RECEIVED ☑
FILED ☐
2004 FEB 19 PM 3:32
IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO THE STATE OF IDAHO	))))))	CASE NO. IPC-E-03-13

Direct Testimony of

Don C. Reading, Ph.D.

Ben Johnson Associates, Inc.

on behalf of

Industrial Customers of Idaho Power (ICIP)

February 19, 2004

Introduction

Q. Would you please state your name and address?

A. Don Reading, Ben Johnson Associates, Boise, Idaho

Q. Have you prepared an appendix that describes your qualifications in regulatory and utility economics?

A. Yes. Appendix A, attached to my testimony, serves this purpose.

Q. Does your testimony include any attachments?

A. Yes. Attached are Exhibit 201: Danskin Station Costs; Exhibit 202: Danskin Generation Summary; Exhibit 203: Mtn. Home Generation Station; Exhibit 204: Mid-Columbia Prices; Exhibit 205: Proposed Change in Fixed and Energy Charges.

Q. What is your purpose in making your appearance at this hearing?

A. Our firm has been retained by the Industrial Customers of Idaho Power (ICIP) to assist in the evaluation of Idaho Power's (Company, IPCo) rate application. General rate applications are usually complex, and that is certainly true of this one. I have review the Company's testimony and exhibits, as well as the discovery filed by the interveners and responses by the Company. My testimony will be focus only on several significant issues. Silence on other issues does not imply acceptance of the Company's position.

Q. Would you please describe how your testimony is organized?

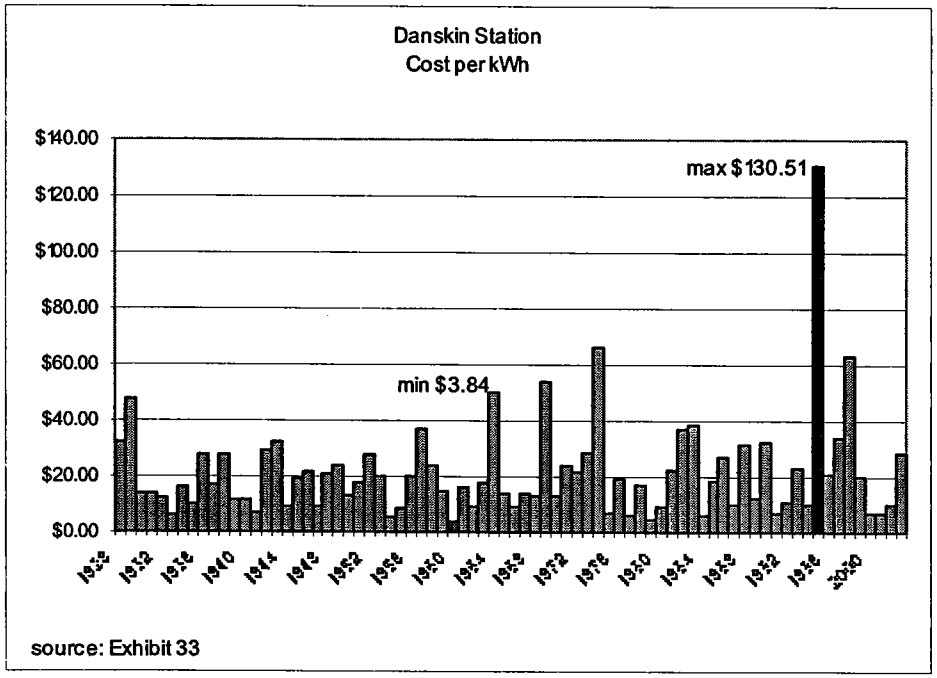
A. Yes. Following this introduction, my testimony has two major sections. The first section deals with the costs and assumed operating hours of the Company's Danskin Station Generating Facility. The second section discusses how system loads on Idaho Power's system have changed dramatically over the past ten years with an increased focus on peaks on the system.

Danskin Station

Q. Let's turn to your first major section, which is the impact on proposed rates from the inclusion of Idaho Power's Danskin Generating Station located in Mt. Home. Based on the Company's exhibits did you examine the contribution of the Danskin Station to generating resources?

A. Yes. Company Exhibit 33 estimates power supply costs and the output of all Idaho Power's current generation assets given current system demand for each year for the period 1928 through 2003. The output and power supply costs are thus normalized over the 75 year period for the water conditions that existed for that given year. An average is calculated that would represent the mean or expected output and power supply costs under normal water conditions to meet native load. Danskin Station's normalized average annual output over this 75 year period is 804.6 Mwh or the equivalent of just 8.9 hours per year. (Exhibit 33, page 1 of 77; hours based on 90 MW) At this output, the fuel costs including the Fixed Capacity Charge - Gas Transportation, are $3.267 million. If you add the annual capital costs of $7.728 million (Idaho Power Company, Application p. 7. "The annual revenue requirement associated with the construction of this peaking generating resource is $7,727,782.") This leads to an average normalized annual cost of $10.995 million. The normalized average cost per kilowatt hours basis (kWh) (<u>not MWh</u>!) is $13.65.

3 Chart 1



In fact, as shown in the Chart 1 above and in Exhibit 201 over the normalized 75 year period the highest Mwh production from Danskin Station was found by the Company to be 2,886.3 in 1960 for a cost of $3.84 per kWh for that year. The highest is $130.51 in 1995.

Q. Could you briefly describe the Danskin Generation Station?

A. The generating plant consists of two (2) natural gas-fired combustion turbines rated at approximately 45 MW each (Unit #2 and Unit #3). It is located about two miles from Mountain Home, Idaho and first produced power in September 2001. It is supplied by gas from the Williams Northwest Pipeline located near the plant. Due to air quality standards the plant is limited in operations to 5,140 hours per year.

Q. The Plant has been in operation since the fall of 2001. What has been the actual output of the facility?

A. The first unit (which is actually called unit #2) first produced power on September 25, 2001, followed by an on line date five days later by unit #3. (Idaho Power Company's Response to 3rd Production Request of Commission Staff, page 34.). For calendar 2002, the first full year of operation, output from Danskin was 43,368 Mwh (FERC Form 1, 2002, page 403). Production costs that are listed for calendar 2002 are $5.14 million, which yields a running cost of 11.85 cents per kWh. However this does not include the annual capital costs of $7.7 million. When capital costs are included, the running costs go up to 29.7 cents per kWh.

It should be remembered --- and an economists' favorite saying -- sunk costs are sunk. From the Company's prospective (and economically rational once the plant is built) the annual amortized cost of $7.7 million doesn't matter in deciding when to operate the plant. As long as the variable costs -- primarily natural gas prices for a unit like this -- are covered by the market value of power, it will be rational to run the plant. The variable costs of the power produced from Danskin have varied between 60.2 cents per kWh in 2001 and 29.7 cents per kWh in 2002. However, ratepayers in this case are being asked to shoulder the burden of the capital costs in their rates. From the ratepayers' prospective therefore, the full cost – both variable and fixed – is the relevant cost.

Q. How do the costs you discussed above compare to what the Company told the Commission in their application for a Certificate of Public Convenience and Necessity (CPCN) about the operation of the plant?

A. In its CPCN Application the Company described the expected operating costs of Danskin Station as follows:

> The preliminary estimate of the levelized cost per megawatt hour (MWh) would range from an upper level of $223 per MWh based on a capital cost for the Station of $55.2 million, 500 hours of annual generation, and levelized fuel costs of $5.05 per MMBtu over the 30-year life of the Station, to a lower range cost of $77 per MWh based on a Station cost of $46 million, 5,140 hours of annual dispatch, and average fuel costs of $5.05 per MMBtu. (Idaho Public Utilities Commission Order No. 28773, Case No. IPC-E-01-12, July 11, 2001, page 5.)

This means that the actual cost of 29.7 cents per kWh for 2002 was 33% higher than the highest estimated cost, and 385% higher than the lowest estimate. It should be remembered that 2002 was a low water year when output of the plant would be expected to be high and hence one would expect the cost per kWh to be on the low end of the range.

Q. How does the estimated cost range for Danskin output found in the Company's CPCN compare to the normalized range presented by the Company in this case?

A. As shown above and in Exhibit xx the normalized range of output and demand over the 75 year period presented by the Company in this case varies from a low of $3.84 per kWh to a high of $130.51 per kWh. This translates into 1,285% higher than actual on the low end to 43,943% higher on the high end. So both the actual and expected costs significantly exceed what the Company told the Commission they expected would be the costs to ratepayers for the output of this plant when they applied for their CPCN.

Q. Based on the information presented to it by the Company did the Commission authorize the construction of Danskin Station?

A. Yes. However in its Order authorizing the plant, the Commission expressed discomfort about the amount of information provided by the Company.

> The Company needs to provide the Commission with more information. What other alternatives were considered? What was

> the Company's forecasted need? The Company expressed concern that we will assess its decision to build based on hindsight and from a perspective of changed market conditions. We assure the Company that the review standard employed by the Commission will be what Company knew or should have known at the time it made its decision to build. (IPUC Order No. 28773, page 13.)

Q. The Company offered and the Commission accepted a "Commitment Estimate" for the capital cost portion of the plant. Did the final cost of the facility fall at or below that estimate?

A. Idaho Power Committed that capital costs would not exceed $55.2 million. According to the Company's Application in this case the cost of construction was "approximately $49 million". This construction cost has led to the Company's request for the annual revenue requirement of $7,727,782 associated in the investment in the Danskin Power Plant. (Application, page 7.)

Q. If the investment costs for Danskin Station were lower than the "Commitment Estimate" why are the actual operating costs and the expected normalized costs so much higher?

A. As shown above, Idaho Power based its operating estimates for running the plant on an assumption that it would run between 500 and 5,140 hours per year. Even though the last 2 years have been exceptionally dry, the plant has only been on line at the low end of the estimated range.

> Unit #2 was first synchronized at 18:55 on 9/25/01. Between that date/time and the end of the month of October 2003, unit #2 operated for a total of 1,268 hours. Unit #3 was first synchronized at 21:27 on 9/30/01. Between that date/time and the end of the month of October 2003, unit #3 operated for a total of 1,235.3 hours. Between 18:55 on 9/25/01 and the end of October 2003, at least one unit was on line for a total of 1,714.58 hours. (Idaho Power Company's Response to 3rd Production Request of Commission Staff, Response to Request No. 86, pages 34,35.)

This means Unit #2 has averaged 634 hours annually over the last two years, while Unit #3 has averaged 617.65 hours annually. For the combined units at least one was on line for an annual average of 857.29 hours. The estimate is close to the low range of 500 hours however is only 1/6th the high range. With capital costs fixed at $7.7 million per year plus the fixed capacity charge for gas transport of $3.2 million the annual fixed costs of the plant are $10.9 million. Therefore the cost of production on a kWh basis are highly dependent on the number of hours the facility is in operation. It appears that even in dry years, like the last two, the plant will not be run in a range that will produce power at a reasonable cost.

Q. The Company estimates the cost of output from Danskin from a low of $3.84 per kWh to a high of $130.51 per kWh. Why are these costs so much higher than predicted by the Company and which were used as the basis for the Commissions approval?

A. Based on both actual operations and expected needs, the hours of operation are significantly less than the Company claimed in its application.

> For the immediate future, Idaho Power indicates that it intends to operate the Station 5,140 hours per year, i.e., up to the limit allowed by its air quality permit. Once the Garnet project comes on line in 2004, however, the role of the Mountain Home Station, Staff states, could change. (IPUC Order No. 28773, page 7.)

Therefore, the Company expected the plant to be on line for over 5,000 hours through 2004. In reality the plant has operated only 2,686 hours since its only line date through December 2003. (Idaho Power Company's Response to the 1st Production Request of ICIP, Response to Request No. 53,54. see Exhibit 202) This means the plant has operated just over half the claimed hours in the *past 2 and 1/3 years*. Because the hours of operation have been so limited the cost of output on a kWh basis is very high.

Q. Did Idaho Power intend the Danskin Plant to fill native load or for off system sales?

In a response to a Staff Production Request in Case No. IPC-E-01-12 (the CPCN application) the Company stated;

> Idaho Power is proposing to develop the Mountain Home Generation Project to serve the needs of Idaho Power's native load customers. There may be times when all or a portion of the Station's generation is surplus to the needs of Idaho Power's native load customers. (Idaho Power Company's Response to the First Production Request of the Commission Staff, Case No. IPC-E-01-12, Response to Request No. 8.)

While that may be true, the number of hours from the facility needed to serve native load is low and thus the cost is high. In response to an ICIP production request, the Company provided a Mtn. Home Generation Station Operating Plan dated July 7, 2001 – just before the Commission issued its CPCN for the plant. (Idaho Power Company's Response to First Production Request of the ICIP, Response No. 57; Exhibit 203) This document indicated expected operating hours for the plant to be 3,673 for the last 5 months of 2000; 4,344 for 2001; 2,952 for 2002, 1,682 for 2003, and just 848 for 2004 and 2005. These are significantly less that the 5,140 hours in the 'immediate future' that Idaho Power presented to the Commission.

Q. Do you know why the hours of operations of Danskin Station have been so limited?

A. The Company probably assumed it would use the plant for secondary sales as well as to meet native load needs. This would mean the plant would be on line sufficient hours to bring the costs on a kWh basis in line with what the Company expected would be the costs of power.

> Idaho Power's marketing and trading analysts have indicated that annual heavy load period market prices for the next few years will likely be in the range of $50 to $350 per MWh. The estimated forward price is approximately $350 per MWh for April 1 through March 2002. The five to ten years forward prices currently are in the range of $55 per MWh. Hourly prices have historically been several times the annual average and could be in excess of $1000 per MWh in the near term. (Idaho Power Application, Case No. IPC-E-01-12, page 4.)

Note this reference is to the Company's marketing and trading arm. In reality prices in the secondary market have not been as high as they predicted. What is irrational about the Company's estimates is that the upper range could be sustained for an extended period of time. At prices equal to 35 cents per kWh the market would be expected to adjust with customer curtailments and fuel switching. Even if Danskin would have been on line the full 5,140 hours per year, market prices would need to be above $77 per MWh for the plant to be cost effective for secondary sales.

Q. You indicated that Danskin would be used for secondary sales as well as to meet native load needs. What has been the experience since the plant came on line?

A. The Company does not specifically identify any generation resource when making off system sales. However the Company, in a good faith effort to respond to the ICIP's production request, did provide estimates based on operating parameters of their system.

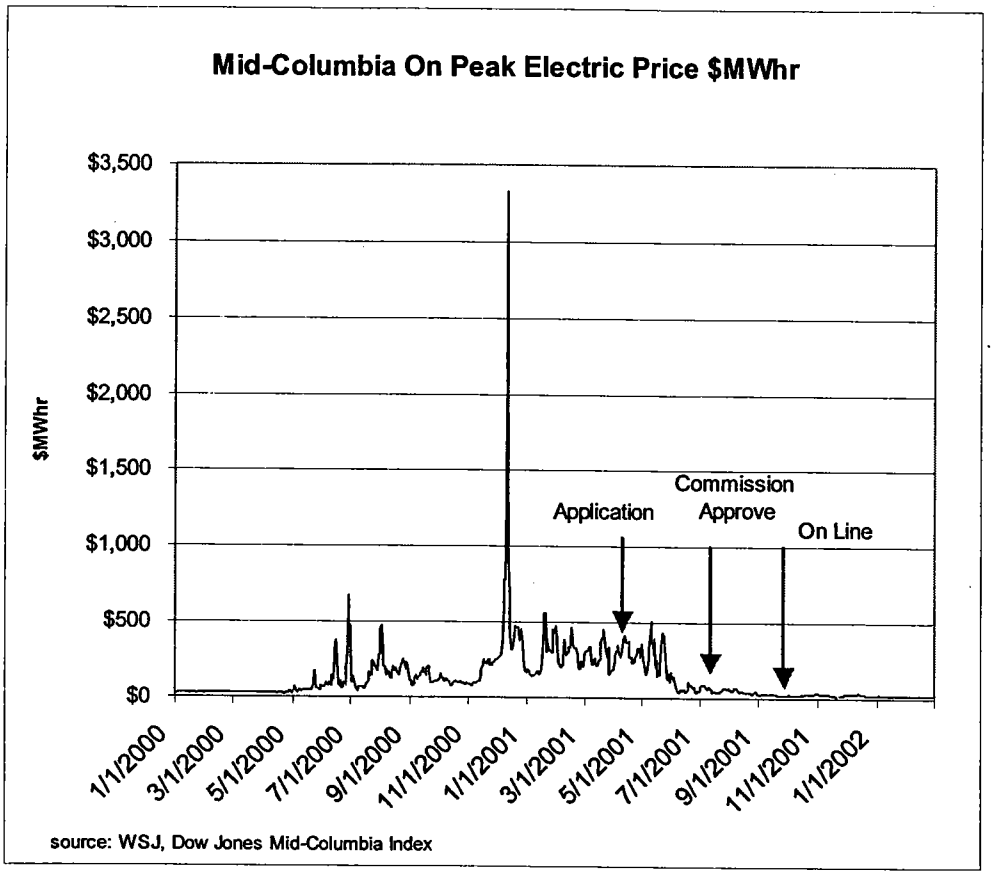
> However, because Danskin is the highest cost Company-owned resource and in order to make a good faith effort to respond to this request, in the attached information the Company has assumed that in any hour that the Company was a net purchaser, generation from Danskin was used to serve native load; and conversely, in any hour that the Company was a net seller, generation from Danskin was generated for off system sales. (IPCo Response the 1st Production Request of the ICIP, Response 53,54.)

The results of that modeling effort indicate Danskin Station produced 106,192 MWh from its on line date in the fall of 2000 through the end of December 2003. (See Exhibit xx.) Of that amount 78,452 MWh or 73.9% were assumed to serve for native load. It is apparent that estimates of operating hours for Danskin for off system sales have not developed. For example for 2003 the estimate of generating for off system sales was only 2,655 hours.

Q. Wouldn't it be fair to look at the decision in the context of the chaos in the energy markets in 2000 and 2001?

A. Certainly. The turmoil in energy markets during 2000 and the first half of 2001 are well known. In the fall of 2000 and early 2001 the Company had engaged in several programs to obtain power, including industrial and irrigation buy backs in order to obtain power needed to serve load. As indicated in the Chart 2 (Exhibit 204, page 1.) below prices for electricity on the market reached unprecedented levels in December 2001 and remained high through the spring of 2001.

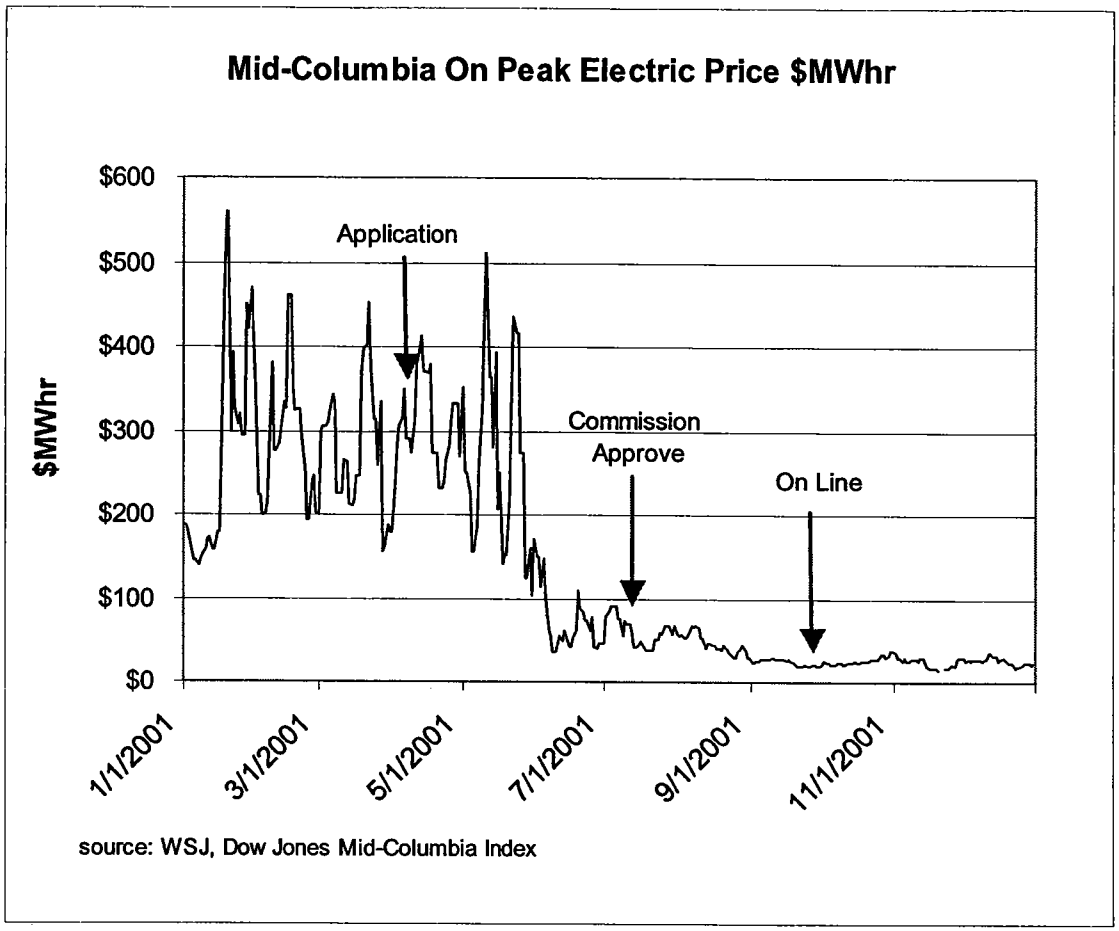
Chart 2



Q. In Chart 2 you have indicated when the application for Danskin was filed, when the Commission approved the CPCN, and the on line date. It looks like market prices had changed dramatically by the time the Commission issued its Danskin CPCN Order. Could you explain?

A. Chart 3 (Exhibit 204, page 2.) below shows for the year 2001 the Dow Jones Mid-Columbia Index, application date, Commission approval, and the on line date for Danskin.

Chart 3



Note that by the time the Commission approved the CPCN market conditions had changed dramatically and by the time the plant came on line the price for market power was back to pre-2000 levels. This meant the ability to run the plant and make a profit diminished even when including only the variable expenses and not the fixed costs. It also shows that prices were not remaining at the $350 per Mwh through March 2002 as predicted by Idaho Power's marketing and trading analysts. This should have a warning to the Company that they needed to reassess the economic viability of the plant. As discussed above, the Commission had asked for more information and documentation about the facility. It would have been wise for the Company to reassess at the time of the

Commissions approval. Even if there had been expenditures up to that date, the Company could have come to the Commission for ratemaking treatment. That would have been a better choice than now asking ratepayers to assume the costs of a plant that will sit idle most of time.

Q. What type of ratemaking treatment are you referring to?

A. The Company could have ceased construction and sought recovery of its then sunk costs.

Q. Did the Danskin Generating Station fit within the Company's Integrated Resource Plan (IRP)?

A. Idaho Power acknowledged during the application process that Danskin was not part of their IRP.

> Idaho Power acknowledges that the Mountain Home Station is not identified in the Near-Term Action Plan in the Company's 2000 IRP. Nevertheless, Idaho Power believes that construction of the Station is consistent with the IRP. The Station provides a cost-effective alternative to planned wholesale market purchases. Idaho Power believes that recent market prices for purchased power create a unique circumstance to be addressed for the 2001-2004 period. (Idaho Power Application, Case No. IPC-E-01-12, page 4.)

The Commission in approving Danskin recognized what it characterized as 'volatility' in the electric spot market that could mean deviation from the IRP would be justified. However the Commission also firmly stated there was not sufficient information available to make a least cost decision.

> We are convinced that the volatility of the electric spot market created a situation that justified a deviation from the Company's 2000 IRP and its actions in developing plans for the Mountain Home Station. The information provided however is insufficient to determine the reasonableness of the related costs. As reflected

> in Staff comments, it is unknown whether the Mountain Home Station was the least cost alternative. Because the Mountain Home Station was not selected pursuant to a RFP process, we are unable to conclude based on the information provided that the commitment estimate is reasonable. The Company in its Application, we note, also provides no comparison of alternatives (alternatives available but not chosen). As reflected in its comments, Power Development Associates believes it offered the Company a better project. Communication and timing appear to be factors in the Company's decision to proceed with its own project. It also appears that the Company's choice of equipment may be better suited to later conversion to combined cycle. There is no record as to whether other alternatives were also considered and rejected. We are unconvinced that the best measure of the cost of alternative resources is market price estimates in effect at the time the decision to proceed was made. The record supporting such a finding remains to be developed. (IPUC Order No. 28773, page 12.)

It appears the Commission skepticism has been proven by time. As shown in Chart 3, 2002 market conditions had already changed by the time the Commission gave its approval in July of 2001.

Q. How has Idaho Power Company responded the Commissions skepticism and the lack of an alternative to Danskin?

A. Idaho Power apparently rushed the project in response to then-current market prices and the potential benefits of generation.

> In summary, given high market prices for power and the extremely high demand for turbines at the time, the sooner a combustion turbine project could be constructed, the greater its value. While the Commission's Order No. 28773 tended to minimize high current market prices as a justification for constructing the Danskin Project, it must be remembered that <u>at the time</u> no one was sure what market prices would be in the future. At the time, FERC was continuing to refuse to impose hard market caps in the West and its public pronouncements repeated the market would be permitted to operate to take care of the energy supply problem. At the time, the

> prospect for continuing high market prices as very real. Considering the market prices experienced at the time of the decision to proceed with Danskin, potential customer cost savings from a project like Danskin were on the order of $10 to $20 million per month. (IPCo Response to 4th Production Request of Commission Staff, Response 88.)

As indicated in the Charts above, at the time the Commission approved the plant, prices-- while high by today's standards -- were different than in the proceeding months of extremely high prices. These changing market conditions should have given the Company pause and caused them to take a new look at the plant before attempting to saddle ratepayers with a fixed cost of nearly $11 million per year for limited output at outrageous costs.

Q. The Company has recently received a CPCN for the Bennett Mountain generating facility. When this peaking plant becomes part of Idaho Power's system how is it expected to effect the operation of Danskin Station?

A. As indicated by the Company above, Danskin is Idaho Power's highest cost resource. The will not change with addition of Bennett Mountain to Idaho Power's generating resource portfolio:

> Both plants are intended to meet Idaho Power's peak load requirements in the summer and winter daytime hours. With the Bennett Mountain plant not yet online, the Danskin plant operated slightly more than 500 hours during 2002, and operated approximately 475 hours through September of 2003. Both years have been considered low water years in which above normal thermal generation and market purchases have been required. Since first going online in August 2001, Danskin has operated in all but two months. Once Bennett Mountain becomes available, however, Danskin will likely operate far less hours. Both plants will need to be operated at times during the summer daytime hours, but still, Staff believes Danskin's operation could easily be cut in half from its current operational level. (IPUC Staff Comments, Case No. IPC-E-03-12)

At 500 hours the full cost of output to ratepayers from Danskin is about $0.25 per kWh. However staff estimates that it will run 'far less' and the output 'easily' cut in half. At 250 hours per year the cost per kWh is 48.8 cents. Remember this is the estimate for the driest years, on average -- according to the Company's filing the plant on average produced about 800 MWh. At half this amount or 400 MWh per year the plant costs to ratepayers on a per kWh (again NOT MWh) will be $27.46 after Bennett Mountain comes on line.

Q. What recommendations do you have for the Commission in dealing with the very high cost the Company is asking ratepayers to shoulder in relation to the Danskin Generating Station?

A. Certainly market conditions have changed, but the magnitude of the cost difference that the Company is asking ratepayers to pay and the exceptions presented to the Commission are huge and it is unreasonable to expect ratepayers to pay this amount. The Company did have the alternative of reassessing, but pushed ahead even while the market prices were declining.

I recommend the Commission not give the Company rate base treatment for Danskin Station. This recommendation is especially compelling since the Company is going ahead with the Bennett Mountain plant which will cause Danskin to run even less.

Q. If the Commission followed your recommendations would the Company need to write-off the full costs of the facility?

A. There certainly would be significant costs. However the Company has indicated the generators could be sold.

> If the generators were not ratebased and were not considered operating property, the Company would be able to sell the generators at a later date if it so chose. (Idaho Power Company's Response to the First Production Request of the Commission Staff, Case No. IPC-E-01-12, Response to Request No. 9.)

There could be other aspects of the plant that would allow for some cost recovery. Not allowing the plant in ratebase may be expensive for the Company; however, if it is allowed in ratebase it will be much more expensive for ratepayers.

Normalizing Peak

Q. Idaho Power's last rate case was ten years ago. How do the Company's loads compare to those that existed during the last rate case?

A. As surprising as it sounds energy consumption from native load is virtually the same as it was 10 years ago.

> The Company's 1993 annual normalized system load used in the IPC-E-94-5 case was 14.5 million megawatt-hours (MWh). The Company's 2003 annual normalized system load used in this case is 14.1 million MWh. The annual system load served today is approximately the same as it was ten years ago. (Idaho Power Direct Testimony of Greg Said, page 3, lines 8 to 13.)

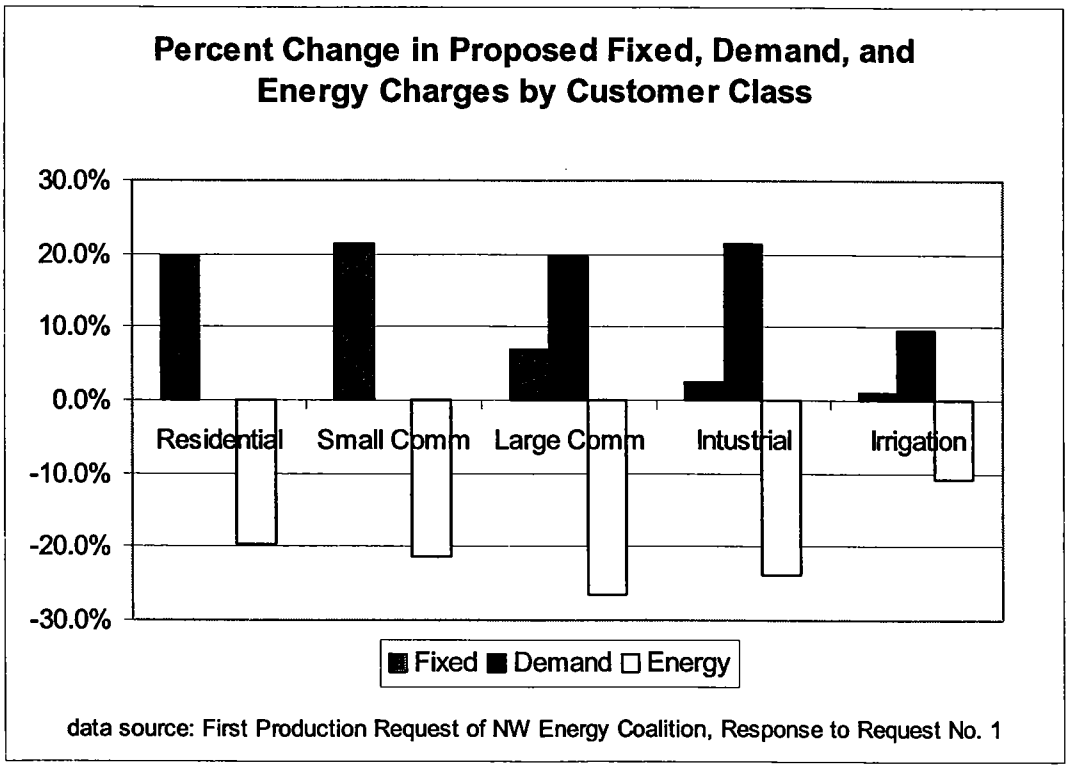
On a normalized basis consumption demand actually declined by 100,000 kWh annually. The major reason for this change has been the loss of the Astaris (FMC) load of 1.7 million MWh. In addition the Company has phased out FERC jurisdictional contract loads. While total load is flat compared to 10 years ago, there has been significant shifts in use from various customer classes. These shifts had led to a substantial change in the load profile of the Company.

> The FMC contract as well as the concluded FERC contracts that existed ten years ago provided the Company with relatively consistent monthly loads that were somewhat flat throughout the year. The FMC load had an interruptible component. Load growth within the various customer classes has tended to be much more seasonal and dependent upon weather. As a result of the loss of relatively flat loads and the addition of non-interruptible seasonal loads, the Company's Integrated Resource Plan now shows the need for summer peaking resources (June, July, and August) and winter peaking resources (November and December). (Idaho Power Direct Testimony of Greg Said, page 4,5, lines 13 to 23, line 1.)

Q. What has been the reaction of the Company to this dramatically different load profile?

A. One significant reaction has been the proposed shift in rate structure for all classes of customers in reducing kWh charges and increasing customer and demand rates. (Exhibit 203.)

Chart 4



Idaho Power states the primary approach to ratemaking is to reflect costs "as accurately as possible". (Idaho Power Direct Testimony of John R. Gale, page 11, lines 7,8.) Along with the proposed increases in fixed and demand changes, the Company has introduced both seasonal and diurnal rates.

Q. Are there other responses the Company has made to address the shift in system load profile?

A. Yes. Historically, the Company has maintained that its system was 'energy constrained' not 'capacity constrained'. This was due to the fact that it has a relatively high percent of its generation portfolio in hydro plants and its largest customer (Astaris/FMC) was largely interruptible. The Company could follow peak loads through the manipulation of its dams or through its ability to curtail its largest customer.

The loss of the Astaris/FMC interruptible load, and additional operating constraints on its hydro facilities (primarily for environmental concerns) have changed the Company's supply resources. In addition, a load profile that is more peak sensitive on the demand side has caused the Company to invest in peaking gas fired generation resources. This is a dramatic change. As discussed above the latest units -- both Danskin Station and the proposed Bennett Mountain plant -- are gas peaking units. Addressing peak has now become a priority for the Company.

Q. Because of these changes to Idaho Power's electric system can you think of other potential changes?

A. Due to these significant changes in the systems load profile, there should be a wholesale change in the way the Company looks at both its resources and customer demands. For example, demand side management (DSM) programs now has a different cost effective measuring stick. Rather than being focused on primarily on energy savings, they should also address the cost effectiveness of shaving peak. Another example may be the viability of a pump-storage generating units. Fifteen years ago the Company made a compelling case that this type of unit would not be cost effective. With the changes the system has undergone this may no longer be true.

Q. Because peak on the system has taken on such importance in the Company's resource planning and rate design, do you think there should be a difference in the

way Idaho Power looks at peak?

A. While the Company has a sophisticated weather normalization model for energy it does not weather normalize peak demand, either for the system or customer classes. In 1994 the Company did use weather adjusted peaks in their Marginal Cost Study.

> No, Idaho Power has never developed a method for weather normalizing peak loads by class for the purpose of a Cost of Service study. However, weather-adjusted system peaks were estimated for the purpose of the Marginal Cost Study published in January 1994. No studies had been done since then. (IPCo Response to 1st Production Request of ICIP, Response 49.)

At this time the Company states it is not planning to develop a method of weather adjusting peak.

> **Request No. 51:** Does the Company anticipate any future use of weather normalization of peak loads? If not please explain fully why not.
> **Response to Request No.51:** No. At this time the Company is not developing any methodology to weather normalize peak loads by class for the purpose of a Cost of Service Study.

Q. Why do you feel it is important for the Company to examine peak demands on a weather normalized basis?

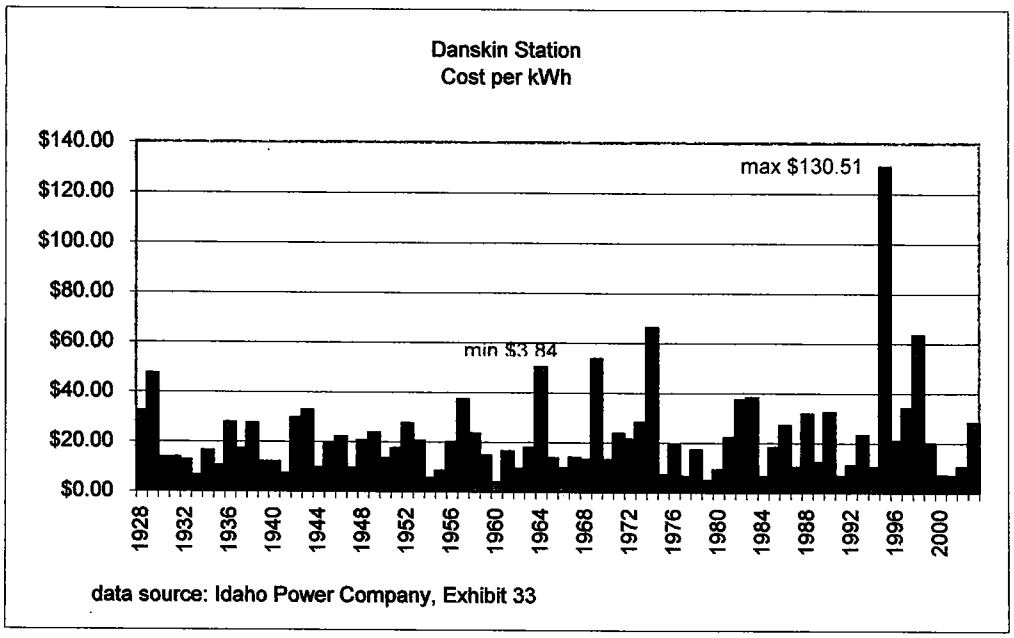
A. Peak demands are used by the Company in both its jurisdictional allocation studies and in customer class allocation factors in its Cost of Service Studies. To the extent that different customer classes (or jurisdictions) react differently to peak under different weather conditions the allocation factors that are developed would not be the same as those calculated from unadjusted data. This could mean a miss assignment of costs.

The Company uses weather normalized energy for resource planning and the calculation of revenue requirement. Now, with the substantial change in the Company's load profile,

ratepayers are being asked to pay increased fixed charges and fund peaking generation plant based on peak needs. The Company needs to investigate how peak loads react to weather conditions and what impact that it may have on inter-class allocations. The Commission should require the Company to undertake a peak weather normalized investigation.

Q. Does this conclude your testimony on February 20, 2003

A. Yes.


Danskin Station
Cost per kWh
$140.00
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$0.00
max $130.51
min $3.84
1928
1932
1936
1940
1944
1948
1952
1956
1960
1964
1968
1972
1976
1980
1984
1988
1992
1996
2000
data source: Idaho Power Company, Exhibit 33

(Idaho Power Company's Response to the First Production Request of the Commission Staff, Case No. IPC-E-01-12, Response to Request No. 8.)

Danskin Generation Summary

data source: Response to Request for Production, ICIP 1st, No. 53 &54

			Generation MWh			
		Total Operating Hours	Gross	Native Load	Off Systerm Sales	Price of Off System Sales $/MWh
2001	Sep	15.82	344	126	218	$21.77
	Oct	209.38	8,185	2,217	5,968	$26.34
	Nov	101.60	3,048	925	2,123	$22.16
	Dec	158.74	6,601	2,521	4,080	$24.48
		485.54	18,178	5,789	12,389	
	Percent			31.8%	68.2%	
	Average					**$23.69**
2002	Jan	42.57	1,902	299	1,603	$19.28
	Feb	50.33	2,411	1,127	1,284	$19.05
	Mar	136.85	6,164	1,970	4,194	$29.94
	Apr	28.26	1,048	123	925	$26.30
	May	41.52	1,439	1,169	270	$17.76
	Jun	148.14	5,789	5,600	189	$14.67
	Jul	481.00	19,097	19,097	-	
	Aug	29.29	1,136	1,136		
	Sep	24.40	917		917	$25.66
	Oct	76.76	3,260	166	3,094	$23.72
	Nov	0.00				
	Dec	25.55	1,500	1,280	220	$34.50
		1,084.67	44,663	31,967	12,696	
	Percent			71.6%	28.4%	
	Average					**$23.43**
2003	Jan	0.00				
	Feb	21.16	789		789	$49.79
	Mar	16.17	693	288	405	$61.42
	Apr	4.20	83		83	$34.39
	May	112.67	3,244	1,907	1,337	$32.25
	Jun	101.66	4,080	4,080		
	Jul	567.00	22,629	22,629		
	Aug	241.30	9,696	9,696		
	Sep	17.46	666	666		
	Oct	0.00				
	Nov	31.91	1,394	1,353	41	$36.81
	Dec	2.26	77	77		
		1,115.79	43,351	40,696	2,655	
	Percent			93.9%	6.1%	
	Average					**$42.93**
TOTALS		2,686.00	106,192	78,452	27,740	
Percent				73.9%	26.1%	
Average					**$30.02**	

IDAHO POWER COMPANY

Mtn. Home Generation Station

Months of Operation

2001

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-Peak	-	-	-	-	-	-	-	Y	Y	Y	Y	Y
Off-Peak	-	-	-	-	-	-	-	Y	Y	Y	Y	Y

2002

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-Peak	Y	Y	N	N	N	Y	Y	Y	Y	N	N	N
Off-Peak	N	N	N	N	N	Y	Y	Y	Y	N	N	N

2003

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-Peak	Y	N	N	N	N	N	Y	Y	Y	N	N	N
Off-Peak	N	N	N	N	N	N	Y	Y	N	N	N	N

2004

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-Peak	Y	N	N	N	N	N	N	Y	N	N	N	N
Off-Peak	N	N	N	N	N	N	N	N	N	N	N	N

2005

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-Peak	N	N	N	N	N	N	N	Y	N	N	N	N
Off-Peak	N	N	N	N	N	N	N	N	N	N	N	N

7/2/01

Exhibit 203

To Dave R. on 7/2 for Beginning

IDAHO POWER COMPANY

Mtn. Home Generation Station

Operating Plan

2001

Rank	Margin	Month	On/Off-P	Operating	Hours	Cumulative Hours	Net Income
1	$ 38	Aug-01	On-Peak	Y	424	424	$ 1,290,571
2	$ 35	Dec-01	On-Peak	Y	424	848	$ 1,188,684
3	$ 32	Oct-01	On-Peak	Y	425	1,273	$ 1,089,360
4	$ 30	Sep-01	On-Peak	Y	410	1,683	$ 985,230
5	$ 15	Dec-01	Off-Peak	Y	320	2,003	$ 384,480
6	$ 13	Aug-01	Off-Peak	Y	320	2,323	$ 333,216
7	$ 11	Nov-01	On-Peak	Y	410	2,733	$ 361,251
8	$ 10	Oct-01	Off-Peak	Y	320	3,053	$ 256,320
9	$ 6	Sep-01	Off-Peak	Y	310	3,363	$ 148,986
10	$ 3	Nov-01	Off-Peak	Y	310	3,673	$ 74,493
						Total 2001	$ 6,112,591

2002

Rank	Margin	Month	On/Off-P	Operating	Hours	Cumulative Hours	Net Income
1	$ 39	Aug-02	On-Peak	Y	424	424	$ 1,324,534
2	$ 26	Aug-02	Off-Peak	Y	320	744	$ 666,432
3	$ 20	Jul-02	On-Peak	Y	424	1,168	$ 679,248
4	$ 19	Jan-02	On-Peak	Y	424	1,592	$ 645,286
5	$ 16	Sep-02	Off-Peak	Y	310	1,902	$ 397,296
6	$ 15	Sep-02	On-Peak	Y	410	2,312	$ 492,615
7	$ 11	Feb-02	On-Peak	Y	383	2,695	$ 337,461
8	$ 7	Jul-02	Off-Peak	Y	320	3,015	$ 179,424
9	$ 2	Jun-02	On-Peak	Y	410	3,425	$ 65,682
9	$ 2	Jun-02	Off-Peak	Y	310	3,735	$ 49,662
11	$ (1)	Jan-02	Off-Peak	N	320	~~5,735~~ 4055	$ -
12	$ (2)	Dec-02	On-Peak	N	424	~~6,735~~ 4479	$ -
13	$ (3)	May-02	On-Peak	N	424	~~7,735~~ 4903	$ -
14	$ (4)	Oct-02	On-Peak	N	425	~~8,735~~ 5328	$ -
15	$ (6)	Nov-02	On-Peak	N	-	3,735	$ -
16	$ (7)	Dec-02	Off-Peak	N	-	3,735	$ -
17	$ (8)	May-02	Off-Peak	N	-	3,735	$ -
18	$ (9)	Feb-02	Off-Peak	N	-	3,735	$ -
19	$ (12)	Mar-02	On-Peak	N	-	3,735	$ -
20	$ (13)	Apr-02	On-Peak	N	-	3,735	$ -
21	$ (14)	Oct-02	Off-Peak	N	-	3,735	$ -
22	$ (16)	Nov-02	Off-Peak	N	-	3,735	$ -
23	$ (17)	Mar-02	Off-Peak	N	-	3,735	$ -
24	$ (18)	Apr-02	Off-Peak	N	-	3,735	$ -
						Total 2002	$ 4,837,640

2003

Rank	Margin	Month	On/Off-P	Operating	Hours	Cumulative Hours	Net Income
1	$ 23	Aug-03	On-Peak	Y	424	424	$ 781,135
2	$ 13	Aug-03	Off-Peak	Y	320	744	$ 333,216
3	$ 8	Jul-03	On-Peak	Y	424	1,168	$ 271,699
4	$ 6	Jan-03	On-Peak	Y	424	1,592	$ 203,774
5	$ 4	Sep-03	On-Peak	Y	410	2,002	$ 131,364
6	$ 1	Jul-03	Off-Peak	Y	320	2,322	$ 25,632
7	$ (1)	Feb-03	On-Peak	N	383	~~2,322~~ 2705	$ -
8	$ (3)	Sep-03	Off-Peak	N	310	~~2,322~~ 3015	$ -
9	$ (4)	Jan-03	Off-Peak	N	320	~~2,322~~ 3335	$ -
10	$ (6)	Jun-03	On-Peak	N	410	~~2,322~~ 3745	$ -
11	$ (9)	May-03	On-Peak	N	424	~~2,322~~ 4169	$ -
12	$ (10)	Feb-03	Off-Peak	N	289	~~2,322~~ 4458	$ -
13	$ (11)	Oct-03	On-Peak	N	425	~~2,322~~ 4883	$ -
13	$ (11)	Jun-03	Off-Peak	N	310	~~2,322~~ 5193	$ -
15	$ (12)	Dec-03	On-Peak	N	-	2,322	$ -
16	$ (14)	May-03	Off-Peak	N	-	2,322	$ -
17	$ (15)	Nov-03	On-Peak	N	-	2,322	$ -
18	$ (16)	Oct-03	Off-Peak	N	-	2,322	$ -
19	$ (18)	Apr-03	On-Peak	N	-	2,322	$ -
20	$ (19)	Mar-03	On-Peak	N	-	2,322	$ -
20	$ (19)	Dec-03	Off-Peak	N	-	2,322	$ -
22	$ (21)	Apr-03	Off-Peak	N	-	2,322	$ -
22	$ (21)	Nov-03	Off-Peak	N	-	2,322	$ -
24	$ (24)	Mar-03	Off-Peak	N	-	2,322	$ -
						Total 2003	$ 1,746,820

2004

Rank	Margin	Month	On/Off-P	Operating	Hours	Cumulative Hours	Net Income
1	$ 2	Aug-04	On-Peak	Y	424	424	$ 67,925
2	$ 1	Jan-04	On-Peak	Y	424	848	$ 33,962
3	$ (4)	Feb-04	On-Peak	N	397 ~~289~~	~~848~~ 1245	$ -
4	$ (7)	Aug-04	Off-Peak	N	320	~~848~~ 1565	$ -
5	$ (8)	Jan-04	Off-Peak	N	320	~~848~~ 1885	$ -
6	$ (9)	Jun-04	On-Peak	N	410	~~848~~ 2295	$ -
7	$ (12)	Jul-04	On-Peak	N	424	~~848~~ 2719	$ -
8	$ (13)	May-04	On-Peak	N	424	~~848~~ 3143	$ -
8	$ (13)	Feb-04	Off-Peak	N	299	~~848~~ 3442	$ -
10	$ (15)	Sep-04	On-Peak	N	410	~~848~~ 3852	$ -
11	$ (16)	Jun-04	Off-Peak	N	310	~~848~~ 4162	$ -
12	$ (18)	Dec-04	On-Peak	N	424	~~848~~ 4586	$ -
13	$ (20)	Jul-04	Off-Peak	N	320	~~848~~ 4906	$ -
13	$ (20)	Apr-04	On-Peak	N	410 ~~37~~	~~848~~ 5316	$ -
13	$ (20)	May-04	Off-Peak	N	-	848	$ -
16	$ (21)	Mar-04	On-Peak	N	-	848	$ -
17	$ (22)	Nov-04	On-Peak	N	-	848	$ -
18	$ (23)	Sep-04	Off-Peak	N	-	848	$ -
19	$ (26)	Apr-04	Off-Peak	N	-	848	$ -
19	$ (26)	Dec-04	Off-Peak	N	-	848	$ -
21	$ (28)	Mar-04	Off-Peak	N	-	848	$ -
22	$ (29)	Oct-04	On-Peak	N	-	848	$ -
22	$ (29)	Nov-04	Off-Peak	N	-	848	$ -
24	$ (36)	Oct-04	Off-Peak	N	-	848	$ -
						Total 2004	$ 101,887

2005

Rank	Margin	Month	On/Off-P	Operating	Hours	Cumulative Hours	Net Income
1	$ 2	Aug-05	On-Peak	Y	424	424	$ 67,925
2	-	Jan-05	On-Peak	Y	424	848	$ -
3	$ (7)	Feb-05	On-Peak	N	383	~~848~~ 1231	$ -
4	$ (10)	Aug-05	Off-Peak	N	320	~~848~~ 1551	$ -
5	$ (12)	Jul-05	On-Peak	N	424	~~848~~ 1975	$ -
5	$ (12)	Jan-05	Off-Peak	N	320	~~848~~ 2295	$ -
7	$ (15)	Sep-05	On-Peak	N	410	~~848~~ 2705	$ -
8	$ (18)	Feb-05	Off-Peak	N	289	~~848~~ 2994	$ -
8	$ (18)	Dec-05	On-Peak	N	424	~~848~~ 3418	$ -
10	$ (22)	Nov-05	On-Peak	N	410	~~848~~ 3828	$ -
11	$ (23)	Jul-05	Off-Peak	N	320	~~848~~ 4148	$ -
12	$ (25)	Mar-05	On-Peak	N	424	~~848~~ 4572	$ -
12	$ (25)	Jun-05	On-Peak	N	410	~~848~~ 4982	$ -
14	$ (26)	Sep-05	Off-Peak	N	310	~~848~~ 5292	$ -
15	$ (28)	Dec-05	Off-Peak	N	-	848	$ -
16	$ (29)	Oct-05	On-Peak	N	-	848	$ -
16	$ (29)	May-05	On-Peak	N	-	848	$ -
18	$ (32)	Nov-05	Off-Peak	N	-	848	$ -
19	$ (35)	Mar-05	Off-Peak	N	-	848	$ -
19	$ (35)	Jun-05	Off-Peak	N	-	848	$ -
21	$ (36)	Apr-05	On-Peak	N	-	848	$ -
22	$ (38)	Oct-05	Off-Peak	N	-	848	$ -
22	$ (38)	May-05	Off-Peak	N	-	848	$ -
24	$ (45)	Apr-05	Off-Peak	N	-	848	$ -
						Total 2005	$ 67,925

Total 01-05	$ 12,866,863

IDAHO POWER COMPANY

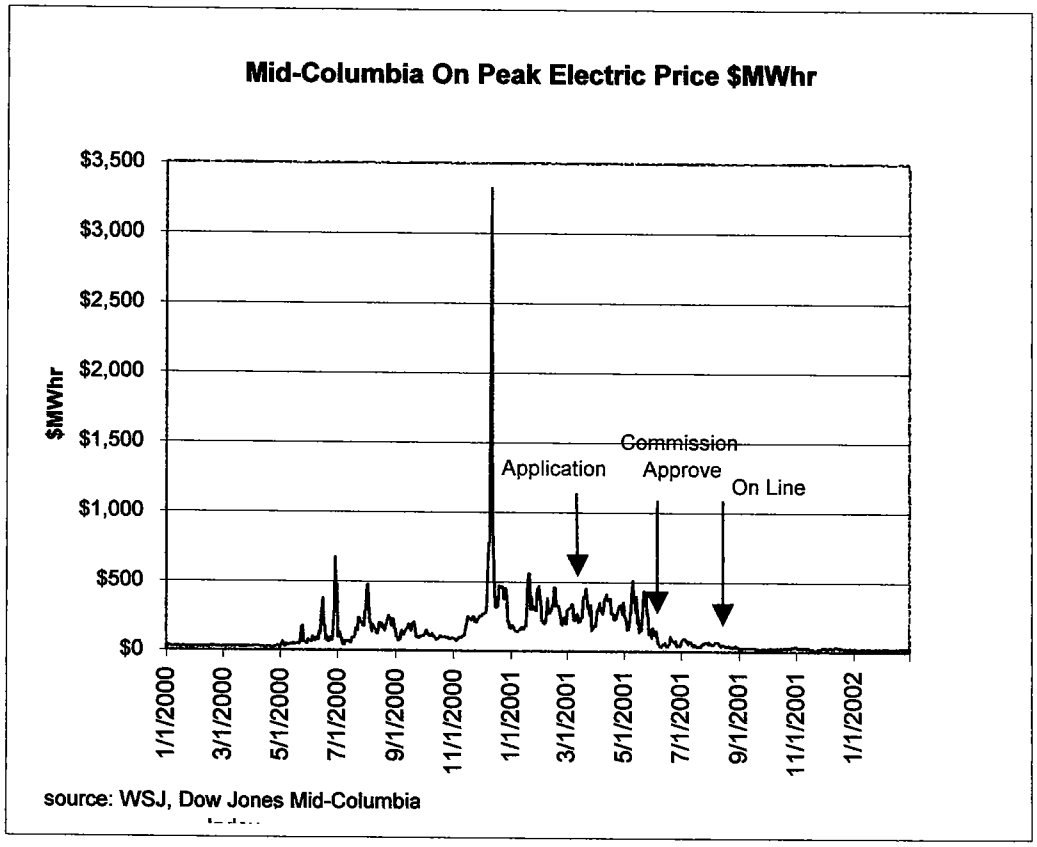
Mtn. Home Generation Station

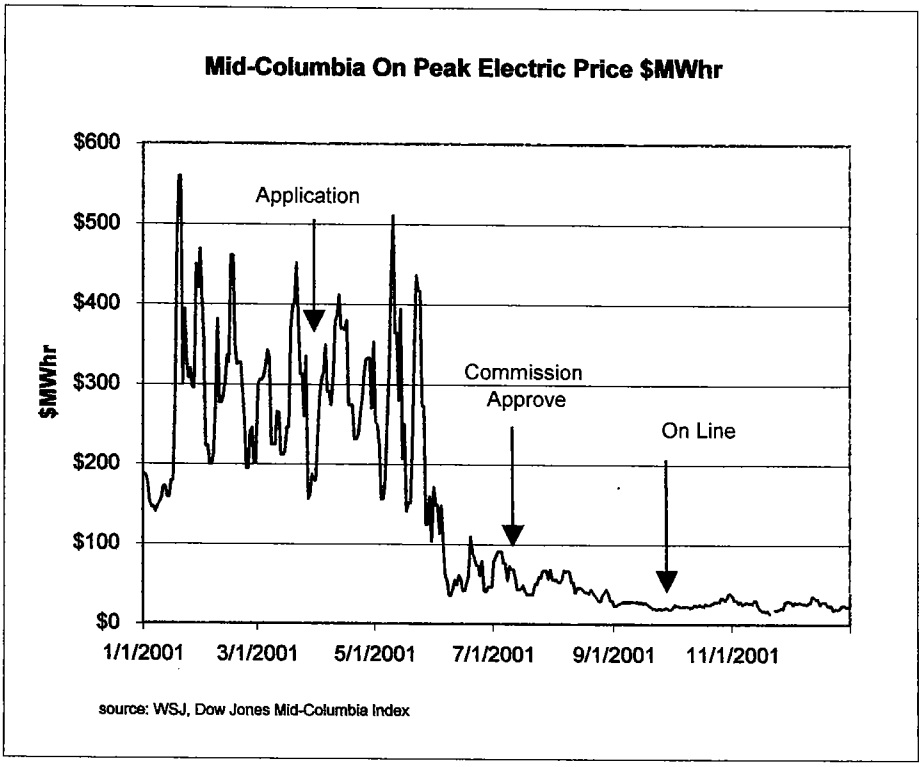
Operating Plan

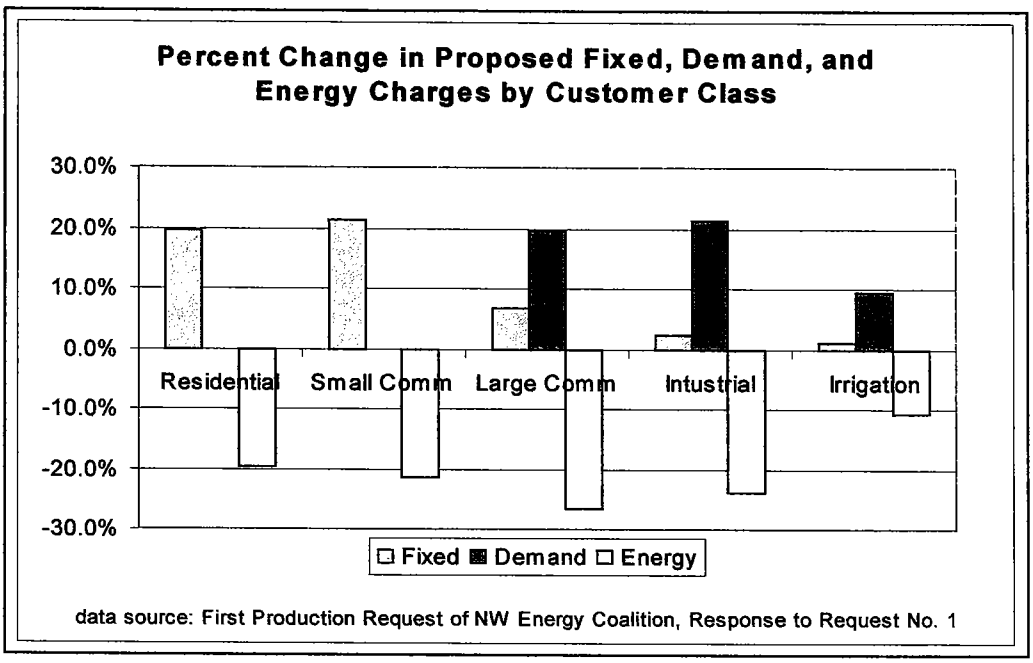
VARIABLES	
Heat Rate (Btu/KWh)	11,700
Total Capacity (Both CT's)	89
Equivalent Availability	90%
Other Operating $/MWh	$ 3.75
Max Annual Operating Hours	5,140

SENSITIVITY	
Gas ($/MMBtu)	$ -
Power ($/MWh)	$ -

Month	$/Mmbtu		$/MWh		$/MWh Based on Mid-C Price Forecast																	
	Cap/Com	Total C/C	Gas	Total Op	On-Peak	Total O-P	Margin	Rank	Op	Hours	Off-Peak	Total O-P	Margin	Rank	Op	Hours	Average	Total O-P	Margin	Rank	Op	Hours
Aug-01	$ 3.371	$ 3.371	$ 39	$ 43	$ 81	$ 81	$ 38	1	Y	424	$ 56	$ 56	$ 13	2	Y	320	$ 70	$ 70	$ 27	1	Y	744
Sep-01	$ 3.423	$ 3.423	$ 40	$ 44	$ 74	$ 74	$ 30	4	Y	410	$ 50	$ 50	$ 6	4	Y	310	$ 64	$ 64	$ 20	4	Y	720
Oct-01	$ 3.485	$ 3.485	$ 41	$ 45	$ 77	$ 77	$ 32	3	Y	425	$ 55	$ 55	$ 10	3	Y	320	$ 68	$ 68	$ 23	3	Y	745
Nov-01	$ 4.555	$ 4.555	$ 53	$ 57	$ 68	$ 68	$ 11	5	Y	410	$ 60	$ 60	$ 3	5	Y	310	$ 65	$ 65	$ 8	5	Y	720
Dec-01	$ 4.795	$ 4.795	$ 56	$ 60	$ 95	$ 95	$ 35	2	Y	424	$ 75	$ 75	$ 15	1	Y	320	$ 86	$ 86	$ 26	2	Y	744
2001 Total Operating Hours										2,093						1,580						3,673
Jan-02	$ 4.860	$ 4.860	$ 57	$ 61	$ 80	$ 80	$ 19	3	Y	424	$ 60	$ 60	$ (1)	5	N	0	$ 71	$ 71	$ 10	4	Y	744
Feb-02	$ 4.735	$ 4.735	$ 55	$ 59	$ 70	$ 70	$ 11	5	Y	383	$ 50	$ 50	$ (9)	8	N	0	$ 61	$ 61	$ 2	5	Y	672
Mar-02	$ 4.535	$ 4.535	$ 53	$ 57	$ 45	$ 45	$ (12)	11	N	0	$ 40	$ 40	$ (17)	11	N	0	$ 43	$ 43	$ (14)	11	N	0
Apr-02	$ 3.340	$ 3.340	$ 39	$ 43	$ 30	$ 30	$ (13)	12	N	0	$ 25	$ 25	$ (18)	12	N	0	$ 28	$ 28	$ (15)	12	N	0
May-02	$ 3.300	$ 3.300	$ 39	$ 43	$ 40	$ 40	$ (3)	8	N	0	$ 35	$ 35	$ (8)	7	N	0	$ 38	$ 38	$ (5)	8	N	0
Jun-02	$ 3.345	$ 3.345	$ 39	$ 43	$ 45	$ 45	$ 2	6	Y	410	$ 45	$ 45	$ 2	4	Y	310	$ 45	$ 45	$ 2	5	Y	720
Jul-02	$ 3.335	$ 3.335	$ 39	$ 43	$ 63	$ 63	$ 20	2	Y	424	$ 50	$ 50	$ 7	3	Y	320	$ 57	$ 57	$ 14	3	Y	744
Aug-02	$ 3.420	$ 3.420	$ 40	$ 44	$ 83	$ 83	$ 39	1	Y	424	$ 70	$ 70	$ 26	1	Y	320	$ 77	$ 77	$ 33	1	Y	744
Sep-02	$ 3.433	$ 3.433	$ 40	$ 44	$ 59	$ 59	$ 15	4	Y	410	$ 60	$ 60	$ 16	2	Y	310	$ 59	$ 59	$ 15	2	Y	720
Oct-02	$ 3.460	$ 3.460	$ 40	$ 44	$ 40	$ 40	$ (4)	9	N	0	$ 30	$ 30	$ (14)	9	N	0	$ 36	$ 36	$ (8)	9	N	0
Nov-02	$ 4.430	$ 4.430	$ 52	$ 56	$ 50	$ 50	$ (6)	10	N	0	$ 40	$ 40	$ (16)	10	N	0	$ 46	$ 46	$ (10)	10	N	0
Dec-02	$ 4.570	$ 4.570	$ 53	$ 57	$ 55	$ 55	$ (2)	7	N	0	$ 50	$ 50	$ (7)	6	N	0	$ 53	$ 53	$ (4)	7	N	0
2002 Total Operating Hours										2,475						1,260						4,344
Jan-03	$ 4.550	$ 4.550	$ 53	$ 57	$ 63	$ 63	$ 6	3	Y	424	$ 53	$ 53	$ (4)	4	N	0	$ 58	$ 58	$ 1	3	Y	744
Feb-03	$ 4.430	$ 4.430	$ 52	$ 56	$ 55	$ 55	$ (1)	5	N	0	$ 46	$ 46	$ (10)	5	N	0	$ 51	$ 51	$ (5)	5	N	0
Mar-03	$ 4.285	$ 4.285	$ 50	$ 54	$ 35	$ 35	$ (19)	12	N	0	$ 30	$ 30	$ (24)	12	N	0	$ 33	$ 33	$ (21)	12	N	0
Apr-03	$ 3.145	$ 3.145	$ 37	$ 41	$ 23	$ 23	$ (18)	11	N	0	$ 20	$ 20	$ (21)	10	N	0	$ 22	$ 22	$ (19)	11	N	0
May-03	$ 3.116	$ 3.116	$ 36	$ 40	$ 31	$ 31	$ (9)	7	N	0	$ 26	$ 26	$ (14)	7	N	0	$ 29	$ 29	$ (11)	7	N	0
Jun-03	$ 3.157	$ 3.157	$ 37	$ 41	$ 35	$ 35	$ (6)	6	N	0	$ 30	$ 30	$ (11)	6	N	0	$ 33	$ 33	$ (8)	6	N	0
Jul-03	$ 3.145	$ 3.145	$ 37	$ 41	$ 49	$ 49	$ 8	2	Y	424	$ 42	$ 42	$ 1	2	Y	320	$ 46	$ 46	$ 5	2	Y	744
Aug-03	$ 3.234	$ 3.234	$ 38	$ 42	$ 65	$ 65	$ 23	1	Y	424	$ 55	$ 55	$ 13	1	Y	320	$ 61	$ 61	$ 19	1	Y	744
Sep-03	$ 3.249	$ 3.249	$ 38	$ 42	$ 46	$ 46	$ 4	4	Y	410	$ 39	$ 39	$ (3)	3	N	0	$ 43	$ 43	$ 1	3	Y	720
Oct-03	$ 3.273	$ 3.273	$ 38	$ 42	$ 31	$ 31	$ (11)	8	N	0	$ 26	$ 26	$ (16)	8	N	0	$ 29	$ 29	$ (13)	8	N	0
Nov-03	$ 4.233	$ 4.233	$ 50	$ 54	$ 39	$ 39	$ (15)	10	N	0	$ 33	$ 33	$ (21)	10	N	0	$ 36	$ 36	$ (18)	10	N	0
Dec-03	$ 4.378	$ 4.378	$ 51	$ 55	$ 43	$ 43	$ (12)	9	N	0	$ 36	$ 36	$ (19)	9	N	0	$ 40	$ 40	$ (15)	9	N	0
2003 Total Operating Hours										1,682						640						2,952
Jan-04	$ 4.433	$ 4.433	$ 52	$ 56	$ 57	$ 57	$ 1	2	Y	424	$ 48	$ 48	$ (8)	2	N	0	$ 53	$ 53	$ (3)	2	N	0
Feb-04	$ 4.315	$ 4.315	$ 50	$ 54	$ 50	$ 50	$ (4)	3	N	0	$ 41	$ 41	$ (13)	3	N	0	$ 46	$ 46	$ (8)	3	N	0
Mar-04	$ 4.182	$ 4.182	$ 49	$ 53	$ 32	$ 32	$ (21)	10	N	0	$ 25	$ 25	$ (28)	10	N	0	$ 29	$ 29	$ (24)	10	N	0
Apr-04	$ 3.142	$ 3.142	$ 37	$ 41	$ 21	$ 21	$ (20)	9	N	0	$ 15	$ 15	$ (26)	8	N	0	$ 18	$ 18	$ (23)	9	N	0
May-04	$ 3.132	$ 3.132	$ 37	$ 41	$ 28	$ 28	$ (13)	6	N	0	$ 21	$ 21	$ (20)	5	N	0	$ 25	$ 25	$ (16)	5	N	0
Jun-04	$ 3.168	$ 3.168	$ 37	$ 41	$ 32	$ 32	$ (9)	4	N	0	$ 25	$ 25	$ (16)	4	N	0	$ 29	$ 29	$ (12)	4	N	0
Jul-04	$ 4.530	$ 4.530	$ 53	$ 57	$ 45	$ 45	$ (12)	5	N	0	$ 37	$ 37	$ (20)	5	N	0	$ 41	$ 41	$ (16)	5	N	0
Aug-04	$ 4.530	$ 4.530	$ 53	$ 57	$ 59	$ 59	$ 2	1	Y	424	$ 50	$ 50	$ (7)	1	N	0	$ 55	$ 55	$ (2)	1	N	0
Sep-04	$ 4.530	$ 4.530	$ 53	$ 57	$ 42	$ 42	$ (15)	7	N	0	$ 34	$ 34	$ (23)	7	N	0	$ 38	$ 38	$ (19)	7	N	0
Oct-04	$ 4.530	$ 4.530	$ 53	$ 57	$ 28	$ 28	$ (29)	12	N	0	$ 21	$ 21	$ (36)	12	N	0	$ 25	$ 25	$ (32)	12	N	0
Nov-04	$ 4.530	$ 4.530	$ 53	$ 57	$ 35	$ 35	$ (22)	11	N	0	$ 28	$ 28	$ (29)	11	N	0	$ 32	$ 32	$ (25)	11	N	0
Dec-04	$ 4.530	$ 4.530	$ 53	$ 57	$ 39	$ 39	$ (18)	8	N	0	$ 31	$ 31	$ (26)	8	N	0	$ 36	$ 36	$ (21)	8	N	0
2004 Total Operating Hours										848						0						0
Jan-05	$ 4.510	$ 4.510	$ 53	$ 57	$ 57	$ 57	$ -	2	Y	424	$ 45	$ 45	$ (12)	2	N	0	$ 52	$ 52	$ (5)	2	N	0
Feb-05	$ 4.510	$ 4.510	$ 53	$ 57	$ 50	$ 50	$ (7)	3	N	0	$ 39	$ 39	$ (18)	3	N	0	$ 45	$ 45	$ (12)	3	N	0
Mar-05	$ 4.510	$ 4.510	$ 53	$ 57	$ 32	$ 32	$ (25)	8	N	0	$ 22	$ 22	$ (35)	8	N	0	$ 28	$ 28	$ (29)	8	N	0
Apr-05	$ 4.510	$ 4.510	$ 53	$ 57	$ 21	$ 21	$ (36)	12	N	0	$ 12	$ 12	$ (45)	12	N	0	$ 17	$ 17	$ (40)	12	N	0
May-05	$ 4.510	$ 4.510	$ 53	$ 57	$ 28	$ 28	$ (29)	10	N	0	$ 19	$ 19	$ (38)	10	N	0	$ 24	$ 24	$ (33)	10	N	0
Jun-05	$ 4.510	$ 4.510	$ 53	$ 57	$ 32	$ 32	$ (25)	8	N	0	$ 22	$ 22	$ (35)	8	N	0	$ 28	$ 28	$ (29)	8	N	0
Jul-05	$ 4.510	$ 4.510	$ 53	$ 57	$ 45	$ 45	$ (12)	4	N	0	$ 34	$ 34	$ (23)	4	N	0	$ 40	$ 40	$ (17)	4	N	0
Aug-05	$ 4.510	$ 4.510	$ 53	$ 57	$ 59	$ 59	$ 2	1	Y	424	$ 47	$ 47	$ (10)	1	N	0	$ 54	$ 54	$ (3)	1	N	0
Sep-05	$ 4.510	$ 4.510	$ 53	$ 57	$ 42	$ 42	$ (15)	5	N	0	$ 31	$ 31	$ (26)	5	N	0	$ 37	$ 37	$ (20)	5	N	0
Oct-05	$ 4.510	$ 4.510	$ 53	$ 57	$ 28	$ 28	$ (29)	10	N	0	$ 19	$ 19	$ (38)	10	N	0	$ 24	$ 24	$ (33)	10	N	0
Nov-05	$ 4.510	$ 4.510	$ 53	$ 57	$ 35	$ 35	$ (22)	7	N	0	$ 25	$ 25	$ (32)	7	N	0	$ 31	$ 31	$ (26)	7	N	0
Dec-05	$ 4.510	$ 4.510	$ 53	$ 57	$ 39	$ 39	$ (18)	6	N	0	$ 29	$ 29	$ (28)	6	N	0	$ 35	$ 35	$ (22)	6	N	0
2005 Total Operating Hours										848						0						0


Mid-Columbia On Peak Electric Price $MWhr
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$0
$MWhr
Application
Commission
Approve
On Line
1/1/2000
3/1/2000
5/1/2000
7/1/2000
9/1/2000
11/1/2000
1/1/2001
3/1/2001
5/1/2001
7/1/2001
9/1/2001
11/1/2001
1/1/2002
source: WSJ, Dow Jones Mid-Columbia


Mid-Columbia On Peak Electric Price $MWhr
$600
$500
$400
$300
$200
$100
$0
$MWhr
Application
Commission
Approve
On Line
1/1/2001
3/1/2001
5/1/2001
7/1/2001
9/1/2001
11/1/2001
source: WSJ, Dow Jones Mid-Columbia Index


Percent Change in Proposed Fixed, Demand, and Energy Charges by Customer Class
30.0%
20.0%
10.0%
0.0%
-10.0%
-20.0%
-30.0%
Residential
Small Comm
Large Comm
Intustrial
Irrigation
Fixed
Demand
Energy
data source: First Production Request of NW Energy Coalition, Response to Request No. 1

Don C. Reading

Present position Consulting Economist with Ben Johnson Associates, Inc.:

Education
B.S., Economics - Utah State University
M.S., Economics - University of Oregon
Ph.D., Economics - Utah State University

Professional and business history

Idaho Public Utilities Commission:
1981-86 Economist/Director of Policy and Administration

Teaching:
1980-81 Associate Professor, University of Hawaii-Hilo
1970-80 Associate and Assistant Professor, Idaho State University
1968-70 Assistant Professor, Middle Tennessee State University

Dr. Reading provides expert testimony concerning economic and regulatory issues. He has testified on more than 25 occasions before utility regulatory commissions in Alaska, California, Colorado, the District of Columbia, Idaho, Nevada, Texas, Utah, and Washington.

His areas of expertise include demand forecasting, long-range planning, price elasticity, marginal pricing, production-simulation modeling, and econometric modeling. He has also provided expert testimony in cases concerning loss of income resulting from wrongful death, injury, or employment discrimination.

Dr. Reading has more than 30 years experience in the field of economics. He has participated in the development of indices reflecting economic trends, GNP growth rates, foreign exchange markets, the money supply, stockmarket levels, and inflation. He has analyzed such public policy issues as the minimum wage, federal spending and taxation, and import/export balances. Dr. Reading is one of four economists providing yearly forecasts of statewide personal income to the State of Idaho for purposes of establishing state personal income tax rates.

Dr. Reading's areas of expertise in the field of energy include demand forecasting, long-range planning, price elasticity, marginal and average cost pricing, production-simulation modeling, and econometric modeling. Among his recent cases was an electric rate design analysis for the Industrial Customers of Idaho Power.

While at Idaho State University, Dr. Reading performed demographic

studies using a cohort/survival model and several economic impact studies using input/output analysis. He has also provided expert testimony in cases concerning loss of income resulting from wrongful death, injury, or employment discrimination.

Among Dr. Reading's current projects are a FERC hydropower relicensing study (for the Skokomish Indian Tribe) and an analysis of Northern States Power's North Dakota rate design proposals affecting large industrial customers (for J.R. Simplot Company). Dr. Reading has also recently completed an analysis for the Idaho Governor's Office of the impact on the Northwest Power Grid of various plans to increase salmon runs in the Columbia River Basin.

Publications

The Economic Impact of Steelhead Fishing and the Return of Salmon Fishing in Idaho, Idaho Fish and Wildlife Foundation, September, 1997.

Cost Savings from Nuclear Regulatory Reform, Southern Economic Journal, March, 1997, with R. Canterbery and B. Johnson.

A Visitor Analysis for a Birds of Prey Public Attraction, Peregrine Fund, Inc., November, 1988.

Investigation of a Capitalization Rate for Idaho Hydroelectric Projects, Idaho State Tax Commission, June, 1988.

"Post-PURPA Views," In Proceedings of the NARUC Biennial Regulatory Conference, 1983.

An Input-Output Analysis of the Impact from Proposed Mining in the Challis Area (with R. Davies). Public Policy Research Center, Idaho State University, February 1980.

Phosphate and Southeast: A Socio Economic Analysis (with J. Eyre, et al). Government Research Institute of Idaho State University and the Southeast Idaho Council of Governments, August 1975.

Estimating General Fund Revenues of the State of Idaho (with S. Ghazanfar and D. Holley). Center for Business and Economic Research, Boise State University, June 1975.

"A Note on the Distribution of Federal Expenditures: An Interstate Comparison, 1933-1939 and 1961-1965." In The American Economist, Vol. XVIII, No. 2 (Fall 1974), pp. 125-128.

New Deal Activity and the States, 1933-1939." In Journal of Economic History, Vol. XXXIII (December 1973), pp. 792-810.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 19th day of February, 2004, I caused a true and correct copy of the foregoing **DIRECT TESTIMONY OF DR. DON READING** to be served by the method indicated below, and addressed to the following:

Jean Jewell Idaho Public Utilities Commission 472 West Washington Street Post Office Box 83720 Boise, Idaho 83720-0074	( ) U.S. Mail, Postage Prepaid (X) Hand Delivered ( ) Overnight Mail ( ) Facsimile ( ) Electronic Mail
Barton L. Kline Monica B. Moen Idaho Power Company PO Box 70 Boise, ID 83707-0070 bkline@idahopower.com mmoen@idahopower.com	( ) U.S. Mail, Postage Prepaid (X) Hand Delivered ( ) Overnight Mail ( ) Facsimile ( ) Electronic Mail
Lisa Nordstrom Weldon Stutzman Deputy Attorney Generals Idaho Public Utilities Commission PO Box 83720 Boise, ID 83720-0074 lnordst@puc.state.id.us	( ) U.S. Mail, Postage Prepaid (X) Hand Delivered ( ) Overnight Mail ( ) Facsimile ( ) Electronic Mail
John R. Gale VP – Regulatory Affairs Idaho Power Company Post Office Box 70 Boise, Idaho 83707-0070 rgale@idahopower.com	( ) U.S. Mail, Postage Prepaid (X) Hand Delivered ( ) Overnight Mail ( ) Facsimile ( ) Electronic Mail
Randall C. Budge Eric L. Olsen Racine, Olson, Nye, Budge, Bailey, Chartered PO Box 1391 Pocatello, ID 83204-1391 rcb@racinelaw.net elo@racinelaw.net	( ) U.S. Mail, Postage Prepaid ( ) Hand Delivered (X) Overnight Mail ( ) Facsimile ( ) Electronic Mail

Anthony Yankel 29814 Lake Road Bay Village, OH 44140 yankel@attbi.com	( ) U.S. Mail, Postage Prepaid ( ) Hand Delivered (X) Overnight Mail ( ) Facsimile ( ) Electronic Mail
Lawrence A. Gollomp Assistant General Counsel United States Department of Energy 1000 Independence Ave., SW Washington, DC 20585 lawrence.gollomp@hq.doe.gov	( ) U.S. Mail, Postage Prepaid ( ) Hand Delivered (X) Overnight Mail ( ) Facsimile ( ) Electronic Mail
Dennis Goins Potomac Management Group 5801 Westchester Street Alexandria, VA 22310-1149 dgoinspmg@aol.com	( ) U.S. Mail, Postage Prepaid ( ) Hand Delivered (X) Overnight Mail ( ) Facsimile ( ) Electronic Mail
Dean J. Miller McDevitt & Miller LLP PO Box 2564 Boise, ID 83701 joe@mcdevitt-miller.com	( ) U.S. Mail, Postage Prepaid (X) Hand Delivered ( ) Overnight Mail ( ) Facsimile ( ) Electronic Mail
Jeremiah J. Healy United Water Idaho, Inc. PO Box 190420 Boise, Idaho 83719-0420 jerry.healy@unitedwater.com	( ) U.S. Mail, Postage Prepaid (X) Hand Delivered ( ) Overnight Mail ( ) Facsimile ( ) Electronic Mail
William M. Eddie Advocated for the West PO Box 1612 Boise, ID 83701 billeddie@rmci.net	(X) U.S. Mail, Postage Prepaid ( ) Hand Delivered ( ) Overnight Mail ( ) Facsimile ( ) Electronic Mail

Nancy Hirsch
NW Energy Coalition
219 First Ave. South
Suite 100
Seattle, WA 98104
nancy@nwenergy.org

( ) U.S. Mail, Postage Prepaid
( ) Hand Delivered
(X) Overnight Mail
( ) Facsimile
( ) Electronic Mail

Conley Ward
Givens Pursley LLP
601 W. Bannock Street
PO Box 2720
Boise, Idaho 83701-2720
cew@givenspursley.com

( ) U.S. Mail, Postage Prepaid
(X) Hand Delivered
( ) Overnight Mail
( ) Facsimile
( ) Electronic Mail

Dennis E. Peseau, Ph.D.
Utility Resources, Inc.
1500 Liberty Street SE, Suite 250
Salem, OR 97302
dennytemp@yahoo.com

( ) U.S. Mail, Postage Prepaid
( ) Hand Delivered
(X) Overnight Mail
( ) Facsimile
( ) Electronic Mail

Brad M. Purdy
Attorney at Law
2019 N. 17th Street
Boise, Idaho 83702
bmpurdy@hotmail.com

( ) U.S. Mail, Postage Prepaid
(X) Hand Delivered
( ) Overnight Mail
( ) Facsimile
( ) Electronic Mail

Michael Karp
147 Appaloosa Lane
Bellingham, WA 98229
Michael@awish.net

( ) U.S. Mail, Postage Prepaid
( ) Hand Delivered
(X) Overnight Mail
( ) Facsimile
( ) Electronic Mail

Don Reading
Ben Johnson Associates
6070 Hill Road
Boise, Idaho 83703
dreading@mindspring.com

(X) U.S. Mail, Postage Prepaid
( ) Hand Delivered
( ) Overnight Mail
( ) Facsimile
( ) Electronic Mail

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
Boehm, Kurtz & Lowry
36 E. Seventh Street, Suite 2110
Cincinnati, OH 45202
mkurtzlaw@aol.com

( ) U.S. Mail, Postage Prepaid
( ) Hand Delivered
(X) Overnight Mail
( ) Facsimile
( ) Electronic Mail

Signed Nina M. Curtis
Nina M. Curtis