RECEIVED [X]
FILED [ ]
'96 JUN 14 AM 9 54
IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	:	
APPLICATION OF PACIFICORP	:	Case No. IPC-E-95-9
FOR AVOIDED COST	:	
METHODOLOGY FOR QUALIFYING	:	
FACILITIES LARGER THAN 1 MW	:	

Direct Testimony

of

Laren Hale

On Behalf of PacifiCorp

June 14, 1996

Q. Please state your name, business address and present position with PacifiCorp dba Utah Power & Light Company (PacifiCorp or the Company).

A. My name is Laren Hale, my business address is 825 NW Multnomah, Suite 625, Portland, Oregon 97232, and my present position is Senior Power Planner.

Qualifications

Q. Briefly describe your education and business experience.

A. I received an undergraduate degree in Business Finance and a Masters of Business Administration from the University of Utah. I began working for Utah Power & Light Company in 1979. During my 17 years with the Company I have held a variety of positions including Senior Cost of Service Analyst, Senior Pricing Analyst and Marketing Specialist. I assumed my current position in April of 1993.

Q. Please describe your current duties.

A. I am part of a team that prepares the Company's integrated resource plan (IRP). The Company's IRP is called Resource and Market Planning Program (RAMPP). The Company filed its fourth RAMPP report (RAMPP-4) with the Idaho Public Utilities Commission and other commissions in November, 1995. My specific duties include developing computer models of PacifiCorp's service territory including customer loads, transmission constraints, and existing and potential resources to serve customer needs.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the method developed by the Company to calculate IRP-based avoided costs. In addition I will discuss the updates that have been made to the RAMPP-4 computer model to bring the model current with existing market conditions.

Q. Would you describe the computer model that is used to calculate avoided costs.

A. The Integrated Planning Model (IPM) is a capacity expansion, linear programming model that selects future resources and dispatches all resources to minimize the present value of total resource costs. The model uses a 20-year planning horizon. An additional 30 years is also studied to incorporate the impact of end effects when selecting new resources. The additional 30 years is included to recognize the financial benefits of investments made in the last few years of the planning period.

Q. Was the IPM model used in the Company's most recent IRP process?

A. Yes. The Company licensed the IPM model in 1993 and has used it in the last two RAMPPs. However, the inputs used by the IPM model have been updated since the completion of RAMPP-4.

Updates to the RAMPP-4 Model

Q. Would you describe the updates that have been made to the RAMPP-4 model since the completion of RAMPP-4.

A. The updates are summarized in Exhibit 303 (LJH-1)

Q. Please describe Exhibit 303 (LJH-1).

A. The exhibit was prepared to demonstrate the changes that were necessary to update the RAMPP-4 model for use in the avoided cost study.

The exhibit has six columns. The second column describes the necessary update. The third and fourth columns identify the difference between RAMPP-4 and the avoided cost treatment. The fifth column identifies whether the update was mentioned in RAMPP-4 as an area that had changed since the inputs into RAMPP-4 had been established in early 1995. The RAMPP-4 report included a section in the Inputs Chapter called "Revisions to Inputs." This section reviewed known changes in input assumptions since the inputs were frozen for modeling purposes in early 1995. The sixth column provides useful information about the necessary change.

Q. Were these updates made in accordance with the settlement stipulation in this case?

A. Yes. All of the changes fall into one or more of the following categories:

(1) the changes were discussed as part of the settlement stipulation,

(2) the changes were needed to permit an IRP model to calculate avoided costs, or

(3) the changes were specifically discussed in RAMPP-4 as an update to the inputs.

Q. Would you describe Exhibit 304 (LJH-2)

A. Exhibit 304 (LJH-2) is comprised of pages 100 to 105 taken from the RAMPP-4 report, the "Revisions to Inputs" section of the Inputs Chapter. These pages discuss the changes that were known to have occurred since the RAMPP-4 inputs were frozen in early 1995. Most of the updates made to the RAMPP-4 model are described in these pages.

Q. Why weren't these known changes included in the RAMPP-4 model?

A. The RAMPP process progresses in stages. First, model inputs are determined, then model runs are developed, followed by analysis of the model runs. The inputs need to be frozen in order to have a consistent database through the completion of model analysis.

Q. The first change described in Exhibit 303 (LJH-1) is the number of run years. Why was this change necessary?

A. To keep model run times manageable, the Company required the model to select new resources for only 14 of the years in the 50-year period. The 14 years are called run years. In between run years, the model interpolates results to approximate the impact of resource selection. In the avoided cost study, the Company determined that the level of detail provided by only 14 run years was not sufficient. To calculate avoided costs using the IPM model, the Company included 25 run years, one run year for each of the first 21 years, then 4 run years during the 30 end effect years.

Q. If a QF wanted a twenty year contract to start in 1997 rather than 1996, would the model still require 25 run years?

A. No. The model would require 26 run years, 1996, the twenty years of the QF's contract 1997 to 2016, the year after the contract expires 2017, and four run years to calculate the end effects. Corresponding extensions would be required for any QF with an on-line year after 1996. Since the RAMPP-4 study period ends in 2015, the model would require extensive modeling revisions to extend the study years into the end effect years. These revisions are difficult and complicated to prepare. The Company will make its best effort to respond to a QF request in the 30 day period discussed in the settlement document in this case.

Q. The second item in Exhibit 303 (LJH-1) is the reduction of reserve margin from 12% to 10%. Why was this change needed?

A. 10% is consistent with the planning reserve margins the Company intends to use in RAMPP-5.

Planning reserve margins have declined since the 1980s when planning reserve margins were typically 20%. This decline is due to reduced construction lead time for supply-side resources, reduced rate of customer load growth, greater availability of low cost resources in the market place and ample surpluses available in WSCC.

Q. Item 3 of Exhibit 303 (LJH-1) states that DSM resources could be selected but DSM amounts have been locked for the avoided cost filing. Why was this done?

A. As part of the RAMPP process, representatives from various state commissions, agencies, intervenors and the Company discussed the appropriate DSM acquisition levels. The Company has committed to achieve 23 MWa of installed cost-effective savings by 1996; 25 MWa by 1997; and 28 MWa by 1998 as part of the RAMPP-4 action plan. Since the Company has committed to these DSM acquisitions, we do not feel it is correct to allow the model to select different DSM levels.

Q. The fourth item in Exhibit 303 (LJH-1) is Hermiston. Wasn't Hermiston included in the RAMPP-4 modeling?

A. Yes, Hermiston was included in RAMPP-4 modeling. In RAMPP-4 the Company assumed that Hermiston would not be completed in time for the Summer 1996 season. Current estimates are that Hermiston will be available for the Summer 1996 season and therefore should be included in the 1996 resources.

Hermiston is expected to go commercial on July 1 of this year. Hermiston began generating on March 31; April generation was 554 MWH, May was 69,662 MWH, and June is expected to be 105,000 MWH.

Q. The fifth, sixth and seventh items in Exhibit 303 (LJH-1) relate to natural gas. Are these the same prices discussed in Exhibit 304 (LJH-2) and on page 103 of RAMPP-4?

A. Yes. For RAMPP-4 the Company used the medium escalation rate. Since then, gas prices have declined. Therefore, for the avoided cost analysis work the Company used the low escalation rate and price discussed in RAMPP-4

Q. Items eight and nine of Exhibit 303 (LJH-1) relate to non-firm wholesale power prices and price escalation rates. Would you describe these changes.

A. Wholesale power prices have declined significantly from the levels used in RAMPP-4 and have declined even more than the 18 mills/kWh on-peak / 14 mills/kWh off-peak that was described in Exhibit 304 (LJH-2). The Company's wholesale marketing department has provided updated prices. The Company determined three index prices, namely a COB (California Oregon Border), Mid-Columbia and a Palo Verde price. The prices in mills/kWh are for an annual average delivery, based upon 12 months of future index values and provide for peak and off peak deliveries.

One year Wholesale Spot Power Prices

	RAMPP-4		Current Prices	
	On-peak	Off-peak	On-peak	Off-peak
COB	19.0	16.0	12.7	10.2
Mid Columbia	19.0	16.0	12.2	9.7
Palo Verde	19.0	16.0	13.8	8.3

As mentioned above, the Company has selected the low gas price escalation rate as an estimate of future gas price escalation. As in

RAMPP-4, the Company escalated wholesale market prices at 80% of the natural gas price escalation rate.

Q. Items ten and eleven of Exhibit 303 (LJH-1) relate to existing purchases and sales. Please describe these updates.

A. Since the inputs into RAMPP-4 were frozen in early 1995, the Company has entered into one new wholesale purchase, two seasonal exchanges and six new wholesale sales. For computer modeling purposes, each seasonal exchange requires a purchase to model the energy taken and a sale to model the energy delivered to the customer. Thus the IPM model has three new purchases and eight new sales since the RAMPP-4 inputs were frozen.

Two new purchases and seven new sales are discussed in Exhibit 304 (LJH-2). The third new purchase and the eighth new sale occurred because of a seasonal exchange with Black Hills which occurred after RAMPP-4 went to press.

An additional purchase has been added titled the 'Avoided Cost Unit.' The Avoided Cost Unit is the zero cost purchase used to calculate avoided costs. The size and delivery characteristics will vary with each QF project to be modeled.

In addition to the introduction of new purchases and sales, the Company has updated known changes to existing contracts. For example, the Company has notified BPA of our intent to reduce purchases under the BPA Peaking contract. The BPA Peaking purchase was reduced by 175 MW in the year 2000 consistent with this change.

Q. Item 12 of Exhibit 303 (LJH-1) relates to a potential market purchase. Is this an update of a resource in RAMPP-4?

A. Yes. The Company included a capacity purchase from the wholesale market in the RAMPP-4 portfolio of new resources. In RAMPP-4, the Market Purchase was priced like a simple cycle CT available at simple cycle fuel prices and with the natural gas fuel price escalation rate. In the avoided cost analysis, the Market Purchase has the same market price and price escalation rate as all of the other wholesale market short-term purchases. During the period 2003 to 2015, the model's selection of the Market Purchase has been constrained such that it represents no more than 50% of the total new supply side resources selected.

Q. There are three other updates mentioned in your Exhibit 303 (LJH-1). Please explain each update.

A. Item thirteen was the Arizona Public Service (APS) Sales. As mentioned in Exhibit 304 (LJH-2), the timing and availability of APS resources were under review by the Company when RAMPP-4 went to press. An APS simple cycle resource that was expected to be available in 1998 was eliminated. The APS Seasonal Sale and APS Seasonal Exchange were also adjusted to reflect current expected capacity, energy and timing. These changes in available resources would tend to increase avoided costs.

Item fourteen is Plant Re-rates. In RAMPP-4 the Company found that turbine upgrades were a cost effective method of providing more resources to the company. The timing and size of these turbine upgrades have been revised to current planning levels.

The final item in Exhibit 303 (LJH-1) is the Gadsby Repowering option. The Company has excluded the Gadsby Repowering option from the portfolio of new resources. The Gadsby Repowering option made calculation of avoided cost problematic. Repowering requires the conversion of an existing resource to become part of a new potential resource. The IPM model does not have an effective way to account for existing (sunk) costs. The elimination of this option has the impact of increasing avoided costs slightly since Gadsby costs were slightly lower than those for a cogeneration unit or a CCCT.

Q. Exhibit 304 (LJH-2) lists other items that have changed since RAMPP-4 inputs were frozen. Why were these items not updated in the model?

A. Two items were not updated: (1) Existing System: Wind Plants and (2) New Resources: Renewables. In each instance, the reference in Exhibit 304 (LJH-2) was informative in nature and did not require changes to the model.

Q. Were there any other items that the Company considered updating?

A. Yes. In RAMPP-4 the Company proposed that all new combustion turbines would be "F" technology. "F" technology turbines have been replaced by the newer "G" technology. The newer combustion turbines use advanced turbine blades to extract more energy during the first stage of the combined cycle. In addition to a superior heat rate, the newer combustion turbines have declined in cost primarily due to international competition and market conditions.

Although the Company did not make this update for this filing, we feel that keeping technology current is consistent with one of the goals of avoided cost. Quoting from the Idaho Staff's proposal, "One of the goals of this avoided cost methodology is to achieve a dynamic resource evaluation process that recognizes changes in loads, technologies, costs, availabilities, and economic conditions so that utilities' avoided costs are accurately determined." This item would not have had any noticeable impact on avoided cost rates.

Avoided Cost Calculation

Q. Please describe how avoided costs were calculated.

A. The development of the avoided costs follows the methodology in the settlement stipulation. The Company started with RAMPP-4 Case 13 which is the case used by the Company to determine the amount of DSM in the RAMPP-4 action plan. The Company developed a base case and an avoided cost case by making the updates mentioned above. The only modeling difference between the base case and the avoided cost case is the "Avoided Cost Unit." The Avoided Cost Unit is the zero cost purchase used to calculate avoided costs. Its characteristics will vary with each QF being priced. After completion of the two runs, relevant financial results are extracted from run outputs and read into an Excel spreadsheet to calculate the avoided costs.

Q. Please describe Exhibit 305 (LJH-3).

A. This Exhibit was prepared by me and consists of three pages showing the avoided cost calculation for 10, 20 and 40 MW, 100% capacity factor avoided costs units. The number in the bold box in the lower right hand corner is the Nominal Levelized Avoided Costs in $/MWH. For example in the 10 MW case, the nominal levelized avoided cost is $24.74 /MWH. Columns (A) and (B) are the Base Case and Avoided Cost Case annual expenses in thousands of dollars. Column (C) is the annual savings resulting from the avoided cost case. Column (D) is the nominal annual avoided costs in $/MWH.

Q. Why does Exhibit 305 (LJH-3) have results that continue past the 20 years which Staff has proposed as a standard QF contract term?

A. The avoided cost calculation includes end effect years in order to capture all of the impacts of the QF. Note that the IPM model shows negative avoided costs in the end effect years. The negative avoided costs is the result of a variety of offsetting savings and costs associated with the avoided cost unit. It should be noted that not all runs will have negative avoided costs savings in the end effects years.

Q. Does this conclude your testimony?
A. Yes.

Avoided Cost Filing
Updates to the IPM Model from RAMPP-4

Item No.	Update	RAMPP-4 Treatment	Avoided Cost Treatment	Changes discussed in R-4 Updates to the Inputs	Notes
1	Number of run years	14	25		20 planning years and five end effect years
2	Reserve Margin	12%	10%		Adjusted to current planning levels
3	DSM resources	Selectable	Locked		R-4, Case 13 with DSM costs reduced by 15%
4	Hermiston	1996	1997	X	On-line date
5	Natural gas 1996 price (¢/MMBtu)	155.1	124.5	X	Beginning 1996 price
6	Natural gas price escalation (Real % year)	2.11%	0.66%	X	Assumes inflation 3.3%/year
7	Natural gas transportation cost (¢/MMBtu)	46.5	35.3	X	For a Pacific NW CCCT
8	Wholesale market short-term prices ($/MWh)	19/16	12/09	X	On-peak/Off-peak
9	Wholesale market short-term price escalation(Real % year)	1.69%	0.53%	X	Assumes inflation 3.3%/year
10	Market purchases in existing system	26	31	X	5 new wholesale market purchases
11	Market sales in existing system	36	44	X	8 new wholesale market sales
12	Market purchase energy price	SCCT	Market	X	Price and escalation at short-term market rates
13	APS sales		Updated	X	Timing and capacity changed
14	Plant Re-Rates			X	Revised turbine upgrades
15	Gadsby repowering	Allowed	Not Allowed		Used CCCT instead to simplify modeling

Revisions to Inputs

PacifiCorp determined all of the key inputs to the model in early 1995, and then did the modeling for the 39 cases. Between early 1995 and late 1995 some of those inputs may have changed. This section identifies the changes that have occurred, and how each would affect the modeling results. The following discussion addresses updates in the following areas:

- Existing system: APS CTs
- Existing system: Hermiston
- Existing system: wind plants
- Existing system: plant re-rates
- Existing system: wholesale sales
- New resource: gas prices
- New Resources: renewables
- Non-firm market prices

<u>Existing System: APS CTs</u>

RAMPP-4 modeling included the APS CTs in the existing system beginning in 1998. They were part of the portfolio because they are part of an extensive agreement with Arizona Public Service company that includes many other components. The company is re-evaluating the timing for those CTs, discussing the issue with APS, and now expects delays in the timing of those projects. If the delay is 2-3 years, it would not affect the modeling results that peaking needs don't begin until 2002. Therefore, the company does not believe that this presents a problem for RAMPP-4 model results.

<u>Existing System: Hermiston</u>

As of May 1995, 60 percent of the engineering efforts were complete and 93 percent of the project purchase orders placed for the Hermiston project. PacifiCorp has initiated discussions with U.S. Generating Company regarding potential cost savings that may be available.

Existing System: Wind Plants

Both the Foote Creek and Columbia Hills wind projects are on track for completion and on-line status in 1996. Recent agreements with BPA and Kenetech clear significant hurdles in siting and building the projects. With both projects, PacifiCorp will be the majority owner and Kenetech will be the developer.

The United States House of Representatives Ways and Means Committee's latest budget proposal includes cutting the wind tax credit. PacifiCorp is working to keep the credit in effect. The company appreciates the importance of the credit to keep the current cost of wind power more competitive with alternative power sources. If the budget proposal without the credit is approved, it could threaten the viability of current and new wind projects. The company will be carefully watching the Committee's activities.

Existing System: Plant Re-Rates

Plant re-rates occur on an ongoing basis as plants undergo maintenance. Often different sources will report slightly different capacities; typically this is due to the use of different measurement standards. For example, the measurement may be on potential capacity, on a 30-minute output, or averaged over a longer time period. Any changes since early 1995 are small and would not affect the RAMPP-4 modeling results.

Existing System: Wholesale Sales

The company has made some new wholesale sales since performing the modeling for RAMPP-4. The significant fact for RAMPP modeling is that they all expire before the date of expected resource deficiency (2003), except for one 50 MW sale. New purchases of 71 MW help balance the sale and neutralize its impact on resource needs. Thus, recent wholesale activity should have no impact on the date of the company's need for new resources. Recent sales are listed below:

- City of Anaheim for 25 MW from 5/1995 to 10/1997
- Black Hills Power and Light for up to 60 MW from 10/1996 to 3/2002
- BPA for 100 MW from 8/1995 to 7/1998
- Cheyenne Light Fuel and Power for 145 MW from 6/1997 to 5/2000
- Eugene Water and Electric Board for 50 MW from 8/1995 to 7/2000
- Hinson Power for 140 MW from 4/1996 to 3/2001
- Springfield Utility Board for 50 MW from 10/1995 to 9/2015

In addition, the company has made two new wholesale purchases:

- BPA for 50 MW from 8/1995 to 7/1998
- City of Redding for 21 MW from 5/1995 to 5/2014

Information about the prudency of these contracts will be part of future rate case filings. Until the state public utility commissions decide the transactions are prudent in a rate case, there will be no price impact to customers.

New Resource Costs: Gas Prices

Current gas prices have declined from 155.1 to 124.5 ¢/MMBtu in the Mountain region and 131.6 c/MMBtu in the Pacific Northwest region. The medium gas price escalation rate has declined from 2.11 percent used in RAMPP-4 modeling to about 1.55 percent. Although lower, it is not as low as the low escalation rate used -- zero percent real escalation. However, the starting price has declined by about 19 percent in the Mountain region and by about 15 percent in the Pacific Northwest region. Table 3-25 shows the differences in assumptions used in the RAMPP-4 modeling and current market conditions. Since gas-fired resources were the least-cost supply-side resource under the original assumptions, lowering their cost does not change the ranking of resources.

Comparison between RAMPP-4 Forecast and Current Prices for Natural Gas

Table 3-25

		Current Market	RAMPP-4 Forecast	Difference
Raw Gas Price Including 1.5% Shrinkage				
Low Gas Price	Pacific NW	124.5	151.9	(27.4) ¢/MMBtu
Medium Gas Price	Pacific NW	124.5	155.1	(30.6) ¢/MMBtu
High Gas Price	Pacific NW	124.5	157.6	(33.1) ¢/MMBtu
Low Gas Price	Mountain	131.6	151.9	(20.3) ¢/MMBtu
Medium Gas Price	Mountain	131.6	155.1	(23.5) ¢/MMBtu
High Gas Price	Mountain	131.6	157.6	(26.0) ¢/MMBtu
Transport & Storage				
Simple Cycle (1)	Pacific NW	12.48	35.91	(23.43) /kW-year
	Mountain	19.91	21.51	(1.60) /kW-year
	Pacific NW	10.31	11.40	(1.09) ¢/MMBtu
	Mountain	5.37	5.20	0.17 ¢/MMBtu
Combined Cycle	Pacific NW	35.30	46.50	(11.20) ¢/MMBtu
	Mountain	23.50	20.70	2.80 ¢/MMBtu
Real Gas Price Escalation Rate				
Low Gas Escalation		0.66%	0.00%	0.66% / year
Medium Gas Escalation		1.55%	2.11%	-0.56% / year
High Gas Escalation		2.84%	3.78%	-0.94% / year
Real Transport & Storage Escalation Rate				
		0.00%	0.00%	0.00% / year

(1) Simple Cycle assumes 15% capacity factor. 11,300 BTU/kWh average heat rate.

A comparison between the low gas price case and the base case shows the major impacts of a decrease in the gas price and gas price escalation. Lower gas prices make gas-fired resources cheaper relative to other resources, which would result in the model's selection of more gas-fired resources and less DSM. Many of the DSM bundles would not be cost-effective at a 125 or a 131 ¢/MMbtu gas price. The model would also make fewer non-firm sales, and make more non-firm purchases. In spite of these changes in gas prices, and their expected impacts on modeling results, the company is not changing the amount of DSM in the RAMPP-4 action plan.

Coal prices have shown no significant change since early 1995.

New Resources: Renewables

A recent announcement by PacifiCorp is not directly related to the RAMPP-4 inputs, but is a significant development for the company's knowledge and experience with renewable technologies. PacifiCorp recently announced a joint venture with Bechtel to develop, own, and operate small renewable and distributed energy system projects in international markets as well as in the U.S. EnergyWorks will focus on specific markets for commercially available technologies: wind power, biomass-fueled power and cogeneration, small hydro, hybrid energy systems for remote and distributed power applications such as solar, and industrial energy efficiency services. The World Energy Council projects that approximately 145,000 MW of new electric generating capacity using renewable resources will be added to the global energy supply between 1991 and 2010. The initial focus of EnergyWorks is likely to be selected developing countries where the benefits of grid-supplied power are not readily secured, that have attractive business environments, and where growth in demand for power are greatest. The initiative will work with strong local partners in each country. PacifiCorp sees this type of business arrangement as best addressing customer needs, accelerating the company's understanding of the technology of PV and its economics, and developing the capability to provide such services in the U.S. when a viable business can be sustained.

Non-Firm Market Prices

Wholesale prices have declined slightly since early 1995. The company believes they may be one to two mills lower than the levels used in

RAMPP-4 modeling, or around 18 mills on-peak and 14 mills off-peak. The reader can look at the case with 25 percent lower non-firm market prices for an estimate of the impact of lower non-firm market prices. The primary impact would be lower revenues for the company and higher retail customer prices. It would have very little impact on resource choices.

The company has concluded that, in spite of some changes in inputs since the RAMPP-4 modeling, none of the changes warrant changing the action plan.

The next chapter covers the modeling results for RAMPP-4. It reviews the input assumptions and results for each of the individual cases.

Idaho Avoided Cost Filing
10 MW Avoided Cost Unit

	Annual Expense $000			$/MWh
	Base Case (A)	with AC Unit (B)	Savings (C) (A)-(B)	Annual (D) (C)/8.76/10
1996	1,044,540	1,043,279	1,261	**14.40**
1997	1,088,558	1,087,205	1,354	**15.45**
1998	1,130,265	1,128,916	1,350	**15.41**
1999	1,204,550	1,203,157	1,393	**15.90**
2000	1,306,315	1,304,057	2,258	**25.78**
2001	1,370,028	1,367,658	2,370	**27.06**
2002	1,482,374	1,479,881	2,492	**28.45**
2003	1,603,997	1,601,615	2,382	**27.19**
2004	1,708,525	1,706,075	2,450	**27.97**
2005	1,811,825	1,809,300	2,526	**28.83**
2006	1,956,485	1,953,891	2,594	**29.62**
2007	2,072,007	2,069,288	2,719	**31.03**
2008	2,225,637	2,222,811	2,826	**32.26**
2009	2,383,987	2,381,175	2,812	**32.10**
2010	2,583,156	2,580,140	3,015	**34.42**
2011	2,765,912	2,762,877	3,034	**34.64**
2012	2,929,033	2,925,890	3,143	**35.88**
2013	3,095,108	3,091,852	3,256	**37.17**
2014	3,293,159	3,289,792	3,367	**38.44**
2015	3,502,895	3,499,409	3,486	**39.80**
2016	3,661,147	3,661,240	(92)	**-1.05**
2020	4,187,221	4,187,345	(124)	**-1.41**
2024	4,771,352	4,771,493	(140)	**-1.60**
2031	5,990,363	5,990,539	(177)	**-2.02**
2038	7,520,812	7,521,034	(222)	**-2.53**
2045	9,439,892	9,440,170	(278)	**-3.18**
Nominal Levelized Avoided Cost at 8.7%				$\boxed{24.74}$

Idaho Avoided Cost Filing
20 MW Avoided Cost Unit

	Annual Expense $000			$/MWh
	Base Case	with AC Unit	Savings	Annual
	(A)	(B)	(C)	(D)
			(A)-(B)	(C)/8.76/20
1996	1,044,540	1,042,018	2,522	**14.40**
1997	1,088,558	1,085,851	2,707	**15.45**
1998	1,130,265	1,127,567	2,698	**15.40**
1999	1,204,550	1,201,761	2,789	**15.92**
2000	1,306,315	1,301,798	4,517	**25.78**
2001	1,370,028	1,365,337	4,691	**26.78**
2002	1,482,374	1,477,389	4,984	**28.45**
2003	1,603,997	1,599,233	4,764	**27.19**
2004	1,708,525	1,703,624	4,901	**27.98**
2005	1,811,825	1,806,766	5,059	**28.88**
2006	1,956,485	1,951,296	5,189	**29.62**
2007	2,072,007	2,066,585	5,421	**30.94**
2008	2,225,637	2,219,987	5,650	**32.25**
2009	2,383,987	2,378,362	5,625	**32.11**
2010	2,583,156	2,577,135	6,021	**34.36**
2011	2,765,912	2,759,843	6,069	**34.64**
2012	2,929,033	2,922,747	6,287	**35.88**
2013	3,095,108	3,088,596	6,512	**37.17**
2014	3,293,159	3,286,425	6,734	**38.43**
2015	3,502,895	3,495,923	6,972	**39.80**
2016	3,661,147	3,661,332	(185)	**-1.05**
2020	4,187,221	4,187,462	(241)	**-1.37**
2024	4,771,352	4,771,633	(281)	**-1.60**
2031	5,990,363	5,990,716	(353)	**-2.01**
2038	7,520,812	7,521,255	(443)	**-2.53**
2045	9,439,892	9,440,448	(556)	**-3.17**
Nominal Levelized Avoided Cost at 8.7%				**24.72**

Idaho Avoided Cost Filing
40 MW Avoided Cost Unit

	Annual Expense $000			$/MWh
	Base Case (A)	with AC Unit (B)	Savings (C) (A)-(B)	Annual (D) (C)/8.76/40
1996	1,044,540	1,039,496	5,045	**14.40**
1997	1,088,558	1,083,143	5,415	**15.45**
1998	1,130,265	1,124,908	5,358	**15.29**
1999	1,204,550	1,199,045	5,505	**15.71**
2000	1,306,315	1,297,293	9,022	**25.75**
2001	1,370,028	1,360,695	9,332	**26.63**
2002	1,482,374	1,472,405	9,969	**28.45**
2003	1,603,997	1,594,466	9,530	**27.20**
2004	1,708,525	1,698,738	9,787	**27.93**
2005	1,811,825	1,801,717	10,108	**28.85**
2006	1,956,485	1,946,107	10,377	**29.62**
2007	2,072,007	2,061,208	10,799	**30.82**
2008	2,225,637	2,214,339	11,298	**32.24**
2009	2,383,987	2,372,736	11,251	**32.11**
2010	2,583,156	2,571,114	12,041	**34.36**
2011	2,765,912	2,753,774	12,138	**34.64**
2012	2,929,033	2,916,459	12,574	**35.89**
2013	3,095,108	3,082,098	13,010	**37.13**
2014	3,293,159	3,279,692	13,467	**38.43**
2015	3,502,895	3,488,950	13,945	**39.80**
2016	3,661,147	3,661,558	(411)	**-1.17**
2020	4,187,221	4,187,673	(452)	**-1.29**
2024	4,771,352	4,771,873	(521)	**-1.49**
2031	5,990,363	5,991,016	(654)	**-1.87**
2038	7,520,812	7,521,633	(821)	**-2.34**
2045	9,439,892	9,440,922	(1,030)	**-2.94**
Nominal Levelized Avoided Cost at 8.7%				**24.69**

CERTIFICATE OF SERVICE

I hereby certify that on the 13th day of June, 1996, a true and correct copy of the foregoing Direct Testimony of Laren Hale was sent via Federal Express to the following:

Larry D. Ripley
Idaho Power Company
P.O. Box 70
Boise, Idaho 83707-0070

Barton L. Kline
Idaho Power Company
P.O. Box 70
Boise, Idaho 83707-0070

Brad Purdy
Deputy Attorney General
Idaho Public Utilities Commission
P.O. Box 83720
Boise, Idaho 83720-0074

Thomas Dukich, Manager
Washington Water Power Co.
P.O. Box 3727
Spokane, Washington 99220

R. Blair Strong
Paine, Hamblen, et al.
717 W. Sprague Avenue, #1200
Spokane, Washington 99204

Gregory N. Duvall
PacifiCorp
825 NE Multnomah, Suite 485
Portland, Oregon 97202

Peter J. Richardson
Davis Wright Tremain
999 Main Street, Suite 911
Boise, Idaho 83702

Carl Myers
Myers Engineering, P.A.
750 Warm Springs Avenue
Boise, Idaho 83712

Ronald C. Barr
Earth Power Resources, Inc.
2534 East 53rd Street
Tulsa, Oklahoma 74105

Richard B. Burleigh
Don Olowinski
Stephanie Walter Gillette
Hawley Troxell Ennis & Hawley
P.O. Box 1617
Boise, Idaho 83701-1617

Owen H. Orndorff
Orndorff Peterson & Hawley
1087 West River Street, Suite 230
Boise, Idaho 83702-7035