effects of Measure 47 or bond elections, and another seven projects are signed, or close to signing, and due to begin soon.

- *Collaborate with other regional parties to encourage building commissioning practices. Explore ways of eventually incorporating this service into program activities.*

We were one of the primary sponsors of the Northwest Conference on Building Commissioning, held in Portland on Nov. 4, 1996, and cosponsored this important event in previous years. We have incorporated building commissioning into our Commercial Earth Smart program, and reinforce the measure with financial incentives.

- *Continue to attempt to intercept projects further upstream in the building design process.*

We have built efficient design into our current efforts. To qualify for our Commercial Earth Smart program, a customer must participate at the building design level.

- *Support ODOE and N[W]PPC leadership in reinforcing local government enforcement of the new building code.*

We financed implementation of the 1996 building code with joint funding from other utilities to support the revision of software, training and training materials necessary for ODOE to support enforcement of these important new energy-efficiency standards.

Industrial—Process

Action items from the 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Continue to pursue industrial process improvements through support for (1) efficiency design, (2) verifying results and (3) analysis and financial assistance that encourages customers to stretch designs to incorporate new efficiency concepts. Limit rebates to new technologies. Collaborate with other state and regional parties.*

In our continued efforts to influence the energy-efficiency of industrial process design, we have found that many of the manufacturing design decisions are made out of state, and often out of country. Further, investments made to assist with the design may take several years to produce energy savings. Our programs are customized—we determine on a building-by-building basis which processes or technologies to improve through incentives. We plan to continue working with NEEA on any industrial process programs they may develop.

- *Identify the potential of specific projects that materialize and report on our adoption rate, including both in-process and eventual completion figures. With the announced high-technology expansions over the next few years, we anticipate a high efficiency potential, but our customers' adoption rate is uncertain.*

Since 1995, we have participated in the design or construction of every new high-technology facility sited within our service territory. When the customer has declined any type of project review or assistance with energy efficiency, it usually was because the customer had too little time, or was working within a fixed-price design and construction bid.

- *Continue to use contract provisions to help minimize the risk of stranded asset risk recovery.*

Beginning in the fall of 1993, our contracts with new industrial process customers require the customer to pay back energy-efficiency project costs on a prorated basis should they leave our system before a specified date.

- *Support regional and national level efficiency initiatives to address the Original Equipment Manufacturer (OEM) market, such as motors and air compressor systems.*

We support energy-efficiency programs for OEMs through our participation with NEEA. Before the Alliance was formed we supported a regional motors program both through funding and participation.

- *Partner with other regional parties to help influence key local design and construction firms toward more energy-efficient practices.*

While we are not aware of other regional parties that are striving to influence local design and construction firms, we have conducted "brown bag" presentations with local firms to discuss energy-efficient practices. We have participated with the NWPPC in training seminars presented by SuperSymmetry Services to educate and introduce new energy-efficient technologies to the microelectronics industry. We continue to encourage our customers in this industry to evaluate and incorporate the technologies presented at these seminars into their facilities.

- *Monitor progress on energy efficiency target goals recognizing that customers control energy efficiency projects. We will meet with the ODOE and others to provide updated information on* *progress and work together to influence more companies to adopt energy efficiency measures into their processes.*

We hold update meetings with ODOE and NWPPC, among others. We also have met with and supported NWPPC staff to discuss ways to increase penetration of energy-efficient practices into manufacturing processes.

Load Management

Action items from the 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Continue to conduct load research.*

We conduct load research on an ongoing basis. Our findings are proprietary, but would be reflected in any revision to this Plan that we might propose based on our monitoring of the appropriate signposts.

- *Continue to test home energy management on a T&D targeted basis.*

We explored space and water heat load control service in conjunction with TOU rates in four separate marketing approaches under Schedule 330, as discussed above under Key Performance Objectives.

- *Continue to experiment with time-of-use and market-based pricing options.*

During the 1995-97 planning period we offered market-based pricing through Schedules 87 and 67. First, we offered Schedule 87 to industrial, commercial and general service customers with loads greater than 10,000 kW. Subsequently, we offered Schedule 67 to customers with loads greater than 5,000 kW. Customers with loads greater than 1,000 kW could also find more flexible pricing through Schedule 85.

- *Promote off-peak and nonfirm retail end-use applications.*

We provided optional curtailment service to industrial, commercial and general service customers through Schedule 88. We also pursued pilot programs to promote off-peak service for residential customers through time-of-day service options through Schedule 7, and the home automation services included in Schedule 330.

Fuel Substitution

Action items from the 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Market "least cost" electric solutions that substitute for higher-cost fuels on a societal resource cost-effectiveness basis. One example currently identified in this [1995-97] IRP is zonal heat in residential single-family new construction.*

We have no plans to request the designation of zonal heat as a residential energy efficiency program.

- *Promote electro-technologies that recognize environmental, fuel efficiency and productivity benefits.*

We explored with certain customers a variety of electro-technologies: electric lawn mowers; electric commercial cooking options including induction cooking, new efficient fryers and oil-less fryers, combination ovens, and conveyor ovens; electric lift trucks; electric vehicles; ozonation of waste water; electric heat treating; infrared and ultraviolet curing of paint; ultraviolet treatment of wastewater; ozone treatment of HVAC and industrial cooling tower water; adjustable speed drives; and electric noise cancellation. In some cases these electro-technologies offered savings in overall energy usage while improving productivity and lowering environmental impacts.

Evaluation

Action items from the 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Emphasize providing timely management information response time and process evaluations, including tracking of market penetration. De-emphasize impact evaluations consistent with planned program changes.*

We have established a baseline from which to measure penetration rates in the new, non-residential markets, as discussed above under Key Performance Objectives. We also have worked through the Evaluation and Verification Steering Committee to successfully identify the methods to use for evaluating market penetration. We plan to begin implementing these new methods by the end of 1997.

	% of Program Savings 1996 Evaluation Plan	
	Planned	Completed
1992	100	100
1993	99	92
1994	43	37
1995	17	16

- *Implement the evaluation plan filed with the OPUC.*

We implemented our 1996 Evaluation Plan as described in the accompanying table.

- *Determine market penetration baselines and measure on an ongoing basis. Specifically for existing and new commercial programs, initially develop and track program penetration rates relative to our customer base. Document actual annual penetration rates by program for 1991-95 within six months of OPUC acknowledgment of this IRP.*

Our work in establishing market penetration baselines is discussed earlier in this update section, under Key Performance Objectives.

- *Incorporate project performance and verification into customer evaluation plans to eliminate the need to revisit customer sites.*

We included a verification plan in agreements with customers participating in our Industrial Process program. We also increased pre- and post-implementation monitoring for projects completed under that program. Through these efforts we have reduced the necessity of revisiting customer sites.

Market Transformation

Action items from the 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Support market transformation activities and work with regional collaboratives to improve retail channels for efficient products and practices. The initial areas of focus include appliances (refrigerators, horizontal-axis washers, lighting fixtures) and integrated building design standards.*

Before NEEA was formed we participated in a number of regional energy-efficiency programs, including those for CFLs and fixtures, motors, building commissioning and manufactured housing.

Today we support market transformation efforts through our participation in NEEA. We also have: participated in the American Institute of Architects Architecture + Energy (A+E) awards; promoted building commissioning and daylighting analysis; sponsored The Natural Step regarding the Swedish systems approach to sustainability; sponsored the NW Regional Council of the President's Council on Sustainable Development; and participated in the latter's subcommittee on sustainable development.

- *Support educational and training efforts to increase knowledge of the technology applications and codes.*

As discussed earlier, we helped finance the software and documentation necessary to enforce Oregon's new building codes. We also established a performance-based fee type project for a local high school with the Rocky Mountain Institute, participated in the A+E awards, and conducted other educational activities as described above under Commercial and Industrial Programs (Overall).

- *Use financial or promotional delivery mechanisms to introduce selected technologies or practices to the market.*

Through our Commercial Earth Smart program we encourage our customers to design energy efficiency into their buildings and processes.

- *Participate in the regional effort to promote the use of CFLs in residential applications.*

Our work with CFLs is discussed earlier in this Update section under Residential—Existing Housing.

- *Use Earth Smart marketing to encourage the use of energy-efficiency technology in the renovation and new construction markets, leveraging accompanying environmental packages.*

To participate in our Earth Smart program, customers must become involved at the design phase where energy-efficient technologies and environmental packages can be built in.

- *Encourage integrated design for new commercial buildings.*

We encourage integrated design in new commercial buildings through our Commercial Earth Smart program.

- *Encourage building commissioning to help transform industry practices.*

We support building commissioning, as discussed earlier in this Update section, both by participating in local conferences and through our Earth Smart program.

Transmission and Distribution Actions

We continue to maintain and upgrade our transmission system as needed to ensure safe and reliable operation, while deferring costs and activities that are not yet prudent or economical. While we have sought out more efficient alternatives to traditional methods for adding capacity, we have found few that meet our needs for timeliness and cost-effectiveness.

Action items from the 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *Implement cost-effective improvements to transmission and distribution facilities.*
    - *Install 45 MVAR per year in distribution substations for voltage and loss support.*
    - *Install 20 MVAR per year in distribution for voltage and loss support.*
    - *Install 385 MVAR of capacitors on the transmission system over a 10-year period to cover reactive losses in the bulk power transformers and transmission lines.*
    - *Upgrade conductors to reduce losses when reconductoring for road widening, customer work, etc.*

We were one of the charter utilities to participate in the EPA's Energy Star program for distribution transformers. Also, we put our reactive support program on hold pending the outcome of BPA's proposed penalty for poor power factor performance, as measured by VAR consumption. Now that BPA has announced their penalty structure, we are reviewing our reactive support program and will have a revised plan developed during 1998.

We routinely upgrade conductors for loss reduction when other work is being done, and will continue this practice.

- *Implement Beaver plant transmission line, if cost-effective.*

  The Beaver transmission line would have been more cost effective than a conventional, point-to-point, wheeling contract. However, we have not implemented the transmission line project because it is not yet cost-effective under the terms of the current BPA Integration of Resources contract.

- *Implement integrated planning to ensure coordination of distribution planning and resource planning for distributed resources and DSM.*

  We routinely review capacity additions to look for better alternatives, but to date none have proven sufficiently cost-effective or timely.

- *Investigate feasibility of deferral of transmission capacity additions.*

  We have reviewed several locations for possible deferral with distributed generation or energy-efficiency measures. Distributed generation has proven to be too expensive, and energy efficiency measures have not been effective in acquiring the required load reduction.

- *Continue to evaluate distributed generation opportunities, especially in areas where customer loads grow faster than general service area forecast.*

  We are developing a prototype for a capstone turbogenerator at the Beaver plant and are currently looking for commercial and residential opportunities for installing this technology to help increase our knowledge in this area. Also, see our response to the preceding action item.

- *Monitor technology changes, looking for breakthroughs that could alter the economics or performance characteristics of distributed resources.*

We continue to look at technological alternatives, and are conducting a pilot program for an automated reconfiguration system in the Colton-Molalla area to speed restoration of service. To date, we have not found technological breakthroughs that would reduce the cost of conventional capacity additions.

Regulatory Actions

We continue to monitor our signposts, and work with the OPUC to take any regulatory actions necessary to help ensure an efficient, responsive planning process. Action items from the 1995-97 Plan are shown below in italicized type, and are followed by our update.

- *We propose a periodic review of signposts and energy conditions for all resources to reduce the time from when we recognize a signpost, identify a need for action and take action. The review format would be an open dialogue with the IRP public participants. The process would enable planning stakeholders to assess specifics around signposts and be involved in an ongoing review of signposts and energy conditions.*

We reviewed the signposts identified in the 1995-97 Plan as we prepared for our merger with Enron, in preparation for our Customer Choice Initiative, and in the process of preparing this Plan. We will continue to review our business environment as issues arise.

1. *We propose that we communicate any DSM action adjustments in the annual energy efficiency report. Because this report and its DSM actions are reviewed annually by the OPUC, this may be the best means for communicating with you on proposed adjustments to our DSM actions, if any. This was done for the 1995 DSM pending the completion of the current Plan.*

We continue to communicate adjustments in our energy-efficiency action through the annual energy efficiency report. However, because the best means for communicating such adjustments may change with open access, we plan to review this process from time to time.

- *If signposts indicate a significant change in actions is necessary, we would provide the OPUC with an IRP update . . .*

We are implementing this item with the current Plan.

- *The Commission's Order stated that PGE's customers should have the opportunity to participate in the next IRP process. We will notify customers early in our next process, and invite them to participate and provide input.*

We have updated our mailing list, and sent notice to approximately 170 individuals.

- *As of the fall of 1996, the Commission has scheduled an informal review of least-cost planning in Oregon. Should this review result in any changes, we will adjust the scope and timing of our next Plan or Plan updates accordingly.*

The OPUC opened a formal review under UM 828 in the fall of 1996, but closed the docket in 1997 pending the outcome of the state legislative session. UM 828 is not active at this writing.

Signposts

In our 1995-97 Plan we identified signposts during that action period that would be most likely to "cause us to reconsider planned or preparatory actions," as identified through our modeling and sensitivity analysis. Rather than repeat a discussion of signposts here, please refer to our evaluation of signposts in the Planning Approach section above.

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MEMORANDUM

TO: Internal LCP Distribution

FROM: Kathy Phillips-Israel KSPI

SUBJECT: 1998-1999 Integrated Resource Plan

DATE: September 2, 1997

Our 1998-1999 Integrated Resource Plan was filed today with the OPUC. This begins the Commission's formal review process. The Commission is expected to make a decision regarding acknowledgment of our Plan no later than December.

I want to thank everyone that helped with the Plan. The process was on a very tight time schedule, and I appreciate the commitment shown by PGE employees.

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1997 LCP Distribution List

Frank Afranji 3WTC0504	Linda Ecker 1WTC0506	Marlene Huntsinger 3WTC0305	Carole Morse 1WTC0901
Al Alexanderson 1WTC1715	Steve Elliott 1WTC0403	Bob James 3WTC0406	Bill Nicholson 3WTC0403
Gary Barbour 1WTC0901	John Esler 1WTC0901	Julie Keil 3WTCBRHL	Mike Niman 1WTC0504
Lee Barney 1WTC0809	Joe Feltz 1WTC0505	Paul Koehler 3WTC0305	Ham Nguyen 1WTC0504
Dennis Bleything outside	Peggy Fowler 1WTC1713	Doug Kuns 1WTC0702	Sharon Noell 1WTC0702
Carol Brown 1WTC0704	Tony Gin 1WTC0501	Susan Myers 1WTC-BR08	Mark Pfrommer 3WTC0305
Sara Cardwell 1WTC0702	Kirk Gresham 1WTC0503	Mark Litterman 3WTC0403	Jim Piro 1WTC0506
Randy Dahlgren 1WTC0702	Gary Hackett 3WTCBR04	Kelley Marold 1WTC0702	Michael Schilmoeller 1WTC0504
Rich Davis 3WTC0305	Mary Hain 1WTC1301	John McLain 1WTC0704	Ron Sumida 1WTC0504
Dennis Desmarais 1WTC0503	Barbara Halle 1WTC1301	Denise McPhail 1WTC-BR09	Mike Swerzbin 3WTC0305
Dick Dyer 1WTC1702	Steve Hawke 3WTC0406	Mike Mikolaitis 3WTCBR03	Theresa Taaffe 1WTC0704
Jay Dudley 1WTC1301	Greg Hazelton 1WTC0501	Fred Miller 1WTC1710	Michele Farrell 1WTC0702
Doug Boleyn 1WTC0704	Rochelle Lessner 1WTC-BR08	Tom Mathews CPI	Randy Oliver 1WTC0901

Chris Ryder CSS	Enron Paul Wielgus 1WTCBR	Enron Beau Fournet 1WTCBR	Enron Bob Schorr 1WTC-BR 10
Joe Hirko 1WTC1705	Ken Harrison 1WTC1706		

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TWO-YEAR ACTION PLAN

Two-Year Action Plan

In this Plan we recognize two types of energy-efficiency action items: traditional integrated resource planning targets, and transitional actions. The latter are intended as a bridge to the time when a regional SBC will be implemented to fund energy-efficiency activities. We assumed that the SBC, when implemented, would result in higher spending for energy efficiency than we would spend under our traditional planning process. Bridge actions go beyond traditional planning requirements and are intended to maintain continuity in our energy-efficiency capability.

Acquire Energy Savings

The energy efficiency savings targets and budgets shown in the accompanying tables summarize our goals for the 1998-99 planning period. Our energy savings targets reflect the fact that cost-effective energy is more difficult to acquire through the installation of efficiency measures than in the previous planning period. New building codes now set a higher standard for energy efficiency than ever before. At the same time, low prices for the natural gas used to fuel CTs have driven down the cost of electricity, making some efficiency measures less cost-effective than they once were. The result is our conclusion that it is both prudent and realistic for us to strive toward a goal of acquiring 5.91 MWa in energy efficiency savings during 1998, and 6.18 MWa in 1999. Our budget for those years is $12.1 million and $12.3 million, respectively.

EE Targets	MWa	
	1998	1999
Residential	0.42	0.42
Comm. & Ind.	5.2	5.40
Mkt. Trans.	0.29	0.36
Total	5.91	6.18

EE Budget	$ million	
	1998	1999
EE	9.5	9.7
Mkt. Transf.	2.6	2.6
Total	12.1	12.3

Residential

In our 1995-97 Plan we reported that windows and doors no longer were cost-effective. With OPUC approval we removed these measures from our residential program in 1996. Therefore, we expect to acquire less energy through residential

Residential	MWa		
	1997	1998	1999
Weatherization	0.31	0.14	0.14
Low Income Weatherization	0.04	0.05	0.05
New Construction	0.10	0.05	0.05
Lighting	0.10	0.00	0.00
Water Heating	0.20	0.18	0.18
Total	0.75	0.42	0.42

weatherization programs during this planning period.

We have maintained the *status quo* in setting our goals for weatherizing homes in the low-income segment.

We have transferred our lighting efficiency efforts to NEEA, and participate with other members in that context. We've carried forward a continuing commitment to acquiring energy through water heater efficiency programs.

Commercial & Industrial

In the commercial and industrial segment we are willing to look into developing a program for commissioning existing buildings, but we continue to maintain that this is a discretionary resource that we will compare with short-term energy costs.

Commercial & Industrial	MWa		
	1997	1998	1999
Existing	1.9	2.2	2.4
New	1.2	1.2	1.2
Industrial Process	3.5	1.8	1.8
Total	6.6	5.2	5.4

Our target for new commercial and industrial buildings remains unchanged for this planning period. We intend to focus more intently on gaining early entry into the design and development process so that we can maximize the effects of our efforts. At the same time, we are aware that little is planned within the next two years for new industrial process installations in the high-technology segment. Any efforts that we may apply in this segment are likely to produce results after the turn of the century.

Market Transformation

Market Transformation	MWa	
	1998	1999
CFL	.270	.290
Motors	.005	.005
Other	.015	.065
Total	.290	.360

We are actively participating in NEEA and supporting regional programs to help make existing products and practices more energy efficient. We will recognize energy savings gained through these activities as a part of our overall energy efficiency activities within our service territory.

Bridge to a System Benefit Charge

In our present environment we acquire energy savings in the context of a traditional planning process that considers new and existing programs under current market conditions. In our future environment we expect such acquisitions to be funded through an SBC. To build a bridge from the present to the future we will take the following actions.

- Maintain activity levels comparable to those for 1997 by budgeting $12.1 million for existing programs in 1998 and $12.3 million in 1999. This represents a target increase of 1.0 MWa, and a budget increase of $3.4 million over what we originally proposed for the planning period. The energy savings we acquire in 1998 and 1999 may be lower than those for 1997 because of changes both in the building codes and in the marketplace. However, this level of funding demonstrates our undiminished commitment to our existing programs.

Original Targets Proposed at June 18, 1997 Public Meeting		
	MWa	Budget ($ million)
1998	4.91	10.4
1999	5.18	10.6

- Provide up to an additional $1.6 million in unallocated funds in 1998 and $1.4 million in 1999 for additional cost-effective energy savings. We will spend these additional funds only if cost-effective programs can be identified, and if the OPUC has approved them. We will meet quarterly with interested parties beginning in the autumn of 1997 to discuss options, innovations, and alternative forms of program delivery for capturing additional cost-effective savings. At these meetings we also will discuss re-evaluating our current indicators of program activity levels.

- Maintain our activity at the 1997 level to preserve energy-efficiency supply markets in our service territory. Without some minimal level of support during the transition to restructuring, these markets could dry up and limit supply in future years. Preserving this market will provide a bridge to the funding of energy efficiency through the proposed SBC.

Develop Renewable Resources

In our 1995-97 Plan we committed to following through on two wind resource projects, Columbia Hills and Vansycle Ridge. Only Vansycle Ridge is active today, and it will be our sole renewable resource project within this Plan. We also will continue to explore alternatives to the Columbia Hills project.

We may negotiate developing renewable resources within the context of the MOU. Any additional commitment to developing renewable resources and incurring the risk of stranded costs related to these projects in the future may depend on our ability to recover costs through an SBC.

Respond to Signposts

We will continue to monitor the signposts discussed in our 1995-97 Plan and, when we believe action is indicated, submit the appropriate documents to the OPUC. Besides the signposts we established in our previous Plan, we will reassess our strategies regarding our energy efficiency and renewable energy goals should either of the following occur.

- Alternate regulatory framework for recovering energy-efficiency and renewable resource development costs, such as an SBC.
- Direct access for our customers beyond our planned Customer Choice pilot demonstrations.

Resource acquisition, such as repowering the Beaver Plant or building Coyote II, will require amendment to this Plan.

THIS PLAN & THE SYSTEM
BENEFIT CHARGE

This Plan and the System Benefit Charge

In the merger MOU we stated that we would file and support an SBC at least at the funding levels of, and allocated for the purposes outlined in, the final report of the Comprehensive Review. We agreed to file our proposed SBC within six months of the completion of the merger, regardless of the status of state legislative action to establish a minimum standard for Oregon.

We support an SBC, and believe we have built a bridge for a smooth transition to that future. To make sure we are aligned with issues we expect to arise during this transitional period, we have increased of our energy-efficiency resource acquisitions by 1 MWa beyond our original proposal. We agreed to maintain our energy-efficiency delivery capability at 1997 levels. We describe our proposed SBC in our Customer Choice Initiative.

September 1, 1997
PORTLAND GENERAL ELECTRIC COMPANY
121 S.W. Salmon Street
Portland, Oregon 97204

Printed on recycled paper

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scenarios – low, medium-low, medium, medium-high, and high. Our recent UE 115 filing contains a detailed 2002 monthly load forecast.

In this Resource Plan, we develop three load scenarios consistent with these two filings. In the base, or medium growth, case, we assume loads to increase at a "moderate" rate from the 2002 base filed in UE 115. For our sensitivity analysis, we use "high" and "low" load growth scenarios. These three cases apply growth rates similar to those developed in previous Integrated Resource Plans, albeit extending for 50 years (rather than 20).

We are also able to model medium-low and medium-high load growth scenarios, as in previous Integrated Resource Plans. However, we have not included them in this Resource Plan, as we feel the high and low forecast scenarios are sufficient for sensitivity analysis.

Load Forecast

Table 4 below displays year 2002 loads and annual load growth assumptions for the medium (base), high, and low load scenarios. Peak forecasts are under "1-in-2" conditions, meaning that 50 percent of the time peak demand could exceed these projections. (See the definition of "1-in-2" loads on page 19.)

Table 4: Load Growth Scenarios

	2002 Energy (MWa)	2002 Peak (MW)	Growth Rates (Annual %)
High Growth Forecast			
Residential	995	2,201	2.53
Small Nonresidential	206	389	3.68
Large Nonresidential	1,396	1,809	3.37
Med. Growth Forecast			
Residential	965	2,134	1.30
Small Nonresidential	200	376	2.27
Large Nonresidential	1,383	1,793	1.81
Low Growth Forecast			
Residential	927	2,050	0.14
Small Nonresidential	192	362	1.27
Large Nonresidential	1,297	1,681	0.87

Figure 1 shows forecasted 2002 peak demand by month by customer group. Most of the variation across months is due to variation in residential peaks. Figure 2 shows forecasted 2002 energy demand by month by customer group. Most of the variation across months is again attributable to variation in residential load. Figure 3 shows long-term energy demand by customer group under high, medium, and low growth forecasts summarized by Table 4.

- F I N A L D R A F T -

Chapter 3
Electric Loads within the City

In this Chapter, we develop estimates of the 1999 total electric load within the City limits using information (based on 1995 data for PacifiCorp and 1996 for PGE) submitted to the City in 1997 by PGE and PacifiCorp during discussions about franchise fees. Then using customer class load forecasts from PGE's UE-102 filing, we estimate annual load within the City by customer class. Determination of monthly electric load shapes is based on PGE's forecast of total monthly electric peak demand and energy by customer class, also from UE-102. While rough, and not based on the forecasting models currently utilized by PGE and PacifiCorp, the resulting estimates provide the City with a close approximation of the size and shape of the electric load within the City limits. More accurate estimates of City load shapes by customer class for 1999 and future years can be readily obtained from PGE and PacifiCorp if the City decides to take pursue additional work on this project.

In early 1997, the City, PGE and PacifiCorp, along with other parties engaged in a series of discussions to develop an alternative to the current franchise fee structure, which is based on a percent of jurisdictional sales of electricity. PGE and PacifiCorp provided the City and its consultants with detailed information on sales of electricity by customer class within the City limits. PGE supplied total megawatt-hour (mWh) sales by customer class for 1996, and PacifiCorp provided data for 1995. This information is summarized and shown in the first two columns of Tables 3-1 (PGE) and 3-2 (PacifiCorp). The third column in Table 3-1 shows PGE's total annual mWh sales by customer class, taken from its 1996 FERC Form 1. The ratio of City loads to total PGE sales by customer class is shown in the fourth column. PGE's projected mWh sales by customer class for 1999, taken from PGE's UE-102 filing, are shown in the fifth column. The final column on Table 3-1 was calculated by first increasing PGE-City sales by 2%, and then applying the customer class percentages from column 5.

The same procedure was used on Table 3-2 for PacifiCorp. We used the PGE customer class percentages because PacifiCorp does not have a recent rate filing before the OPUC, which would have projected loads by customer class for Oregon. In addition, the percentage increase in load from 1996-99 for PGE and 1995-99 for PacifiCorp was based on conversations from 1997 with PGE and PacifiCorp staff. Both companies indicated that most of the Oregon load growth in recent years was occurring outside of City limits, and that City electric load growth would be below 1 % annually for the foreseeable future. Table 3-3 shows the combined total annual sales of 6.66 million mWh within the City limits for PGE and PacifiCorp.

The next step is to estimate monthly load shapes for peak (MW) and energy (mWh) sales within the City limits. Table 3-4 shows this calculation. The first step is to take total PGE monthly mWh sales by customer class from the UE-102 filing. These values are shown in the first four rows of Table 3-4, page 1 of 2. The next step is to convert these monthly values into percentages by month, then by customer class. This calculation is shown on the next four rows of Table 3-4, page 1 of 2.

Monthly mWh sales within City limits by customer class for 1999 were estimated by multiplying total mWh sales with the City (Table 3-3) by the monthly and customer class load percentages. The resulting values are shown in the last four rows of Table 3-4, page 1 of 2. A similar process was used to develop total monthly MW peak loads within City limits by customer class. This is shown on Table 3-4, page 2 of 2.

	Sales to COS Customers	Three Year Average of COS Load
1989	14,901,168	
1990	15,431,553	
1991	15,860,175	
1992	15,643,858	15,645,195
1993	16,557,830	16,020,621
1994	16,829,879	16,343,856
1995	17,067,008	16,818,239
1996	17,509,158	17,135,348
1997	18,254,801	17,610,322
1998	17,443,473	17,735,811

Source: OPUC Utility Factbook 1998

Three Year average to adjust for weather.
Load is increasing prior to Direct Access Transition Charges.

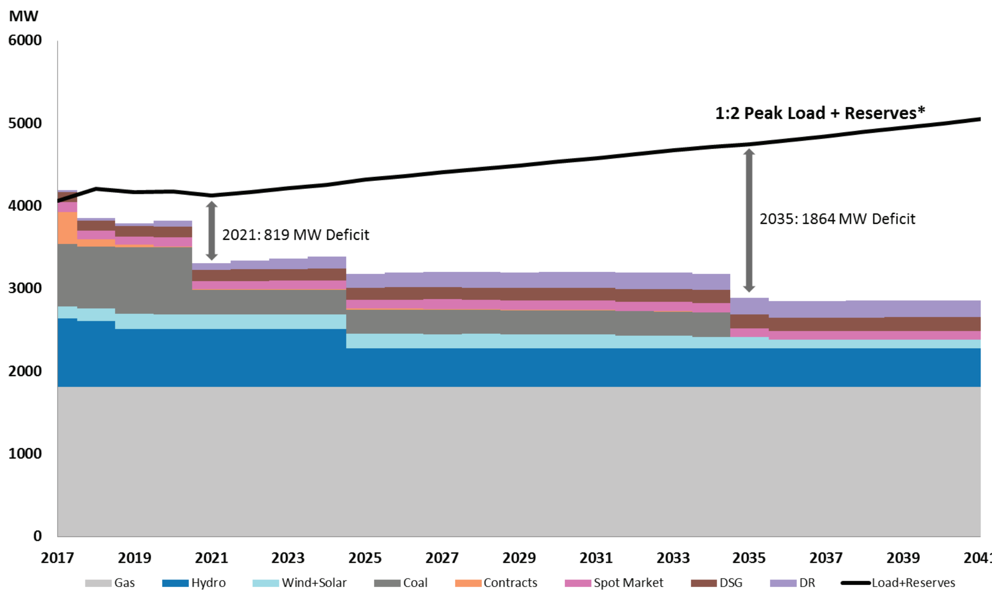
Integrated Resource Plan

NOVEMBER 2016

In 2021, after Boardman ceases coal-fired operations, PGE's capacity deficit is 819 MW. Figure ES-2 provides a summary of the capacity deficit from 2017 through 2041.

The capacity adequacy study is discussed in Section 5.1, Capacity Adequacy and Capacity Contribution.

FIGURE ES-2: PGE's estimated annual capacity need



*1:2 Peak Load adjusted for EE actions, excluding long-term opt-outs, including operating and planning reserves

Scenario Analysis

Methodology

PGE designed 23 portfolios to consider various resource strategy questions (e.g., RPS compliance timing) and to identify a Preferred Portfolio. PGE then evaluated the total cost of meeting customer demand with each portfolio under reference case assumptions, yielding the primary cost metric used throughout the IRP. To evaluate the price risks to customers, PGE also designed 23 potential future environments in which key variables deviate from their reference forecasts. These key variables include fuel prices, carbon prices, load growth, capital costs, hydro availability, and renewable resource performance. Risk metrics were designed to characterize variability (how much the cost may swing due to uncertain conditions), severity (how high costs may rise under worst case assumptions), and durability (how consistently well or poorly a portfolio performs relative to the other portfolios across the futures). These metrics are described in Chapter 11, Scoring Metrics.

September 12, 2018

TO: Jesse O. Gorsuch
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 155
Dated September 5, 2018

Request:

Please identify:

a. **Each PGE resource (physical, contractual, or otherwise) with a term length of one year or more that has expired or retired since 2001; and**
b. **The capacity (in MW) of each resource identified above.**

Response:

PGE objects to this request on the grounds that it is unduly burdensome and to the extent that it calls for a study or analysis that PGE has not performed. Notwithstanding its objection, PGE replies as follows:

Attachment 155-A provides a list of contracts, which were included in PGE's annual NVPC regulatory filings that have expired or been retired since 2001 and meet the following criteria:

- Power resources only (e.g., no gas storage, fuel contracts, or gas financial swaps); and
- At least 1-year term.

Attachment 155-A excludes the following:

- Electric financial swaps; and
- 1-year term contracts (i.e., electric physical instruments) used primarily for power hedging prior to the market shift towards using electric financial instruments.

Also note that the majority of these expiring or retiring resources have effectively been replaced in PGE's portfolio over time by other resources.

Attachment 155-A is protected information subject to Protective Order No. 18-047.

Page 2 of Cross-Exhibit AWEC/602 contains Protected Information and has been redacted in its entirety in accordance with Protective Order 18-047.

September 27, 2018

TO: Jesse O. Gorsuch
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 156
Dated September 21, 2018

Request:

Reference stipulating Parties/600, Page 6, line 15, to page 7, line2:

a. **Mr. Mullins' analysis assumed that the Schedule 129 transition adjustments, which are credited to non-participating customers separately through the system usage charge, would no longer be credited to non-participating customers if the direct access program did not exist. Is it PGE's position that non-participating customers would continue to recognize those transition adjustment credits if the direct access program did not exist? Please explain.**

Response:

a. No. PGE agrees that if the direct access program did not exist, then the Schedule 129 transition adjustments would cease to function as a credit to non-participating customers through the system usage charge, as stated. However, because the credit is allocated separately from actual production costs, its removal would have no effect on the total production costs listed in Tables 1 and 2 in AWEC Exhibit 400. Those tables incorrectly show the transition adjustment as an incremental cost to serve direct access customers. The variable and fixed production costs listed in columns 2 and 3 of the tables already include the share of production costs that would otherwise be paid by direct access customers if the direct access program did not exist. Thus, there would be no transition adjustment revenues to credit to non-participating customers nor would there be any transition charges to include for the direct access customers in the hypothetical analysis.

September 27, 2018

TO: Jesse O. Gorsuch
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 158
Dated September 21, 2018

Request:

Reference Stipulating Parties/600, Page 7, lines 5 and 6:

a. **Does PGE agree that the $39.86/MWh marginal cost of energy and $106.42/kW-year marginal cost of capacity values, which were used in Table 1 of Mr. Mullins Direct Access Testimony, correspond to the values calculated in PGE's marginal cost of generation study? If no, please explain.**

b. **Does PGE agree that the marginal cost of energy and capacity values used in the marginal cost of generation study represent long-term marginal costs and are not based on a first-year revenue requirement? If yes, please clarify the referenced statement. If no, please explain.**

Response:

a. PGE agrees with the $106.42/kW-year marginal cost of capacity value but does not agree with the $39.86/MWh marginal cost of energy value. This latter value does not include system line losses. See confidential work papers 'MC gen 2019 final_CONF.xlsx' for PGE's Exhibit 1200. The correct marginal cost of energy value is $37.42/MWh with line losses included. Thus, Table 1 in AWEC Exhibit 400 is overstating the incremental variable production costs to serve direct access customers in addition to incorrectly including transition adjustment revenues. As a result, the average energy cost stated in Table 1, column 3, is inflated.

b. Yes, PGE agrees. PGE's referenced statement was intended to express that the use of PGE's generation marginal cost study or Carty as the basis for the marginal cost of energy and capacity values is overstating the production costs that are included in Tables 1 and 2 in AWEC Exhibit 400. This analysis assumes that PGE would need to acquire additional resources to serve the load participating in the direct access program based on today's cost. However, PGE would have acquired additional resources throughout the direct access program's 16-year period if the program did not exist, and those resource acquisitions would likely have been at a lower cost. See Stipulating Parties Exhibit 600, Page 7, lines 12 through 14.

September 27, 2018

TO: Jesse O. Gorsuch
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 157
Dated September 21, 2018

Request:

Reference Stipulating Parties/600, Page 7, lines 12-13:

a. **Please provide workpapers supporting the assertion that Port Westward had a capital cost closer to $700/KW-yr.**

b. **Does PGE agree that the $700/KW-yr value it identified is over six times larger than the $106.42/kW-yr marginal cost of capacity assumed by Mr. Mullins in Table 1 of his Direct Access Testimony? If no, please explain.**

Response:

a. PGE inadvertently misstated the units for the overnight capital costs identified in Stipulating Parties Exhibit 600. Rather than $/kW-year, the units are $/kW. Errata pages to fix the error will be filed. Attachment 157-A provides the Port Westward revenue requirement work papers from 2007 that were used to calculate the $700/kW value. The gross plant in service was divided by Port Westward's 407 MW generating capacity to derive the capital cost value.

b. Yes, PGE does agree. However, the units are not comparable. As indicated in part (a), the units for the overnight capital costs should be in $/kW. Additionally, the marginal cost of capacity used in PGE's marginal cost study is based on a simple cycle combustion turbine. Port Westward is a combined cycle combustion turbine generating plant that provides both energy and capacity. The two costs are not directly comparable.

Port Westward Revenue Requirement
Dollars in $000s
Inputs in Yellow

	Order 07-015	
Revenue Requirement	42,105	Total Expenses + Utility Operating Income
NVPC	(8,915)	
O&M	8,440	
A&G	315	
Uncollectibles	223	.53% of Rev Req
Depreciation	8,679	
Property Taxes	-	
Franchise Fees	985	2.34% of Rev Req
Income Taxes	9,158	See Calc Below
Total Expenses	18,886	
Utility Operating Income	23,219	8.29% ROR * Rate Base
Check	23,219	Rev Req - Total Expenses
Gross Plant in Service	285,205	
Accumulated Depreciation	(4,340)	1/2 of 1st Yr Depr Expense
Accumulated Deferred Taxes	(1,758)	1/2 of 1st Yr Def Tax Expense
Net Plant in Service	279,107	
Working Cash	982	5.20% of Total Expenses
Rate Base	280,089	
Income Taxes:		
Revenues	42,105	
Book Expenses	9,727	
Interest	9,075	50% * 6.48% * Rate Base
Sch M	8,947	
State Taxable Income	14,356	
State Tax Expense @ 6.617%	950	State Taxable Income * 6.617%
Federal Taxable Income	13,406	
Federal Tax Expense @ 35%	4,692	Federal Taxable Income * 35%
Deferred Tax Expense	3,516	Sch M * 39.301% Composite Tax Rate
Total Income Tax Expense	9,158	State Tax Expense + Federal Tax Expense + Def Tax Expense

C:\Users\jog.DVC\Box\Client Files\3021-73\Settlement Docs\AWEC Objections to Partial Stip Re Direct Access\Cross Exhibits\[UE 335_AWEC DR 157_Attach A.xls]Sheet1

September 27, 2018

TO: Jesse O. Gorsuch
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 160
Dated September 21, 2018

<u>Request:</u>

Reference Stipulating Parties/600, Page 7, Line 19-Page 8, Line 3:

a. **Does PGE agree that Mr. Mullins explained that his assumption was due to the fact that resource additions are inherently blocky? If not, please explain your answer.**

b. **Please identify each combined cycle combustion turbine ("CCCT") manufacturer that PGE is aware of who offers an advanced CCCT model that is 236 average MW in nameplate or less and identify the model.**

<u>Response:</u>

a. Yes, PGE agrees. However, as stated in the referenced testimony, AWEC's analysis would be more appropriate had it used the unit cost of Carty rather than the total cost. Using the total cost assumes that an additional resource today would be necessary if the direct access program had not existed. However, if the direct access program had not been available for the past 16 years, PGE would have acquired additional resources during that period, and likely at a lower cost than that of Carty. Thus, using the unit cost instead of total cost would provide a more appropriate estimate that considers only the incremental cost for the additional direct access load to be served under cost of service. This would result in a lower total production cost than is listed in Table 2, column 3, in AWEC Exhibit 400.

b. In its 2016 IRP, PGE was not aware of a manufacturer who offers an advanced CCCT model that is 236 MW or less in nameplate capacity. Additionally, PGE does not agree with AWEC's premise that an additional resource would be necessary today if the direct access program had not existed during the past 16 years. For example, if the program did not exist, assumptions used in PGE's resource planning would have been different if the direct access load was included under cost of service.

Incremental Cost of Direct Access Program Using Various Assumptions

	Bundled Actual Cost		Incr. Cost to Serve Dir. Access Customers: Load / Demand MWh, KWh	MC Rate $/MWh, $/KW	Total Incremental Cost	Total Cost Without Dir. Access Program	
AWEC/500 Table 1							
Variable	$ 686,099		1,952,690	39.86	$ 77,838	$ 763,938	
Fixed	375,309		242,638	106.42	25,821	401,130	
Trans. Adj. Revs					18,170	18,170	
Total Production Cost	$ 1,061,408				$ 121,830	$ 1,183,238	
MWh	17,087,764				1,952,690	19,040,454	
$/kWh	**0.062**	(a)			0.062	**0.062**	(b)
Inc. Cost Ratio (b) / (a)						**1.0**	
With $37.42 Marginal Cost of Energy							
Variable	$ 686,099		1,952,690	37.42	$ 73,070	$ 759,169	
Fixed	375,309		242,638	106.42	25,821	401,130	
Trans. Adj. Revs					18,170	18,170	
Total Production Cost	$ 1,061,408				$ 117,061	$ 1,178,469	
MWh	17,087,764				1,952,690	19,040,454	
$/kWh	**0.0620**	(c)			0.0600	**0.062**	(d)
Inc. Cost Ratio (d) / (c)						**1.0**	
Without Transition Adjustment Revenues							
Variable	$ 686,099		1,952,690	37.42	$ 73,070	$ 759,169	
Fixed	375,309		242,638	106.42	25,821	401,130	
Trans. Adj. Revs					-	-	
Total Production Cost	$ 1,061,408				$ 98,891	$ 1,160,299	
MWh	17,087,764				1,952,690	19,040,454	
$/kWh	**0.062**	(e)			0.051	**0.061**	(f)
Inc. Cost Ratio (f) / (e)						**1.0**	