McDowell
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Lisa Rackner
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March 9, 2012

**VIA ELECTRONIC FILING AND U.S. MAIL**

PUC Filing Center
Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
PO Box 2148
Salem, OR 97308-2148

**Re: Advice No. 12-06; Docket No. UE _____**
In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service to its Customers in the State of Oregon Due to the Inclusion of the Langley Gulch Power Plant Investment in Rate Base.

Pursuant to ORS 757.210, enclosed for filing by Idaho Power Company are an original and seven (7) copies of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service to its Customers in the State of Oregon Due to the Inclusion of the Langley Gulch Power Plant Investment in Rate Base, including the following proposed tariff pages associated with the Company's Tariff P.U.C. ORE No. E-27 applicable to electric service in the State of Oregon, together with the Executive Summary, supporting direct testimony and exhibits. The tariffs reflect an effective date of July 1, 2012.

| | | |
|---|---|---|
| Seventh Revised Sheet No. 1-2 | Cancelling | Sixth Revised Sheet No. 1-2 |
| Fifth Revised Sheet No. 7-2 | Cancelling | Fourth Revised Sheet No. 7-2 |
| Sixth Revised Sheet No. 9-3 | Cancelling | Fifth Revised Sheet No. 9-3 |
| Fifth Revised Sheet No. 9-4 | Cancelling | Fourth Revised Sheet No. 9-4 |
| Fourth Revised Sheet No. 15-2 | Cancelling | Third Revised Sheet No. 15-2 |
| Sixth Revised Sheet No. 19-3 | Cancelling | Fifth Revised Sheet No. 19-3 |
| Fifth Revised Sheet No. 19-4 | Cancelling | Fourth Revised Sheet No. 19-4 |
| Fifth Revised Sheet No. 19-5 | Cancelling | Fourth Revised Sheet No. 19-5 |
| Sixth Revised Sheet No. 24-3 | Cancelling | Fifth Revised Sheet No. 24-3 |
| Seventh Revised Sheet No. 40-2 | Cancelling | Sixth Revised Sheet No. 40-2 |
| Sixth Revised Sheet No. 41-2 | Cancelling | Fifth Revised Sheet No. 41-2 |
| Sixth Revised Sheet No. 41-3 | Cancelling | Fifth Revised Sheet No. 41-3 |
| Fifth Revised Sheet No. 41-4 | Cancelling | Fourth Revised Sheet No. 41-4 |
| Sixth Revised Sheet No. 42-1 | Cancelling | Fifth Revised Sheet No. 42-1 |

It is respectfully requested that all data requests regarding this matter be addressed to:

Lisa D. Nordstrom
Idaho Power Company
PO Box 70
Boise, ID 83707-0070
Email: lnordstrom@idahopower.com

Lisa Rackner
McDowell Rackner & Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205
Email: dockets@mcd-law.com

Christa Bearry
Idaho Power Company
PO Box 70
Boise, ID 83707-0070
Email: cbearry@idahopower.com

Idaho Power waives paper service in this docket. Please address all communications related to this filing to:

Lisa D. Nordstrom
Idaho Power Company
PO Box 70
Boise, ID 83707-0070
Email: lnordstrom@idahopower.com

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Christa Bearry
Idaho Power Company
PO Box 70
Boise, ID 83707-0070
Email: cbearry@idahopower.com

Please direct informal correspondence and questions regarding this filing to Lisa Rackner at (503) 595-3925.

Very truly yours,

Lisa Rackner

Enclosure

## CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket No. UE ____ on the parties to Docket No. UE 233 (Idaho Power's 2011 General Rate Case) on the following named person(s) on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

| | |
|---|---|
| Gordon Feighner<br>Citizens' Utility Board of Oregon<br>gordon@oregoncub.org | Robert Jenks<br>Citizens' Utility Board of Oregon<br>bob@oregoncub.org |
| Catriona McCracken<br>Citizens' Utility Board of Oregon<br>catriona@oregoncub.org | Stephanie Andrus<br>Assistant Attorney General<br>stephanie.andrus@state.or.us |
| Don Reading<br>dreading@mindspring.com | Judy Johnson<br>Public Utility Commission of Oregon<br>judy.johnson@state.or.us |
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| Peter J. Richardson<br>Richardson & O'Leary<br>peter@richardsonandoleary.com | Joshua D. Johnson<br>Attorney at Law<br>jdj@racinelaw.net |
| Eric L. Olsen<br>Attorney at Law<br>elo@racinelaw.com | Anthony J. Yankel<br>Utility Net.Inc.<br>tony@yankel.net |
| Randy Dahlgren<br>Portland General Electric<br>pge.opuc.filings@pgn.com | Douglas C. Tingey<br>Portland General Electric<br>doug.tingey@pgn.com |
| Erik Colville<br>Public Utility Commission of Oregon<br>erik.colville@state.or.us | |

DATED: March 9, 2012

Candace Duncan

Candace Duncan
Legal Assistant



McDowell Rackner & Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

**BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON**

**DOCKET UE_____**

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ITS CUSTOMERS IN THE STATE OF OREGON DUE TO THE INCLUSION OF THE LANGLEY GULCH POWER PLANT INVESTMENT IN RATE BASE. | **IDAHO POWER COMPANY'S EXECUTIVE SUMMARY** |

## I. INTRODUCTION

Idaho Power Company ("Idaho Power" or "Company") is filing a general rate increase with the Public Utility Commission of Oregon ("Commission"), pursuant to ORS 757.205, 757.215 and 757.220, to revise its schedules of rates and charges for electric service in Oregon to become effective with service provided on and after July 1, 2012. With this filing, the Company requests an increase to customer rates that will increase the Company's annual Oregon jurisdictional revenues by $3 million, which is 7.32 percent greater than the revenues that could be generated under current rates. The revised rates produce revenues necessary to sustain the provision of stable, reliable, and low-cost electric service to customers in Oregon, while preserving the Company's ability to attract capital for future investments in system infrastructure. The Company files this executive summary in accordance with OAR 860-022-0019.

## II. BACKGROUND

Idaho Power is an Idaho corporation whose principal place of business is 1221 West Idaho Street, Boise, Idaho 83702. Idaho Power is an electric company and a public utility providing electric service in Oregon within the meaning of ORS 757.005. The Company is subject to the jurisdiction of this Commission, the Idaho Public Utilities Commission, and the

Federal Energy Regulatory Commission. The Company provides electric service to approximately 18,453 customers in Oregon and approximately 492,073 total customers in Idaho and Oregon. In conducting its utility business, Idaho Power operates an interconnected and integrated system.

Communications regarding this filing should be addressed to:

Lisa D. Nordstrom
Idaho Power Company
PO Box 70
Boise, ID 83707-0070
Telephone: 208-388-5825
Facsimile: 208-388-6936
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Communications regarding discovery matters, including data requests issued to the Company, should be addressed to:

Lisa D. Nordstrom
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## III. CASE SUMMARY

### A. Acquisition of Langley

The proposed increase in rates and charges is the result of the inclusion of the Langley Gulch power plant ("Langley") in the Company's revenue requirement. Langley is a 300 megawatt natural gas-fired combined cycle combustion turbine located approximately five miles south of New Plymouth, Idaho. The Company acquired Langley to meet the need for 250 MW to 600 MW of dispatchable, physically delivered firm or unit contingent energy deliverable in 2012 ("2012 Baseload Resource") that was identified in the Company's Resource Plans dating back to 2004.

The Company issued a request for proposal ("RFP") for the 2012 Baseload Resource in April of 2008. The RFP evaluation process, which is discussed in the testimony of Lisa A. Grow, concluded that the Langley Project provides the greatest value for customers. Although time pressures required the Company to use a more streamlined RFP than the Commission's Competitive Bidding Guidelines ("Guidelines"), the Company's RFP process was robust and fair, as demonstrated by the fact that the 20-year NPV of the revenue requirements for the Langley Gulch Project were $108 million less than the next closest combined cycle project on the short-list. The testimony of Gregory W. Said explains the time pressures that limited the Company's ability to meet the Guidelines.

The Company's RFP process and acquisition of Langley were overseen by the Idaho Public Utilities Commission ("IPUC"). The Company was granted a Certificate of Public Convenience and Necessity ("CPCN") to build Langley by the Idaho Public Utilities Commission on September 1, 2009, in Case No. IPE-E-09-03 on the basis that the future public convenience and necessity requires the construction of Langley, IPUC Order No. 30892.

As described in the Direct Testimony of Gregory W. Said, the investment in Langley for purposes of determining the Company's additional revenue requirement is $390,942,172.



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Portland, OR 97205

Using the Company's overall rate of return of 7.757 percent, as authorized by the Commission in Docket UE 233, and including depreciation and the applicable tax rates, an additional revenue requirement of $3,049,660 is specified for the Oregon jurisdiction.

The Company proposes to spread the increase to each individual customer class based on the rate spread agreed to by the parties in UE 233 and approved by the Commission in Order No. 12-055.

**B. Request for Authority to Include Langley in Rates**

The Company requests that the Commission approve the tariff sheets allowing for recovery of the revenue requirement associated with Langley beginning on July 1, 2012, the date that the Company expects the project will be used and useful. Although the Commission generally allows resources into rates in general rate cases upon a review of all costs and revenues, allowing Langley into rates in this proceeding is appropriate. The Commission recently conducted a comprehensive evaluation of the Company's costs and revenues in its general rate case Docket UE 233, culminating in Order No. 12-055 issued on February 23, 2012, approximately two weeks ago. Rates in that case went into effect approximately a week ago, on March 1, 2012. Because the suspension period in Docket UE 233 ended before Langley was expected to come on line, on July 1, 2012, the Company did not include the project in rates in that case. Given that the Commission just completed an evaluation of the Company's costs and revenues, administrative efficiency militates in favor of evaluating the inclusion of Langley in rates in this case rather than in another general rate case. Such an approach is consistent with Commission policy, as described in the testimony of Gregory W. Said. This approach will also coincide with the reduction of power supply expenses (a $2.6 million benefit to customers) due to Langley's inclusion as a resource in the Annual Power Cost Update as filed in Docket UE 242.

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## IV. TESTIMONY SUMMARY

The Company's direct case consists of the testimony and exhibits of Gregory W. Said and Lisa A. Grow. Mr. Said describes the integrated resource plan process that led to the acquisition of Langley; explains the streamlined competitive bidding process to acquire Langley; describes the regulatory oversight of the Langley acquisition by the Idaho Public Utilities Commission; presents the Company's request for approval in this case; and presents the revenue requirement impact of this investment and the Company's proposed rate spread. Ms. Grow discusses the RFP process used to select the power plant now known as Langley Gulch; quantifies the Company's investment in Langley Gulch; and discusses the expected completion and in-service date for the Langley Gulch Power Plant.

## V. CONCLUSION

The Company requests that the Commission issue an order approving of the proposed rate changes and approving the proposed tariffs effective July 1, 2012, when the Langley Gulch Power Plant is expected to be in commercial operation.

DATED: March 9, 2012.

**MCDOWELL RACKNER & GIBSON PC**

Lisa F. Rackner
Amie Jamieson

**IDAHO POWER COMPANY**

Lisa Nordstrom
Idaho Power Company
P.O. Box 70
1221 W. Idaho Street
Boise, Idaho 83707-0070
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Attorneys for Idaho Power Company

**Exhibit A**
**Summary of Requested Electric General Rate Increase**
Oregon Jurisdiction
Filed March 9, 2012

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| | |
|---|---|
| Total Revenues Collected Under Proposed Rates: | $ 44,734,107 |
| Revenue Change Requested: | $ 3,049,660 |
| Revenues Net of any Credits from Federal Agencies: | $ 3,049,660 |
| Percentage Change in Revenues Requested: | 7.32% |
| Percentage Change in Revenues Net of any Credits from Federal Agencies: | 7.32% |
| Test Period: | Calendar Year 2012 |
| Requested Rate of Return on Capital: | 7.757% |
| Requested Rate of Return on Equity: | 9.9% |
| Proposed Rate Base: | $ 123,111,407 |
| Results of Operation[1] | |
| Before Proposed Rate Change | |
| Utility Operating Income: | $ 8,363,468 |
| Average Rate Base: | $ 107,818,335 |
| Rate of Return on Capital: | 7.757% |
| Rate of Return on Equity: | 9.9% |
| After Proposed Rate Change | |
| Utility Operating Income: | $ 9,549,752 |
| Average Rate Base: | $ 123,111,407 |
| Rate of Return on Capital: | 7.757% |
| Rate of Return on Equity: | 9.9% |
| Effect of Rate Change on Each Customer Class | |
| Residential Service: | 6.18% |
| Small General Service: | 5.14% |
| Large General Service, Secondary Voltage: | 7.31% |
| Large General Service, Primary Voltage: | 8.05% |
| Large General Service, Transmission Voltage: | 7.61% |
| Area Lighting Service: | 1.51% |
| Large Power Service, Primary Voltage: | 8.62% |
| Large Power Service, Transmission Voltage: | 10.58% |
| Irrigation Service: | 7.49% |
| Unmetered General Service: | 5.52% |
| Municipal Street Lighting Service: | 2.14% |
| Traffic Control Lighting Service: | 5.40% |

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[1] Based upon the Results of Operation as approved in the Company's 2011 general rate case filing.



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419 SW Eleventh Avenue, Suite 400
Portland, OR 97205

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

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Advice No. 12-06
Proposed Tariffs

March 9, 2012

SCHEDULE 1
RESIDENTIAL SERVICE
(Continued)

RESIDENTIAL SPACE HEATING (Continued)

Individual resistance-type units for space heating larger than 1,650 watts shall be designed to operate at 240 or 208 volts, and no single unit shall be larger than 6 kW. Heating units of two kW or larger shall be controlled by approved thermostatic devices. When a group of heating units, with a total capacity of more than 6 kW, is to be actuated by a single thermostat, the controlling switch shall be so designed that not more than 6 kW can be switched on or off at any one time. Supplemental resistance-type heaters, that may be used with a heat exchanger, shall comply with the specifications listed above for such units.

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

| | | |
|---|---|---|
| Service Charge, per month | $ 8.00 | |
| Energy Charge, per kWh | | |
| 0-1000 kWh | 7.4879¢ | (I) |
| Over 1000 kWh | 8.9356¢ | (I) |
| Power Supply Adjustment, per kWh | 0.3507¢ | |

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 7
SMALL GENERAL SERVICE
(Continued)

MONTHLY CHARGE (Continued)

| | Summer | Non-Summer | |
|---|---|---|---|
| Energy Charge, per kWh | | | |
| 0-500 kWh | 7.0292¢ | 7.0292¢ | (I) |
| Over 500 kWh | 9.5849¢ | 7.8242¢ | (I) |
| Power Supply Adjustment, per kWh | 0.3507¢ | 0.3507¢ | |

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

| SECONDARY SERVICE | Summer | Non-Summer | |
|---|---|---|---|
| Service Charge, per month | | | |
| Single Phase Service | $ 10.25 | $ 10.25 | |
| Three Phase Service | $ 17.35 | $ 17.35 | |
| Basic Charge, per kW of Basic Load Capacity | $ 0.75 | $ 0.75 | (I) |
| Demand Charge, per kW of Billing Demand | $ 6.00 | $ 4.50 | (I) |
| Energy Charge, per kWh | 5.0506¢ | 4.6355¢ | (I) |
| Power Supply Adjustment, per kWh | 0.3507¢ | 0.3507¢ | |

Facilities Charge
None

| PRIMARY SERVICE | Summer | Non-Summer | |
|---|---|---|---|
| Service Charge, per month | $202.00 | $202.00 | |
| Basic Charge, per kW of Basic Load Capacity | $ 1.23 | $ 1.23 | (I) |
| Demand Charge, per kW of Billing Demand | $ 5.93 | $ 4.84 | (I) |
| On-Peak Demand Charge, per kW of On-Peak Billing Demand | $ 0.87 | n/a | (I) |
| Energy Charge, per kWh | | | |
| On-Peak | 4.8864¢ | n/a | (I) |
| Mid-Peak | 4.5662¢ | 4.1263¢ | (I) |
| Off-Peak | 4.3605¢ | 3.9946¢ | (I) |
| Power Supply Adjustment, per kWh | 0.3507¢ | 0.3507¢ | |

Facilities Charge

The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.41 percent.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

MONTHLY CHARGE (Continued)

| TRANSMISSION SERVICE | Summer | Non-Summer | |
|---|---|---|---|
| Service Charge, per month | $200.00 | $200.00 | |
| Basic Charge, per kW of Basic Load Capacity | $ 0.32 | $ 0.32 | (I) |
| Demand Charge, per kW of Billing Demand | $ 3.87 | $ 4.14 | (I) |
| On-Peak Demand Charge, per kW of On-Peak Billing Demand | $ 0.74 | n/a | (I) |
| Energy Charge, per kWh | | | |
| On-Peak | 4.5436¢ | n/a | (I) |
| Mid-Peak | 4.2535¢ | 3.8386¢ | (I) |
| Off-Peak | 4.0638¢ | 3.7175¢ | (I) |
| Power Supply Adjustment, per kWh | 0.3507¢ | 0.3507¢ | |

Facilities Charge

The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.41 percent.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 15
DUSK TO DAWN CUSTOMER LIGHTING
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the per Unit Charge and the Power Supply Adjustment at the following charges, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), and Schedule 95 (Adjustment for Municipal Exactions).

1. Monthly Per Unit Charge on existing facilities:

AREA LIGHTING

| High Pressure Sodium Vapor | Average Lumens | Monthly Base Rate | Power Supply Adjustment | |
|---|---|---|---|---|
| 100 Watt | 8,550 | $ 10.53 | $ 0.14 | (I) |
| 200 Watt | 19,800 | $ 12.59 | $ 0.26 | (I) |
| 400 Watt | 45,000 | $ 17.22 | $ 0.55 | (I) |

FLOOD LIGHTING

| High Pressure Sodium Vapor | Average Lumens | Monthly Base Rate | Power Supply Adjustment | |
|---|---|---|---|---|
| 200 Watt | 19,800 | $ 15.23 | $ 0.26 | (I) |
| 400 Watt | 45,000 | $ 18.04 | $ 0.55 | (I) |
| Metal Halide | | | | |
| 400 Watt | 28,800 | $ 13.19 | $ 0.54 | (I) |
| 1,000 Watt | 88,000 | $ 21.14 | $ 1.27 | (I) |

2. For New Facilities Installed Before August 8, 2005. The Monthly Charge for New Facilities installed, prior to August 8, 2005 such as overhead secondary conductor, poles, anchors, etc., shall be 1.51 percent of the estimated installed cost thereof.

3. For New Facilities Installed On or After August 8, 2005. The non-refundable charge for New Facilities to be installed, such as underground service, overhead secondary conductor, poles, anchors, etc., shall be equal to the work order cost.

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

POWER FACTOR ADJUSTMENT

Where the Customer's Power Factor is less than 90 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by 90 percent and dividing by the actual Power Factor.

TEMPORARY SUSPENSION

When a Customer has properly invoked Rule G, Temporary Suspension of Demand, the Basic Load Capacity, the Billing Demand, and the On-Peak Billing Demand shall be prorated based on the period of such suspension in accordance with Rule G. In the event the Customer's metered demand is less than 1,000 kW during the period of such suspension, the Basic Load Capacity and Billing Demand will be set equal to 1,000 kW for purposes of determining the Customer's monthly Minimum Charge.

MONTHLY CHARGE

The Monthly Charge is the sum of the Service Charge, the Energy Charge, and the Power Supply Adjustment at the following rates, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

| SECONDARY SERVICE | Summer | Non-Summer | |
|---|---|---|---|
| Service Charge, per month | \$222.00 | \$222.00 | |
| Basic Charge, per kW of Basic Load Capacity | \$ 0.60 | \$ 0.60 | (I) |
| Demand Charge, per kW of Billing Demand | \$ 5.02 | \$ 4.91 | (I) |
| On-Peak Demand Charge, per kW of On-Peak Billing Demand | \$ 0.83 | n/a | (I) |
| Energy Charge, per kWh | | | |
| On-Peak | 6.0762¢ | n/a | (I) |
| Mid-Peak | 4.7841¢ | 4.5160¢ | (I) |
| Off-Peak | 4.2258¢ | 4.0852¢ | (I) |
| Power Supply Adjustment*, per kWh | 0.3507¢ | 0.3507¢ | |

*Note: A Customer who prepays the Power Supply Adjustment amount pursuant to ORS 757.259(11) shall not be subject to the Power Supply Adjustment rates.

Facilities Charge
None

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

MONTHLY CHARGE (Continued)

| PRIMARY SERVICE | Summer | Non-Summer | |
|---|---|---|---|
| Service Charge, per month | $208.00 | $208.00 | |
| Basic Charge, per kW of Basic Load Capacity | $ 1.24 | $ 1.24 | (I) |
| Demand Charge, per kW of Billing Demand | $ 5.97 | $ 4.83 | (I) |
| On-Peak Demand Charge, per kW of On-Peak Billing Demand | $ 0.87 | n/a | (I) |
| Energy Charge, per kWh | | | |
| On-Peak | 5.2455¢ | n/a | (I) |
| Mid-Peak | 4.1382¢ | 3.9206¢ | (I) |
| Off-Peak | 3.6601¢ | 3.5506¢ | (I) |
| Power Supply Adjustment*, per kWh | 0.3507¢ | 0.3507¢ | |

*Note: A Customer who prepays the Power Supply Adjustment amount pursuant to ORS 757.259(11) shall not be subject to the Power Supply Adjustment rates.

Facilities Charge

The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.41 percent.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

MONTHLY CHARGE (Continued)

| TRANSMISSION SERVICE | Summer | Non-Summer | |
|---|---|---|---|
| Service Charge, per month | $215.00 | $215.00 | |
| Basic Charge, per kW of Basic Load Capacity | $ 0.33 | $ 0.33 | (I) |
| Demand Charge, per kW of Billing Demand | $ 4.98 | $ 4.70 | (I) |
| On-Peak Demand Charge, per kW of On-Peak Demand | $ 0.95 | n/a | (I) |
| Energy Charge, per kWh | | | |
| On-Peak | 5.0849¢ | n/a | (I) |
| Mid-Peak | 4.0462¢ | 3.8258¢ | (I) |
| Off-Peak | 3.5954¢ | 3.4790¢ | (I) |
| Power Supply Adjustment*, per kWh | 0.3507¢ | 0.3507¢ | |

*Note: A Customer who prepays the Power Supply Adjustment amount pursuant to ORS 757.259(11) shall not be subject to the Power Supply Adjustment rates.

Facilities Charge

The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.41 percent.

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

# SCHEDULE 24
## AGRICULTURAL IRRIGATION SERVICE
(Continued)

## MONTHLY CHARGE

The Monthly Charge is the sum of the following charges, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), Schedule 95 (Adjustment for Municipal Exactions), and Schedule 98 (Residential and Small Farm Energy Credit).

| SECONDARY SERVICE | In-Season | Out-of-Season | |
|---|---|---|---|
| Service Charge, per month | $ 16.85 | $ 3.00 | |
| Demand Charge, per kW of Billing Demand | $ 7.98 | $ 0.00 | (I) |
| Energy Charge, per kWh | | | |
| In Season | | | |
| First 164 kWh per kW of Demand | 6.4804¢ | n/a | (I) |
| All Other kWh | 6.1135¢ | n/a | (I) |
| Out-of-Season | | | |
| All kWh | n/a | 6.7723¢ | (I) |
| Power Supply Adjustment, per kWh | 0.3507¢ | 0.3507¢ | |

Facilities Charge
None

| TRANSMISSION SERVICE | In-Season | Out-of-Season | |
|---|---|---|---|
| Service Charge, per month | $144.00 | $ 3.00 | |
| Demand Charge, per kW of Billing Demand | $ 7.47 | $ 0.00 | (I) |
| Energy Charge, per kWh | | | |
| In Season | | | |
| First 164 kWh per kW of Demand | 6.2386¢ | n/a | (I) |
| All Other kWh | 5.8866¢ | n/a | (I) |
| Out-of-Season | | | |
| All kWh | n/a | 6.5167¢ | (I) |
| Power Supply Adjustment, per kWh | 0.3507¢ | 0.3507¢ | |

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.41 percent.

SCHEDULE 40
NONMETERED GENERAL SERVICE
(Continued)

MONTHLY CHARGE

The average monthly kWh of energy usage shall be estimated by the Company, based on the Customer's electric equipment and one-twelfth of the annual hours of operation thereof. Since the service provided is nonmetered, failure of the Customer's equipment will not be reason for a reduction in the Monthly Charge. The Monthly Charge shall be computed at the following rate and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), and Schedule 95 (Adjustment for Municipal Exactions).

| | | |
|---|---|---|
| Energy Charge, per kWh | 8.302¢ | (I) |
| Power Supply Adjustment, per kWh | 0.3507¢ | |
| Minimum Charge, per month | $ 1.50 | |

ADDITIONAL CHARGES

Applicable only to municipalities or agencies of federal, state, or county governments with an authorized Point of Delivery having the potential of intermittent variations in energy usage.

| | |
|---|---|
| Intermittent Usage Charge, per unit, per month | $ 1.00 |

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

SERVICE OPTIONS (Continued)

"A" - Idaho Power-Owned, Idaho Power-Maintained System (Continued)

Accelerated Replacement of Existing Fixtures

In the event a Customer requests the Company perform an accelerated replacement of existing fixtures with the cut-off fixture, the following charges will apply:

1. The designed cost estimate which includes labor, time, and mileage costs for the removal of the existing street lighting fixtures.

2. $132.00 per fixture removed from service.

The total charges identified in 1 and 2 above must be paid prior to the beginning of the fixture replacement and are non-refundable. The accelerated replacement will be performed by the Company during the regularly scheduled working hours of the Company and on the Company's schedule.

Monthly Charges

The Monthly Charges are as follows, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), and Schedule 95 (Adjustment for Municipal Exactions).

Lamp Charges, per lamp (41A)

| Standard High Pressure Sodium Vapor | Average Lumens | Monthly Base Rate | Power Supply Adjustment | |
|---|---|---|---|---|
| 70 Watt | 5,540 | $ 8.24 | $ 0.10 | (I) |
| 100 Watt | 8,550 | $ 8.61 | $ 0.14 | \| |
| 200 Watt | 19,800 | $ 11.61 | $ 0.26 | \| |
| 250 Watt | 24,750 | $ 12.69 | $ 0.35 | \| |
| 400 Watt | 45,000 | $ 14.51 | $ 0.55 | (I) |

Pole Charges

For Company-owned poles required to be used for street lighting only:

| | |
|---|---|
| Wood pole | $ 1.90 per pole |
| Steel pole | $ 7.39 per pole |

Facilities Charge

Customers assessed a monthly facilities charge prior to August 8, 2005 for the installation of underground circuits will continue to be assessed a monthly facilities charge equal to 1.21 percent of the estimated cost difference between overhead and underground circuits.

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

SERVICE OPTIONS(Continued)

"A" - Idaho Power-Owned, Idaho Power-Maintained System (Continued)

Monthly Charges (Continued)

Payment

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

"B" - Customer-Owned, Idaho Power-Maintained System – No New Service

The Customer's lighting system, including posts or standards, fixtures, initial installation of lamps and underground cables with suitable terminals for connection to the Company's distribution system, is installed and owned by the Customer and maintained by Idaho Power. Customer-owned lighting systems receiving maintenance under Option B must have Idaho Power standard wattage high pressure sodium vapor lamps installed in all street lighting fixtures.

Customer-owned systems constructed, operated, or modified in such a way as to allow for the potential or actual variation in energy usage, such as through, but not limited to, the use of wired outlets or useable plug-ins, are required to be metered in order to record actual energy usage.

Energy and Maintenance Service

Energy and Maintenance Service includes operation of the system, energy, lamp renewals, cleaning of glassware, and replacement of defective photocells which are standard to the Company-owned street light units. Service does not include the labor or material cost of replacing cables, standards, broken glassware or fixtures, painting, or refinishing of metal poles. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements.

Monthly Charges

The Monthly Charges are as follows, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), and Schedule 95 (Adjustment for Municipal Exactions).

Non-Metered Service, per lamp (41B)

| Standard High Pressure Sodium Vapor Energy and Maintenance Charges | Average Lumens | Monthly Base Rate | Power Supply Adjustment | |
|---|---|---|---|---|
| 70 Watt | 5,540 | $ 2.02 | $ 0.10 | (I) |
| 100 Watt | 8,550 | $ 2.50 | $ 0.14 | |
| 200 Watt | 19,800 | $ 3.76 | $ 0.26 | |
| 250 Watt | 24,750 | $ 4.71 | $ 0.35 | |
| 400 Watt | 45,000 | $ 6.78 | $ 0.55 | (I) |

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

Payment

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

"C" - Customer-Owned, Customer-Maintained System

The Customer's lighting system, including posts or standards, fixtures, initial installation of lamps and underground cables with suitable terminals for connection to the Company's distribution system, is installed, owned, and maintained by the Customer. The Customer is responsible for notifying the Company of any changes or additions to the lighting equipment or loads being served under Option C – Non-Metered Service. Failure to notify the Company of such changes or additions will result in the termination of non-metered service under Option C and the requirement that service be provided under Option C - Metered Service.

All new Customer-owned lighting systems installed outside of Subdivisions on or after January 1, 2012 are required to be metered in order to record actual energy usage.

Customer-owned systems installed prior to June 1, 2004 that are constructed, operated, or modified in such a way as to allow for the potential or actual variation in energy usage may have the estimated annual variations in energy usage charged the Non-Metered Service - Energy Charge until the street lighting system is converted to Metered Service, or until the potential for variations in energy usage has been eliminated, whichever is sooner.

Monthly Charges

The monthly charges are as follows, and may also include charges as set forth in Schedule 55 (Power Cost Adjustment), Schedule 91 (Energy Efficiency Rider), and Schedule 95 (Adjustment for Municipal Franchise Fees). For non-metered service, the average monthly kWh of energy usage shall be estimated by the Company based on the total wattage of the Customer's lighting system and 4,059 hours of operation.

Non-Metered Service (41C)

| | | |
|---|---|---|
| Energy Charge, per kWh | 3.634¢ | (I) |

Metered Service (41CM)

| | | |
|---|---|---|
| Service Charge, per meter | $2.88 | |
| Energy Charge, per kWh | 3.633¢ | (I) |

SCHEDULE 42
TRAFFIC CONTROL SIGNAL
LIGHTING SERVICE

APPLICABILITY

Service under this schedule is applicable to Electric Service required for the operation of traffic control signal lights within the State of Oregon. Traffic control signal lamps are mounted on posts or standards by means of brackets, mast arms, or cable.

CHARACTER OF SERVICE

The traffic control signal fixtures, including posts or standards, brackets, mast arm, cable, lamps, control mechanisms, fixtures, service cable, and conduit to the point of, and with suitable terminals for, connection to the Company's underground or overhead distribution system, are installed, owned, maintained and operated by the Customer. Service is limited to the supply of energy only for the operation of traffic control signal lights.

The installation of a meter to record actual energy consumption is required for all new traffic control signal lighting systems installed on or after August 8, 2005. For traffic control signal lighting systems installed prior to August 8, 2005 a meter may be installed to record actual usage upon the mutual consent of the Customer and the Company.

MONTHLY CHARGE

The monthly kWh of energy usage shall be either the amount estimated by the Company based on the number and size of lamps burning simultaneously in each signal and the average number of hours per day the signal is operated, or the actual meter reading as applicable. The Monthly Charge shall be computed at the following rate, and may also include charges as set forth in Schedule 55 (Annual Power Cost Update), Schedule 56 (Power Cost Adjustment Mechanism), Schedule 91 (Energy Efficiency Rider), Schedule 93 (Solar Photovoltaic Pilot Program Rider), and Schedule 95 (Adjustment for Municipal Exactions).

| | | |
|---|---|---|
| Energy Charge, per kWh | 8.487¢ | (I) |
| Power Supply Adjustment, per kWh | 0.3507¢ | |

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

**DOCKET UE _____**

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ITS CUSTOMERS IN THE STATE OF OREGON DUE TO THE INCLUSION OF THE LANGLEY GULCH POWER PLANT INVESTMENT IN RATE BASE. | ) |

**IDAHO POWER COMPANY**

**DIRECT TESTIMONY**

**OF**

**GREGORY W. SAID**

**March 9, 2012**

**Q. Please state your name and business address.**

A. My name is Gregory W. Said and my business address is 1221 West Idaho Street, Boise, Idaho.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Vice President of Regulatory Affairs.

**Q. Please describe your educational background and business affiliations.**

A. In May of 1975, I received a Bachelor of Science Degree in Mathematics with honors from Boise State University. In 1999, I attended the Public Utility Executives Course at the University of Idaho and am now on the faculty of that program covering "Regulation and Ratemaking." I have attended numerous additional educational conferences throughout my career at Idaho Power and am an active member of the Edison Electric Institute's Rates and Regulatory Affairs Committee.

**Q. Please describe your work experience with Idaho Power.**

A. I was hired by Idaho Power in 1980 as an analyst in the Resource Planning Department. In 1985, the Company applied for a general revenue requirement increase. I was the Company witness addressing power supply expenses.

In August of 1989, after nine years in the Resource Planning Department, I was offered and I accepted a position in the Company's Rate Department. With the Company's application for a temporary rate increase in 1992, my responsibilities as a witness were expanded. While I continued to be the Company witness concerning power supply expenses, I also sponsored the Company's rate computations and proposed tariff schedules in that case.

Because of my combined Resource Planning and Rate Department experience, I was asked to design a Power Cost Adjustment ("PCA") that would impact customers' rates based upon changes in the Company's net power supply expenses. I presented my recommendations to the Idaho Public Utilities Commission in 1992, at which time the Idaho Public Utilities Commission established the PCA as an annual adjustment to the Company's rates. The Company now has a power cost adjustment mechanism in Oregon as well, which resulted from years of discussion with Oregon Staff and the parties prior to the Public Utility Commission of Oregon's ("Commission") approval. I was involved in those discussions.

In 1996, I was promoted to Director of Revenue Requirement. I managed the preparation of revenue requirement information for regulatory proceedings until 2008.

In 2008, I was promoted to Director of State Regulation, overseeing the management of both cost-of-service and rate design.

In 2010, I was promoted to General Manager of the Regulatory Affairs Department and, in 2011 I was promoted to Vice President of Regulatory Affairs.

As the Vice President of Regulatory Affairs, I oversee and direct the activities of the Regulatory Affairs Department. These activities include the development of jurisdictional revenue requirements, the oversight of the Company's rate adjustment mechanisms, the preparation of cost-of-service studies, the preparation of rate design analyses, and the administration of tariffs and customer contracts. I also have the primary responsibility for corporate policy regarding matters related to the economic regulation of Idaho Power. I have submitted testimony to the Commission on numerous occasions.

## I. OVERVIEW

**Q. What is the Company requesting from the Commission in this proceeding?**

A. The Company is asking the Commission to review the investments the Company has made to develop and integrate the Langley Gulch Power Plant ("Langley" or "Project") into the Company's operating system and approve an adjustment to the

Company's rates to reflect those investments and certain related expenses. This investment includes generation and transmission investments, as well as labor and non-labor operations and maintenance ("O&M") expenses. The Company proposes that the rate adjustment associated with Langley occur on July 1, 2012 to coincide with the anticipated online date of the resource.

**Q. What is the purpose of your testimony?**

A. My testimony:

- Describes the integrated resource plan ("IRP") process that led to the acquisition of Langley;
- Explains why the Company used a streamlined competitive bidding process to acquire Langley;
- Describes the regulatory oversight of the Langley acquisition by the Idaho Public Utilities Commission ("IPUC");
- Presents the Company's request for approval in this case; and
- Presents the revenue requirement impact of this investment and the Company's proposed rate spread.

**Q. Please summarize your exhibits.**

A. Exhibit Idaho Power/101 is the Certificate of Public Convenience and Necessity ("CPCN") for Langley issued by the IPUC. Exhibit Idaho Power/102 is a summary of actual and projected Langley investments by plant account. Exhibit Idaho Power/103 is a copy of the Company's jurisdictional separation study used to derive the Oregon revenue requirement and is based upon amounts from the investments that have not previously been addressed in ratemaking proceedings. Exhibit Idaho Power/104 details the spread of the Oregon revenue requirement to customer classes based on the methodology utilized per the settlement stipulation approved in the Company's last general rate case, Docket UE 233.

**Q. Please introduce the other witness filing direct testimony in this proceeding.**

A. Lisa A. Grow, Senior Vice President of the Power Supply Department, provides testimony describing the request for proposal ("RFP") process used to select the Langley Gulch power plant, quantifying the Company's investment in Langley Gulch, and discussing the expected completion and in-service date for the Langley Gulch Power Plant. She also provided the anticipated Langley Gulch plant investments for the end of June 2012. That amount was $398,133,778.

## II. INTEGRATED RESOURCE PLAN

**Q. Please describe the IRP process that led to the acquisition of Langley.**

A. In its Commission-acknowledged 2004 IRP, the Company identified a need for a 500 MW baseload pulverized coal-fired resource in 2011. In its acknowledged 2006 IRP, the Company reassessed when it would need to add a coal-fired resource and adjusted its long-term resource plan to include a 250 MW pulverized coal-fired resource in 2013 and a 250 MW advanced coal-fired resource in 2017.

In July of 2008, Idaho Power filed an update to its acknowledged 2006 IRP in which it notified the Commission that due to various uncertainties associated with coal-fired generation, the Company had decided not to proceed with the previously planned coal-fired resources ("2008 IRP Update"). The 2008 IRP Update also noted that the Company had decided to issue a Request for Proposals ("RFP") for tolling agreements and power purchase agreements for 250 MW to 600 MW of dispatchable, physically delivered firm or unit contingent energy deliverable in 2012 that would be measured against a self-build option ("2012 Baseload Resource").

**Q. Why did the Company shift its resource planning from acquiring two 250 MW coal plants in 2013 and 2017 to one 250 to 600 MW resource in 2012?**

A. The Company determined that due to uncertainties associated with permitting a coal facility and future carbon regulation and the increasing costs of developing coal-fired resources, the plan to develop a coal fired resource was no longer feasible. The Company therefore determined that it would issue an RFP using a natural gas-fired combined cycle combustion turbine ("CCCT") as the benchmark resource.

In addition, three events caused the timing of the resource acquisition to shift to 2012 rather than 2013 and 2017. First, due to changes in federal water policy, the Company anticipated reduced levels of hydro generation in peak summer months. Second, the combined heat and power and geothermal resource development did not materialize as robustly as expected in the 2006 IRP, and the developers' forecasts for PURPA generation did not materialize relative to their contract commitments used in the 2006 IRP. Third, the Company received a number of requests for service from new large industrial commercial loads to commence in the 2009 to 2012 period. As a result, the Company determined that it would need to have a new baseload resource on line by 2012, rather than in 2013 and 2017.

**Q. Was the IRP that reflected the change in resource type and timing acknowledged by the Commission?**

A. Yes. The Company's 2009 IRP included the 2012 Benchmark Resource and was acknowledged by the Commission. Order No. 10-392.

## III. COMPETITIVE BIDDING PROCESS

**Q. Did the Company issue the RFP it referenced in the 2008 IRP Update?**

A. Yes. The Company issued the RFP for the 2012 Baseload Resource in April of 2008. The RFP evaluation process concluded that the Langley Project provides the greatest value for customers.

**Q. Did the Company employ an RFP process that was more streamlined than the Competitive Bidding Guidelines ("Guidelines") issued by the Commission in UM 1182?**

A. Yes, it did.

**Q. Why did the Company use a more streamlined process?**

A. The Company did not have enough time to complete the Oregon competitive bidding process or obtain a waiver under the Guidelines and still have the resource on line by 2012.

**Q Please explain.**

A. The factors causing Idaho Power to shift from a coal resource to a gas-fired resource were not unique to Idaho Power. By the spring of 2008, a number of electric utilities and other generators were abandoning plans for coal plants in favor of CCCTs. Demand for CCCTs was at an all-time high, and as a result, orders for the generating equipment (turbines, heat recovery equipment, and generators) and the engagement of construction contractors needed to be completed years in advance. For these reasons, the Company determined that if it were to follow all of the Commission's Guidelines, (1) it would most likely be unable to secure generating equipment and engage a construction contractor in time to ensure that the Benchmark Resource CCCT would be available if it were selected as the best possible alternative to meet customer demand; and (2) other bidders that intended to construct a CCCT to deliver firm energy under a power purchase agreement would likely face the same equipment acquisition deadlines. Therefore, the Company found itself in a position that required a streamlined RFP process.

**Q. Did the Company notify the Commission that it intended to employ a streamlined competitive bidding process?**

A. Yes, it did. On April 8, 2008, the Company filed a pleading with the Commission in docket UM 1378 explaining the changed circumstances and requesting a waiver of the Guidelines. In so doing, it hoped not only to explain to the Commission the reasons why it needed to proceed quickly with an RFP, but also to seek input from the Commission as to the streamlined RFP process. Staff made clear that it would oppose the request for waiver, and as negotiations with Staff stretched on, the Company realized that it was really too late to receive meaningful input from the Commission. For that reason, the Company withdrew its filing.

**Q. How would you characterize the RFP process used by the Company in acquiring Langley?**

A. The RFP process used by the Company, which is described in the testimony of Lisa Grow, was rigorous, fair, and the subject of oversight by the IPUC, the jurisdiction in which the Company conducts 95 percent of its business.

## III. <u>IDAHO REGULATORY PROCESS</u>

**Q. Did the Company file an application for a CPCN with the IPUC prior to the construction of Langley?**

A. Yes. On March 6, 2009, the Company filed an Application with the IPUC requesting a CPCN authorizing the construction of Langley and requesting recognition that the Project could result in an increase to Idaho Power's rate base. IPUC Case No. IPC-E-09-03. The application was filed pursuant to Idaho Code § 61-541, which provides a public utility with the ability to file an application with the Commission for an order specifying in advance the ratemaking treatments that shall apply when the costs of the proposed facility are included in the utility's revenue requirement for ratemaking purposes.

**Q. Did the Company receive a CPCN in that case?**

A. Yes. On September 1, 2009, in Order No. 30892 the IPUC approved the Company's request for a CPCN with authorization and binding commitment to provide rate base treatment for the Company's capital investment in Langley. The IPUC issued Certificate No. 486 for the Langley Gulch Power Plant, a copy of which is attached as Exhibit Idaho Power/101.

## IV. REQUEST FOR APPROVAL IN THIS PROCEEDING

**Q. When does Idaho Power propose to begin recovering its investment in Langley in Oregon rates?**

A. The Company requests that the Commission approve the tariff sheets allowing for recovery of the revenue requirement associated with Langley effective July 1, 2012.

**Q. In your opinion, will Langley be used and useful on July 1, 2012?**

A. Yes. Based on the information provided to me by Lisa Grow, I believe Langley will be used and useful on or before July 1, 2012.

**Q. Why did the Company not include Langley in its most recent general rate case in Oregon, Docket UE 233?**

A. The Company filed its most recent rate case on July 29, 2011. The statutory suspension period in that case ended on June 1, 2012. Because Langley would not be on line until after the end of the suspension period and when rates would have gone into effect in that case, the Company did not include Langley in its filing.

**Q. Why is it appropriate to evaluate the Company's investment in Langley in this proceeding rather than in another general rate case?**

A. Rates in UE 233 went into effect on March 1, 2012, approximately a week before the Company makes this filing. It would be administratively inefficient and a waste of the resources of not only the Company, but also the Commission, Staff, and intervenors, for the Company to file another general rate case to recover the costs associated with Langley so closely on the heels of that case.

**Q. Doesn't the Company's proposed course of action constitute single issue ratemaking, which is generally disfavored by the Commission?**

A. While I am aware that the Commission generally disfavors single issue ratemaking, it has on occasion engaged in single issue ratemaking when circumstances warrant. For example, the Commission allowed Portland General Electric Company's ("PGE")

Port Westward facility to be included in rates outside of a general rate case. In that case, the Commission found that if the facility came on line shortly after rates from the most recent rate case went into effect, the resource could go into rates without reexamination of the costs and revenues established in the general rate case. Order No. 07-015 at 50. In this case, the Commission and parties also just completed a comprehensive review of the Company's costs and revenues, which should mitigate any concerns the Commission might otherwise have.

## V. <u>LANGLEY GULCH POWER PLANT INVESTMENT</u>

**Q. What is the total investment related to the Langley Project that the Company anticipates will be booked by June 30, 2012?**

A. The Company anticipates booking $398,133,778 of investment associated with the Langley Project by June 30, 2012.

**Q. Is the projected investment of $398,133,778 the amount of investment proposed in this case?**

A. No. The total investment associated with the Langley Gulch Power Plant the Company is requesting recovery of in this filing is $390,942,172.

**Q. Please explain the difference.**

A. There were a number of expenditures that were "closed to plant," or included in the Company's plant balances, by December 31, 2010. These expenditures were associated with site procurement, water rights, and water line land. Because the Company used plant balances through December 31, 2010 as the "base year" amounts for its test year forecast in its last general rate case filing (Docket UE 233), those amounts are effectively already included in the Company's current rates. Therefore, those amounts have been excluded from this request to avoid any double counting.

**Q. What are some of the components that makeup the above-referenced $390,942,172 investment in Langley?**

A. The largest portion of the $390,942,172 is related to the EPC contract for approximately $220.6 million. The gas turbine and steam turbine make up another large portion of the total investment for a combined $115.3 million.

**Q. What other components makeup the $390,942,172?**

A. In addition to the EPC contract and gas and steam turbines, the $390,942,172 includes investments in air permitting, water line construction, gas line construction, capitalized property taxes, Idaho Power engineering and oversight, RFP pricing components, transmission and miscellaneous equipment.

**Q. What additional investments will the Company make in Langley prior to June 30, 2012?**

A. During the months of February, March, April, May, and June, the Company anticipates booking an additional $34 million in Langley investments. The majority of the investment to be made during the remaining months before commercial operation is related to the EPC contract. The Company will also have an investment in start-up fuels in May and June 2012. A summary of the anticipated investments by plant account for February, March, April, May, and June is attached as Exhibit Idaho Power/102.

## VI. <u>REVENUE REQUIREMENT</u>

**Q. Have you quantified the change in the Company's Oregon jurisdictional revenue requirement as a result of the addition of the Company's investment in Langley?**

A. Yes. Exhibit Idaho Power/103 demonstrates the change in the Company's Oregon jurisdictional revenue requirement from the level determined in Docket UE 233, the Company's last general rate case. The change in the revenue requirement is due solely to the addition of the Langley investment booked as of June 30, 2012 and associated expenses. The Company has quantified the revenue requirement based upon an overall rate of return ("ROR") of 7.757% which is currently in effect and was authorized by the Commission in Order No. 12-055.

**Q. What are the associated expenses that are included in this filing?**

A. Along with the investment in Langley, the Company has included the related depreciation expense and reserve adjustment, property tax expense, property insurance expense, and labor and non-labor O&M expenses. Changes in these expenses have been included because they are a direct result of the new plant addition and can be quantified at this time. Exhibit Idaho Power/103 details the expenses included in this filing.

**Q. Please describe these expenses.**

A. In anticipation of the plant coming on line, the Company contracted with Gannett Fleming, Inc. to perform a new depreciation study, which was recently filed with the Commission in Docket UM 1576. The depreciation expense and reserve adjustments were calculated using the results of this new depreciation study. The Company's depreciation consultant, John J. Spanos, performed an on-site visit to Langley and included Langley depreciation rates in his study. Depreciation expense will increase approximately $13 million on a system basis, or $600,000 on an Oregon jurisdictional basis which results in a reserve adjustment of approximately $6.5 million or $300,000 on an Oregon jurisdictional basis.

Property tax and property insurance expenses were estimated using the June 30, 2012 projected Langley investment value. Property insurance premiums have been provided by the insurer. These expenses are approximately $1.4 million and $230,000 on a system basis, respectively.

The Company has included the additional $2 million of labor associated with the hiring of 17 new full-time employees stationed at the plant that occurred in the second half of 2011 but was not included in the Company's test year expenses approved in Docket UE 233. Non-labor O&M of $2.6 million associated with chemicals and consumables that are required to run the plant has also been included. The Oregon jurisdictional share of labor is approximately $92,000 and non-labor O&M is approximately $124,000.

**Q. The addition of Langley as a resource will provide a benefit to customers through reduced power supply expenses. Did the Company reflect the reduced power supply costs in this filing?**

A. No. However, the Company included the reduction in the net power supply expenses as a result of the additional resource in its Annual Power Cost Update filed in Docket UE 242. The Company's filed net power supply expenses in UE 242 of approximately $103.8 million on a total system basis included Langley Gulch as a resource.[1] A comparison of the Company's filed net power supply expenses to a second AURORA run that does not include Langley Gulch, shows that the inclusion of Langley Gulch provides a benefit to customers of approximately $2.6 million on a total system basis.

**Q. What is the increase in the Oregon jurisdictional share of the total combined rate base which results from including the Company's investment in Langley?**

A. As shown on Exhibit Idaho Power/103, the Oregon jurisdictional share of the total combined rate base is increased by $15,293,072. The total is comprised of the plant investment in Langley of $16,968,370, less $296,447 for accumulated depreciation,

[1] Docket UE 242, Idaho Power 101/Wright 1.

less $1,387,883 for accumulated deferred income taxes, plus $9,032 for working capital and results in the $15,293,072 increase in total combined rate base.

**Q. What are the changes to the Oregon jurisdictional share of the operating income as a result of adding Langley?**

A. Oregon net operating income decreases by $671,000 with the addition of Langley, as can be seen on Exhibit Idaho Power/103. This is the result of total operating expenses increasing by $671,000.

**Q. What is the Oregon jurisdictional revenue deficiency with the addition of Langley?**

A. The revenue deficiency for the Oregon jurisdiction is $3,049,660 as shown on Exhibit Idaho Power/103.

**Q. What percentage increase is required in rates in order to recover the $3,049,660 revenue deficiency for the Oregon jurisdiction?**

A. An increase in Oregon jurisdictional revenue of 7.32% is needed in order to recover the $3,049,660 revenue deficiency for the Oregon jurisdiction.

## VII. REVENUE SPREAD AND RATE DESIGN

**Q. What is the Company's proposed method of assigning the revenue deficiency of $3,049,660 to individual classes of customers?**

A. The Company proposes to assign the revenue deficiency of $3,049,660 to customer classes based on the final stipulated revenue spread methodology utilized in the Docket UE 233. This methodology spread generation-related revenue requirement to customer classes proportionally to the total marginal cost of generation for each rate class as determined by the stipulated class cost-of-service study. Additionally final class percentage rate increases were subject to a cap at one-and-one half times the average overall rate increase.

**Q. What are the results of applying this methodology to the $3,049,660 revenue deficiency?**

A. Exhibit Idaho Power/104 provides the allocated dollar amounts and proposed percentage increases for each rate class based on the methodology. Line 3 of Exhibit Idaho Power/104 contains the total marginal cost of generation for each rate class as stipulated in UE 233, and line 6 contains the spread of the $3,049,660 revenue requirement based on these amounts. After the revenue deficiency was spread in this manner, no rate class exceeded the one-and-one-half times average cap; therefore, the allocation of the revenue deficiency results in a pure cost-of-service revenue spread.

**Q. What is Company's proposal with regard to rate design in this case?**

A. The Company proposes to increase all base rate components for each customer class on a uniform percentage basis, with the exception of the service charge. The Company is not recommending changes to the service charges in this case because the service charge is generally associated with the recovery of metering, customer service and billing costs and not with cost recovery related to generating facilities.

## VIII. <u>TARIFF RATES</u>

**Q. Has the Company prepared tariff sheets to reflect the incremental increase in the Company's revenue requirement?**

A. Yes. Included with this application are tariff sheets setting forth the proposed rates that reflect the revenue requirement for providing retail electric service to the Company's customers in the State of Oregon for service starting on July 1, 2012.

**Q. Does this conclude your direct testimony in this case?**

A. Yes.

# BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

## IDAHO POWER COMPANY

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Exhibit Accompanying Testimony of Gregory W. Said
Certificate of Public Convenience and Necessity ("CPCN")

March 9, 2012

## BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

| | | |
|---|---|---|
| **IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE LANGLEY GULCH POWER PLANT** | ) | **CASE NO. IPC-E-09-03**<br>**CERTIFICATE NO. 486** |

On March 6, 2009, Idaho Power Company filed an Application for a Certificate of Public Convenience and Necessity to construct a new 330 MW natural gas-fired generating plant pursuant to *Idaho Code* § 61-526. The plant is to be constructed on a 137-acre parcel of land on the south side of Interstate 84 in Payette County approximately four miles south of the town of New Plymouth, Idaho.

IT IS HEREBY CERTIFIED that the future public convenience and necessity requires and will require Idaho Power Company to construct and subsequently operate a combined-cycle combustion turbine (CCCT) power plant and related interconnection facilities at the Langley Gulch site four miles south of New Plymouth. The Langley Gulch generating plant will be located in Payette County and will be interconnected to the natural gas transmission system. Idaho Power shall operate and maintain the Langley Gulch power plant to furnish electric energy to its customers.

THIS CERTIFICATE is predicated upon and issued pursuant to the findings of fact, conclusions of law, and conditions contained in Order No. 30892 service dated September 1, 2009, in the above-referenced case.

DATED at Boise, Idaho this 17th day of February 2012.

Paul Kjellander

PAUL KJELLANDER, PRESIDENT

Mack A. Redford

MACK A. REDFORD, COMMISSIONER

Marsha H. Smith

MARSHA H. SMITH, COMMISSIONER

ATTEST:

Jean D. Jewell

Jean D. Jewell
Commission Secretary

O:IPC-E-09-03_Cert 486

Idaho Power/102
Witness: Gregory W. Said

# BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

## IDAHO POWER COMPANY

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Exhibit Accompanying Testimony of Gregory W. Said
Langley Estimated Close to Plant by Plant Account

March 9, 2012

**Langley Estimated Close to Plant**
**By Plant Account**
February 2012 thru June 2012

| | | January | February | | March | | April | | May | | June | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Plant Account** | **Description** | **Total As Of 1/31/2012** | **Additions** | **Balance** | **Additions** | **Balance** | **Additions** | **Balance** | **Additions** | **Balance** | **Additions** | **Balance** |
| **Other Production** | | | | | | | | | | | | |
| 340 | Land & Land Rights - Other Prod | **90,311.60** | | 90,311.60 | | 90,311.60 | | 90,311.60 | | 90,311.60 | | 90,311.60 |
| 341 | Structures & Improvements - Other Prod | **13,523,111.92** | 203,364.98 | 13,726,476.90 | 172,826.97 | 13,899,303.87 | 188,060.72 | 14,087,364.60 | 340,064.69 | 14,427,429.28 | 218,279.05 | 14,645,708.33 |
| 342 | Fuel Holders, Producers, Access - Other Prod | **8,282,906.05** | 124,561.05 | 8,407,467.10 | 105,856.52 | 8,513,323.62 | 115,187.19 | 8,628,510.81 | 208,289.62 | 8,836,800.44 | 133,695.92 | 8,970,496.35 |
| 343 | Prime Movers - Other Prod | **203,725,681.08** | 3,063,693.48 | 206,789,374.56 | 2,603,638.31 | 209,393,012.87 | 2,833,134.76 | 212,226,147.63 | 5,123,074.51 | 217,349,222.14 | 3,288,373.83 | 220,637,595.97 |
| 344 | Generators - Other Prod | **58,926,960.19** | 886,162.92 | 59,813,123.11 | 753,093.52 | 60,566,216.63 | 819,474.59 | 61,385,691.23 | 1,481,831.87 | 62,867,523.10 | 951,150.94 | 63,818,674.04 |
| 345 | Accessory Electric Equipment - Other Prod | **47,533,738.40** | 714,827.92 | 48,248,566.32 | 607,486.80 | 48,856,053.12 | 661,033.43 | 49,517,086.55 | 1,195,327.37 | 50,712,413.93 | 767,250.85 | 51,479,664.77 |
| **346** | **Misc Power Plant Equipment - Other Prod** | **6,085,400.36** | **91,514.24** | **6,176,914.61** | **77,772.14** | **6,254,686.74** | **84,627.32** | **6,339,314.07** | **153,029.11** | **6,492,343.18** | **98,225.57** | **6,590,568.75** |
| **Total Other Production** | | **338,168,109.61** | **5,084,124.59** | **343,252,234.20** | **4,320,674.26** | **347,572,908.46** | **4,701,518.03** | **352,274,426.49** | **8,501,617.17** | **360,776,043.66** | **5,456,976.15** | **366,233,019.81** |
| **Transmission** | | | | | | | | | | | | |
| 350 | Land & Land Rights - Transmission | **495,369.09** | | 495,369.09 | | 495,369.09 | | 495,369.09 | | 495,369.09 | | 495,369.09 |
| 352 | Structures & Improvements | **843,371.17** | 20,128.77 | 863,499.94 | 27,233.04 | 890,732.98 | 194,805.05 | 1,085,538.03 | 42,625.63 | 1,128,163.66 | 33,153.27 | 1,161,316.92 |
| 353 | Station Equipment | **5,644,099.34** | 134,707.92 | 5,778,807.26 | 182,251.89 | 5,961,059.15 | 1,303,695.32 | 7,264,754.48 | 285,263.83 | 7,550,018.31 | 221,871.87 | 7,771,890.17 |
| 354 | Towers & Fixtures | **4,660,094.79** | 265,764.88 | 4,925,859.67 | 309,692.96 | 5,235,552.63 | 264,886.32 | 5,500,438.95 | 308,814.40 | 5,809,253.35 | 264,007.76 | 6,073,261.11 |
| 355 | Poles and Fixtures | **1,552,720.78** | 88,551.56 | 1,641,272.34 | 103,188.18 | 1,744,460.52 | 88,258.83 | 1,832,719.34 | 102,895.45 | 1,935,614.79 | 87,966.09 | 2,023,580.88 |
| 356 | Overhead Conductors, Devices | **3,844,754.35** | 196,720.01 | 4,041,474.36 | 229,235.72 | 4,270,710.08 | 196,069.70 | 4,466,779.78 | 228,585.40 | 4,695,365.18 | 195,419.39 | 4,890,784.57 |
| **Total Transmission Plant** | | **17,040,409.52** | **705,873.14** | **17,746,282.66** | **851,601.79** | **18,597,884.45** | **2,047,715.22** | **20,645,599.67** | **968,184.71** | **21,613,784.38** | **802,418.37** | **22,416,202.75** |
| **Distribution** | | | | | | | | | | | | |
| 364 | Poles, Towers, & Fixtures | **393,241.44** | 16,444.57 | 409,686.00 | 23,022.39 | 432,708.40 | 95,378.49 | 528,086.89 | 105,245.23 | 633,332.12 | 82,222.84 | 715,554.95 |
| 365 | Overhead Conductors, Devices | **248,036.27** | 10,943.31 | 258,979.58 | 15,320.63 | 274,300.22 | 63,471.20 | 337,771.42 | 70,037.19 | 407,808.61 | 54,716.55 | 462,525.16 |
| 366 | Underground Conduit | **14,418.65** | 337.00 | 14,755.65 | 471.80 | 15,227.44 | 1,954.59 | 17,182.03 | 2,156.78 | 19,338.81 | 1,684.99 | 21,023.80 |
| 367 | Underground Conductors, Devices | **65,536.46** | 2,117.62 | 67,654.08 | 2,964.67 | 70,618.74 | 12,282.19 | 82,900.94 | 13,552.76 | 96,453.70 | 10,588.10 | 107,041.80 |
| 368 | Line Transformers | **383,066.57** | 14,773.24 | 397,839.81 | 20,682.54 | 418,522.35 | 85,684.80 | 504,207.15 | 94,548.75 | 598,755.90 | 73,866.21 | 672,622.11 |
| 369 | Services | **12,081.20** | 701.32 | 12,782.51 | 981.85 | 13,764.36 | 4,067.65 | 17,832.01 | 4,488.44 | 22,320.45 | 3,506.60 | 25,827.05 |
| 370 | Meters | **4,722.72** | 223.15 | 4,945.87 | 312.41 | 5,258.27 | 1,294.25 | 6,552.52 | 1,428.14 | 7,980.66 | 1,115.73 | 9,096.40 |
| **Total Distribution Plant** | | **1,121,103.30** | **45,540.20** | **1,166,643.50** | **63,756.28** | **1,230,399.79** | **264,133.18** | **1,494,532.96** | **291,457.30** | **1,785,990.26** | **227,701.01** | **2,013,691.27** |
| **General** | | | | | | | | | | | | |
| 391 | Office Furniture, Equipment | **3,329.84** | 0.00 | 3,329.84 | 0.00 | 3,329.84 | 0.00 | 3,329.84 | 347.93 | 3,677.77 | 695.85 | 4,373.62 |
| 392 | Transportation Equipment | **115,712.17** | | 115,712.17 | | 115,712.17 | | 115,712.17 | | 115,712.17 | | 115,712.17 |
| 397 | Communicaton Equipment | **105,567.75** | 0.00 | 105,567.75 | 0.00 | 105,567.75 | 0.00 | 105,567.75 | 17,868.15 | 123,435.90 | 35,736.31 | 159,172.21 |
| **Total General Plant** | | **224,609.76** | **0.00** | **224,609.76** | **0.00** | **224,609.76** | **0.00** | **224,609.76** | **18,216.08** | **242,825.84** | **36,432.16** | **279,258.00** |
| **Total** | | 356,554,232.19 | 5,835,537.93 | 362,389,770.12 | 5,236,032.34 | 367,625,802.46 | 7,013,366.42 | 374,639,168.88 | 9,779,475.26 | 384,418,644.14 | 6,523,527.70 | 390,942,171.84 |

Idaho Power/103
Witness: Gregory W. Said

# BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

# IDAHO POWER COMPANY

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Exhibit Accompanying Testimony of Gregory W. Said
Jurisdictional Separation Study

March 9, 2012

# IDAHO POWER COMPANY
## JURISDICTIONAL SEPARATION STUDY
## LANGLEY REVENUE REQUIREMENT
## FOR THE TEST YEAR ENDING DECEMBER 31, 2011

| | DESCRIPTION | ALLOC/ SOURCE | TOTAL SYSTEM | OREGON RETAIL |
|---|---|---|---|---|
| 4 | ***SUMMARY OF RESULTS*** | | | |
| 5 | **RATE OF RETURN UNDER PRESENT RATES** | | | |
| 6 | TOTAL COMBINED RATE BASE | | 351,994,174 | **15,293,072** |
| 7 | | | | |
| 8 | OPERATING REVENUES | | | |
| 9 | FIRM JURISDICTIONAL SALES | | 0 | **0** |
| 10 | HOKU 1ST BLOCK ENERGY SALES | | 0 | **0** |
| 11 | SYSTEM OPPORTUNITY SALES | | 32,274,040 | **0** |
| 12 | OTHER OPERATING REVENUES | | 0 | **0** |
| 13 | TOTAL OPERATING REVENUES | | 32,274,040 | **0** |
| 14 | OPERATING EXPENSES | | | |
| 15 | OPERATION & MAINTENANCE EXPENSES | | 28,080,105 | **225,804** |
| 16 | DEPRECIATION EXPENSE | | 13,662,682 | **592,895** |
| 17 | AMORTIZATION OF LIMITED TERM PLANT | | 0 | **0** |
| 18 | TAXES OTHER THAN INCOME | | 1,432,047 | **62,058** |
| 19 | REGULATORY DEBITS/CREDITS | | 0 | **0** |
| 20 | PROVISION FOR DEFERRED INCOME TAXES | | 64,251,378 | **2,775,767** |
| 21 | INVESTMENT TAX CREDIT ADJUSTMENT | | 11,140,104 | **481,271** |
| 22 | FEDERAL INCOME TAXES | | (64,153,899) | **(2,884,948)** |
| 23 | STATE INCOME TAXES | | (12,963,928) | **(581,846)** |
| 24 | TOTAL OPERATING EXPENSES | | 41,448,490 | **671,000** |
| 25 | OPERATING INCOME | | (10,667,818) | **(671,000)** |
| 26 | ADD: IERCO OPERATING INCOME | | 0 | **0** |
| 27 | CONSOLIDATED OPERATING INCOME | | (10,667,818) | **(671,000)** |
| 28 | RATE OF RETURN UNDER PRESENT RATES | | -3.03% | -4.39% |
| 29 | | | | |
| 30 | **DEVELOPMENT OF REVENUE REQUIREMENTS** | | | |
| 31 | RATE OF RETURN | | | **7.757%** |
| 32 | | | | |
| 33 | RETURN | | | **1,186,284** |
| 34 | EARNINGS DEFICIENCY | | | **1,857,284** |
| 35 | ADD: CWIP (HELLS CANYON RELICENSING) | | | **0** |
| 36 | DEFICIENCY WITH CWIP | | | **1,857,284** |
| 37 | | | | |
| 38 | NET-TO-GROSS TAX MULTIPLIER | | | **1.642** |
| 39 | **REVENUE DEFICIENCY** | | | **3,049,660** |
| 40 | | | | |
| 41 | FIRM JURISDICTIONAL REVENUES | | | **41,684,447** |
| 42 | PERCENT INCREASE REQUIRED | | | **7.32%** |
| 43 | | | | |
| 44 | SALES AND WHEELING REVENUES REQUIRED | | | **3,049,660** |

Idaho Power/104
Witness: Gregory W. Said

# BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

## IDAHO POWER COMPANY

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Exhibit Accompanying Testimony of Gregory W. Said
Langley Gulch Revenue Requirement Allocation

March 9, 2012

# Idaho Power Company
## Before the Oregon Public Utility Commission
## 12 Months Ending December 31, 2011
## Langley Gulch Revenue Requirement Allocation

| Line | Description | (A) TOTAL SYSTEM | (B) RESIDENTIAL (1) | (C) GEN SRV (7) | (D) GEN SRV SECONDARY (9-S) | (E) GEN SRV PRIMARY (9-P) | (F) GEN SRV TRANS (9-T) | (G) AREA LIGHTING (15) | (H) LG POWER PRIMARY (19-P) | (I) LG POWER TRANS (19-T) | (J) IRRIGATION SECONDARY (24-S) | (K) UNMETERED GEN SERVICE (40) | (L) MUNICIPAL ST LIGHT (41) | (M) TRAFFIC CONTROL (42) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Current Revenue | $41,684,447 | $16,218,238 | $1,603,557 | $7,173,437 | $820,700 | $154,995 | $112,463 | $8,445,611 | $3,336,171 | $3,689,590 | $1,015 | $127,355 | $1,315 |
| 2 | | | | | | | | | | | | | | |
| 3 | Staff Adj. Generation Marginal Cost | $39,596,454 | $13,023,020 | $1,070,493 | $6,811,409 | $857,724 | $153,168 | $22,008 | $9,452,425 | $4,581,142 | $3,587,968 | $728 | $35,449 | $922 |
| 4 | Per Stipulation - Docket No. UE 233 | | | | | | | | | | | | | |
| 5 | | | | | | | | | | | | | | |
| 6 | Incremental Langley Gulch Revenue Requirement | $3,049,660 | $1,003,014 | $82,448 | $524,605 | $66,061 | $11,797 | $1,695 | $728,012 | $352,833 | $276,340 | $56 | $2,730 | $71 |
| 7 | | | | | | | | | | | | | | |
| 8 | % Increase Required | 7.32% | 6.18% | 5.14% | 7.31% | 8.05% | 7.61% | 1.51% | 8.62% | 10.58% | 7.49% | 5.52% | 2.14% | 5.40% |

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

**DOCKET UE _____**

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ITS CUSTOMERS IN THE STATE OF OREGON DUE TO THE INCLUSION OF THE LANGLEY GULCH POWER PLANT INVESTMENT IN RATE BASE. | ) ) ) ) ) ) ) ) ) |

**IDAHO POWER COMPANY**

**DIRECT TESTIMONY**

**OF**

**LISA A. GROW**

**March 9, 2012**

**Q. Please state your name and business address.**

A. My name is Lisa A. Grow and my business address is 1221 West Idaho Street, Boise, Idaho 83702.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Senior Vice President of Power Supply.

**Q. Please describe your educational background and work experience with Idaho Power.**

A. I graduated from the University of Idaho in 1987 with a Bachelor of Science degree in electrical engineering. I received an Executive Masters of Business Administration from Boise State University in 2008. I began my career at Idaho Power after graduating from the University of Idaho in 1987, and have held several engineering positions before moving into management in 2005. In 2005, I was named Vice President of Delivery Engineering and Operations. In 2009, I was appointed to my current position as Senior Vice President of Power Supply. My current responsibilities include overseeing the operation and maintenance of Idaho Power's generation fleet, power plant engineering and construction, environmental affairs, water management, power supply planning, and wholesale electricity and gas operations.

## I. OVERVIEW

**Q. Please outline the major topics you will address in your testimony in this proceeding.**

A. In my testimony I:

- Discuss the request for proposal ("RFP") process used to select the power plant now known as Langley Gulch;
- Quantify the Company's investment in Langley Gulch; and

- Discuss the expected completion and in-service date for the Langley Gulch Power Plant.

**Q. Please summarize your exhibits.**

A. Exhibit Idaho Power/201 shows the natural gas price forecast used to evaluate bids during the RFP process described in my testimony; Exhibit Idaho Power/202 shows the total revenue requirement for each of the three short-listed projects in the RFP; Exhibit Idaho Power/203 shows the 20-year net present value ("NPV") of the difference in revenue requirement between the short-listed projects; Exhibit Idaho Power/204 is a copy of the independent third-party consultant report on the RFP; and Exhibit Idaho Power/205 details the Company's total expected investment for the Langley Gulch project when the project is completed.

## II. REQUEST FOR PROPOSALS

**Q. Please describe the Langley Gulch Power Plant.**

A. The Langley Gulch Power Plant is a natural gas-fired combined cycle combustion turbine ("CCCT") generating plant with a nameplate capacity of approximately 300 MW. The project is constructed on a parcel of land on the south side of Interstate 84 in Payette County approximately five miles south of the town of New Plymouth, Idaho. As explained in the direct testimony of Gregory W. Said, the Project is a baseload generating resource of the size and type identified in the preferred resource portfolio in the Company's Commission-acknowledged Integrated Resource Plan ("IRP").

**Q. Based upon the need for a new baseload resource as identified in the Company's IRP, did the Company begin a request for proposals ("RFP") process?**

A. Yes. On April 1, 2008, Idaho Power issued an RFP to solicit competitive proposals for a new baseload resource.

**Q. Did the Company engage an independent third-party to review the Company's competitive request for proposals and bid evaluation process?**

A. Yes. The Company retained R. W. Beck, an independent consulting firm offering a complete range of consulting and engineering services to the utility industry, to assist with and participate in the RFP process. Specifically, R. W. Beck was retained to assist with preparation of the RFP, the draft power purchase and tolling agreements, development of the evaluation criteria and manual, evaluation of the proposals received in response to the RFP, including a self-build alternative as a benchmark, and to provide assurance to the Commission and bidders that the Company evaluated all proposals submitted in response to the Company's RFP in a reasonable, fair, and defensible manner.

**Q. Please describe the parameters the Company set for the responses to the RFP.**

A. The parameters set for this RFP can be grouped into four categories: product, quantity, proposal size, and term. The product was specified as dispatchable, first call, non-recallable, physically delivered firm, or unit contingent energy, commencing not later than June 1, 2012, that is dedicated solely to Idaho Power's use. The RFP indicated that the product requirements could be met through Power Purchase Agreements ("PPA") or Tolling Agreements ("TA"). The RFP also advised that the Company would include in the bidding process a Company-developed CCCT that would provide a benchmark resource for consideration ("Benchmark Resource"). Build-and-transfer proposals were not considered in this RFP process. The quantity of dispatchable firm or unit contingent energy requested was initially specified as between approximately 250 MW and 600 MW. On June 25, 2008, the quantity was revised to approximately 300 MW. The minimum and maximum proposal sizes were initially specified as 50 MW and approximately 600 MW, respectively. When the quantity was revised to approximately 300 MW, the maximum proposal size also was adjusted to approximately 300 MW. Regarding term, each respondent was required to submit one proposal with a term of 15 years and one five-year renewal option.

**Q. Why didn't the Company allow build-and-transfer proposals?**

A. When the Company made the decision to pursue a combined cycle project, Company employees visited a number of combined cycle projects. During these site visits, Company employees observed significant design differences between similar sized projects. Simply put, some designs were much better than others.

If a build-and-transfer option was permitted, and projects with significant design differences were proposed, the evaluation process could become extremely complicated and somewhat subjective. The Company concluded that the best way to eliminate significant design differences between the proposals and assure an effective evaluation process was to prepare and issue a detailed specification with the RFP to ensure uniform design criteria among projects.

However, given the decision to accelerate the on-line date to 2012, information obtained regarding critical equipment manufacturing lead times, and the aforementioned differences in project design, the Company concluded that it did not have enough time to prepare a detailed design specification to include with the RFP materials to ensure a uniform design criteria was used for build-and-transfer proposals and release the RFP in time to meet the 2012 on-line date; therefore the build-and-transfer option was not allowed.

**Q. Please describe the response the Company received to the RFP.**

A. The Company received six proposals. One proposal was returned unopened because the bidder did not submit a Notice of Intent to Bid as required by the RFP. The five remaining valid proposals represented a total of thirteen alternative resources. The alternatives included: one PPA, nine TAs, two hybrid proposals, and the Benchmark Resource.

The nine TAs offered included three different technology classes; three TAs were for large frame simple cycle CTs, two TAs were for advanced aeroderivative simple cycle CTs, and five TAs were for 1 x 1 combined cycle CTs.

**Q. Please describe the process the Company followed to evaluate and rank the responses to the RFP.**

A. The process the Company followed to evaluate and rank the responses received in response to the RFP is outlined in the Proposal Evaluation Manual prepared for the 2012 Baseload Generation RFP. The Proposal Evaluation Manual was finalized before any of the proposals were received. The evaluation process can be characterized as a three stage screening process. In Stage 1 screening, proposals were checked against the minimum requirements set forth in the RFP. This screening involved checking proposals for completeness, minimum quantities, minimum term, addressing environmental costs, an Interconnection Feasibility Study Report, and signatures.

Stage 2 screening level, a busbar analysis, was used to determine the cost of each proposal. Levelized fixed, variable, and total costs, and non-levelized total costs at various capacity factors were calculated.

During Stage 3 screening, price and non-price factors, or criteria, were scored for each proposal using a weighted scoring system. The price factors received a total of 60 points. Price factors were based on the NPV of the estimated total revenue requirement associated with each proposal. Each proposal making it to Stage 3 screening was modeled and its impact on Idaho Power's system costs was simulated using the Aurora Electric Market Model. The results of the Aurora analysis were used to determine the NPV of the revenue requirements associated with adding that project to Idaho Power's portfolio of resources. Non-price factors received a total of 40 points. Non-price criteria included: project development, project characteristics, product characteristics, project location, environmental, credit factors, and financial strength. A total of 40 points were distributed between these six non-price criteria. Sensitivity analyses were run for high and low gas price scenarios, but these results did not impact the price and non-price scores.

**Q. How did the Company address transmission costs in the RFP process?**

A. One of the minimum requirements of the RFP was that proposals relying on a new generating resource to be developed in Idaho Power's service territory were required to submit an Interconnection Feasibility Study report prepared by Idaho Power's Delivery Planning group with their proposal. The cost estimates provided by Idaho Power's Delivery Planning group in the Interconnection Feasibility Study Reports or, in one case, a System Impact Study were used to set the transmission costs of each proposal.

**Q. What fuel cost assumptions were used in evaluating the bids?**

A. The same assumptions for the cost of fuel delivery to the Northwest Pipeline mainline tap, in $/MMBtu, were used to evaluate all proposals, including the Benchmark Resource. Any costs from the main line tap to the proposed resource locations were considered to be project specific. The natural gas price forecast used to evaluate bids showed an increase from $9.39/MMBtu in 2012 to $15.55/MMBtu in 2036. This forecast is provided as Exhibit Idaho Power/201.

**Q. How was the cost of AFUDC evaluated for the Benchmark Resource?**

A. The benchmark proposal included an estimate of AFUDC costs expected to be incurred during the construction of the project. The Benchmark Resource team's AFUDC estimate was calculated by applying a seven percent annual capitalized interest charge to the funds spent on construction of the project. The estimated AFUDC costs were added to the accumulated construction work in progress balances each month. The total amount of AFUDC included in the plant portion of the Benchmark Resource evaluation was approximately $49 million. For the Benchmark Resource proposal, this amount was included in the capitalized cost of the project, which was used to calculate the estimated revenue requirement for the Benchmark Resource.

**Q. How do the total costs of the selected Langley Gulch Project compare to the other bids received by the Company in response to the RFP?**

A. Exhibit Idaho Power/202 shows the total revenue requirement for each of the three short-listed CCCT projects. The Benchmark Resource is Project D. Exhibit Idaho Power/203 shows the 20-year NPV of the difference in revenue requirement between the short-listed three CCCT projects.

**Q. What does Exhibit Idaho Power/203 show?**

A. Exhibit Idaho Power/203 shows that the 20-year NPV of the revenue requirements for the Langley Gulch Project were $108 million less than the next closest combined cycle project on the short-list. To put the $108 million difference in perspective, it is about 3.8 percent less than the 20-year NPV of the revenue requirements of the combined cycle project finishing in second place.

**Q. How did the non-price attributes compare among the various responders to the RFP?**

A. Although each project was unique, overall, the non-price scoring for the short-listed projects was actually quite close. Less than three points separated the non-price scores for all of the short-listed projects and less than two points separated the non-price scores of the short-listed combined cycle projects. Out of a possible 40 non-price points, the scores for the short-listed combined cycle projects ranged from 30.1 to 28.6. In this RFP, the non-price scores were not a significant differentiator.

**Q. Why did the Company ultimately select the Langley Gulch Project as the preferred bidder?**

A. The Company's ultimate decision to select the Langley Gulch Project, based on the results of the RFP, was primarily dictated by its substantially lower price. The differential between the 20-year NPV of the revenue requirements of the Langley Gulch and the closest Tolling Agreement for a combined cycle project shows the second place project was approximately $108 million more expensive, and the NPV analysis for the Tolling Agreement for the third-place combined cycle project was $220 million more expensive than the Langley Gulch Project. Exhibit Idaho Power/203 shows this differential graphically.

**Q. Are there any unique issues associated with a utility-owned resource?**

A. There are certain risks and benefits associated with selecting a traditional utility rate-based project. By selecting the Langley Gulch Project, the Company and its shareholders take on project development and construction risk. Customers retain the risk of fuel cost increases under either a tolling agreement or a utility-owned resource. However, with the utility-owned resource, any savings resulting from the Project realizing a better than expected heat rate will be shared with customers through the Power Cost Adjustment Mechanism. That leaves the risk that the Company may not be able to operate and maintain the Project as efficiently as another operator. While this is a possible risk, conversely, if the Company is able to operate and maintain the Project for less than its anticipated costs, customers will have an opportunity to receive those savings. The potential operating risk needs to be balanced against the possible operating savings, plus the benefit of a projected 20-year NPV reduction in revenue requirement of $108 million, plus the residual value associated with the Langley Gulch Project at the end of 20 years. It is the Company's conclusion that the above-described benefits to customers outweigh the risks associated with developing and operating a traditional utility rate-based project.

**Q. Were there other material considerations that should be considered when reviewing the Company's bid evaluation process?**

A. Yes. There are two items that I would like to stress. The first is imputed debt. The RFP evaluation process did not assign any additional costs to the PPAs or TAs to cover the costs Idaho Power would incur by issuing additional equity to maintain its debt and equity ratios if the rating agencies imputed additional debt on Idaho Power's balance sheet as a result of entering into a long-term PPA or TA.

The second item is treatment of the costs associated with not selecting the Langley Gulch Benchmark Resource. While the Company recognizes that there may be loss of equipment deposits, reservation fees, cancellation charges, and other penalties or costs that Idaho Power would incur if the Benchmark Resource was not selected, these potential costs were not considered in the bid evaluation. If all other things were equal, PPA or TA proposals would not have had to win by more than Idaho Power's cancellation costs to have been considered the winner.

**Q. Did R. W. Beck provide a written assessment of the Company RFP process?**

A. Yes. A copy of their assessment is attached as Exhibit Idaho Power/204.

**Q. What did R. W. Beck conclude concerning the quality of the Company's RFP process?**

A. R. W. Beck concluded:

> Finally, based on our work with the Idaho Power RFP Evaluation Team as described above, we believe that the Idaho Power 2012 Baseload RFP process was conducted fairly and properly and that offers provided to Idaho Power as part of the RFP process, including the Benchmark Resource, were treated objectively and consistently as set forth in Section 5.5 of the RFP. (R. W. Beck Report, p. 3.)

**Q. Are there other attributes of the Langley Gulch Project that you believe should be important to the Commission's consideration?**

A. Yes. Although not directly evaluated in the RFP process, there are several other benefits associated with adding a combined cycle combustion turbine to Idaho Power's generation resources. First, by using new, state of the art technology, the Langley Gulch Project will benefit from technological advancements resulting in improved efficiency that can be passed through to customers in the form of reduced operating costs and greater secondary sales revenues. Second, the improved efficiency and the low variable operating costs of the Langley Gulch Project will result in the unit being dispatched more frequently. Having the unit on line more frequently provides Idaho Power with another resource to assist with integrating wind or other intermittent resources. Third, the Langley Gulch Project is expected to have a residual value, and be available to serve customers at the end of 20-years. Finally, adding a combined cycle project to Idaho Power's portfolio provides the Company with an opportunity to shift generation from coal-fired resources to a natural gas-fired combined cycle resource during certain times of the year, reducing the Company's CO2 emissions from its coal-fired resources.

**Q. What is the current status of the Langley Gulch Power Plant and related facilities?**

A. To date, the overall project for the Langley Gulch Power Plant remains on schedule. Construction is complete on the water pipeline and pump station and water is available to the plant site. Construction of the gas lateral pipeline from the Williams Northwest main to the site was completed in July 2011. Construction of the tap and metering station was substantially completed in October 2011. Williams Northwest will perform final checkout of its system prior to delivering gas in April 2012.

The construction of the 2.8 mile 230 kilovolt ("kV") line to the west of the power plant was completed in March 2011 and is currently in operation. The 16.3 mile 138 kV line is under construction and planned to be completed by May 2012.

All permits for air, water, conditional use, and the National Environmental Policy Act are completed and in the construction compliance phase. The Company continues to monitor the permit requirements and is coordinating with the regulatory agencies as needed.

## III. INVESTMENT IN LANGLEY GULCH PLANT

**Q. Are you sponsoring an exhibit that shows the Company's total expected investment for the Langley Gulch plant?**

A. Yes, Exhibit Idaho Power/205 details the Company's total expected investment for the Langley Gulch project when the project is completed. The total investment will be $401,416,575. Also shown on Exhibit Idaho Power/205 is the Company's actual spend through January 2012, the remaining dollars to be spent by the end of June, and the Company's total estimated spend through June 2012 of $398,133,778. In addition, Exhibit Idaho Power/205 shows, for comparison purposes, the Commission-approved binding cost estimate of $396,618,473.

**Q. Did the Company provide an estimate of its expected total investment in Langley to the Idaho Public Utilities Commission ("IPUC")?**

A. Yes. The Company identified a Commitment Estimate in its application in Case No. IPC-E-09-03 of $427,366,740. In Order No. 30892, the IPUC preapproved $396,618,473 for the binding recovery under Idaho Code § 61-541 ("Binding Pre-Approved Amount"). The IPUC decided on a lower amount because it agreed with IPUC Staff's approach to separate costs that are known with greater certainty and competitively procured, defined as a "soft cap," from amounts that are based on more uncertain estimates and contingencies which resulted in a difference of approximately $30.7 million. IPUC Staff indicated that costs above the Binding Pre-Approved Amount of $396,618,473 would be subject to a prudence review and IPUC approval.

**Q. How does the total expected investment in Langley Gulch of $401 million compare to the Commitment Estimate of $396 million approved in Case No. IPC-E-09-03?**

A. The Company's total investment for the Langley Gulch project will be $26 million less than the Company's Commitment Estimate filed with the IPUC, and approximately $4.8 million greater than the IPUC's Binding Pre-Approved Amount.

**Q. Please identify some of the reasons why the total expected cost of $401 million for the Langley Gulch project is $26 million below the Company's originally filed cost commitment.**

A. There are several notable reductions from the cost estimates included in both the Company's originally filed Commitment Estimate and the Binding Pre-Approved Amount of $396 million. Most notably, the Engineering, Procurement, and Construction contract will come in $5.7 million less than the pre-approved amount. In addition, capitalized property taxes will be $1.4 million less, allowance for funds used during construction will be $2.7 million less, and the gas turbine will be $37,823 less than the amounts included in the $396 million.

**Q. While the Company's expected investment in Langley Gulch is $26 million less than its original Commitment Estimate, you stated that it is $4.8 million greater than the Binding Pre-Approved Amount. Please explain why.**

A. One of the primary reasons for the differences between the Company's total investment of $401 million and the pre-approved $396 million has to do with some of the individual cost components that were included in the pre-approved amount. In Order No. 30892, the Commission separated costs that were known with greater certainty and competitively procured from amounts that were based on more uncertain estimates and contingencies. This approach resulted in the Commission's Binding Pre-Approved Amount of $396 million. Any costs the Company incurs above the pre-approved $396 million are subject to a prudency review for Commission approval.

**Q. Please describe at a high level any significant variations in the cost components included in the $396 million and the Company's total expected investment of $401 million.**

A. As is expected with any project of this magnitude, the actual costs for the Langley Gulch project were higher than estimated in some individual cost categories and lower than estimated in other cost categories. Three of the Company's projected investments that are expected to be significantly higher are expenditures related to the gas line construction, RFP pricing components, and transmission. With regard to the gas line construction, the Company's total investments are twice as much as stated in the $396 million. However, this is primarily due to the fact I just described above. Due to uncertain estimates included in the Company's original cost commitment, the Commission established the gas line construction cost estimate at only 50 percent of the Company's anticipated costs. The Company's original estimate for gas line construction was $3,100,000. The actual total spend will be $3,170,000, just $70,000 above Idaho Power's original estimate. However, by only including 50 percent of Idaho Power's original estimate, the actual costs incurred appear to be much greater than the pre-approved amount.

**Q. Please describe the increase incurred between cost estimates for the RFP pricing.**

A. RFP pricing components include the costs for the RFP team as well as the start-up fuel costs. The expected RFP pricing component costs of $5,574,298 are $5 million higher than the costs included in the $396 million. Most of this deviation comes from a combination of higher than anticipated required fuel usage during project commissioning and a lower than expected surplus energy sales offset value. In the

Company's original estimate, it was expected that commissioning would occur during the spring of 2012 when market energy prices were higher; *i.e.*, April or May, allowing the Company to offset the incurred gas costs. Now the commissioning of the plant is expected to occur during June when market energy prices are typically lower, resulting in less of an offset than was originally anticipated.

**Q. What variation in costs estimates has occurred with transmission?**

A. While actual transmission costs are $4 million above the Binding Pre-Approved Amount, the Commission-approved estimate did not include some of the Company's original contingency estimates and upgrades, resulting in a Binding Pre-Approved Amount that was a fraction of the original Commitment Estimate. Actual total transmission costs incurred are $22 million, which is $9.5 million below the Company's original Commitment Estimate.

**Q. Does the Company's request in this docket include its total investment of $401 million in the Langley Gulch project?**

A. No, not at this time. While the $401 million is $26 million less than the Company's originally filed Commitment Estimate, the Company is only requesting recovery of the amount of investment that will be closed to books by June 30, 2012, or $398,133,778. Company witness Gregory W. Said details the development of the incremental revenue requirement associated with Langley Gulch in his testimony, as it relates to the $398 million.

**Q. Does Idaho Power's current load and resource balance indicate that Langley Gulch is still needed in the summer of 2012?**

A. Yes. The peak-hour load and resource balance from the 2011 IRP was updated to include the Company's latest load forecast, which accounts for reduced load based at the Hoku Corporation facility, an updated forecast of Public Utility Regulatory Policies Act of 1978 generation taking into account recent contracts and expected on-line dates, and updated estimates of transmission capacity available for July market purchases from the Pacific Northwest. Without Langley Gulch, the updated peak-hour load and resource balance shows July deficits of 28 MW in 2012, 169 MW in 2013, and 224 MW in 2014. With the Langley Gulch plant being available this summer, Idaho Power will be able to reliably meet the summer peak needs of customers.

## IV. COMPLETION AND IN SERVICE DATE

**Q. Will Langley be in commercial operation on July 1, 2012?**

A. Yes. As defined in the Engineering, Procurement, and Construction ("EPC") contract, which is the joint venture between Kiewit Power Engineers and The Industrial Company, custody and control of Langley will be transferred to Idaho Power at the time of substantial completion. Substantial completion is expected to occur by June 30, 2012. Company ownership and operation capability of the plant will occur at that time.

**Q. Will testing of the power plant occur prior to substantial completion of the project?**

A. Yes. To achieve substantial completion status, the power plant must pass certain performance tests to verify that plant characteristics such as net capacity, net heat rate, and emission levels are within tolerances contained in the purchase agreement.

**Q. In your opinion, will the Langley Gulch power plant be used and useful on July 1, 2012?**

A. Yes. The Langley Gulch power plant is expected to be in commercial operation on or before July 1, 2012. The Langley Gulch power plant will be immediately used and useful once it is in commercial operation in order to help meet the Company's summer peak demand requirements and provide additional system reliability needed year-round due to the increased challenges of integrating variable and intermittent renewable generation resources.

**Q. Does this conclude your direct testimony in this case?**

A. Yes, it does.

Idaho Power/201
Witness: Lisa A. Grow

# BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

# IDAHO POWER COMPANY

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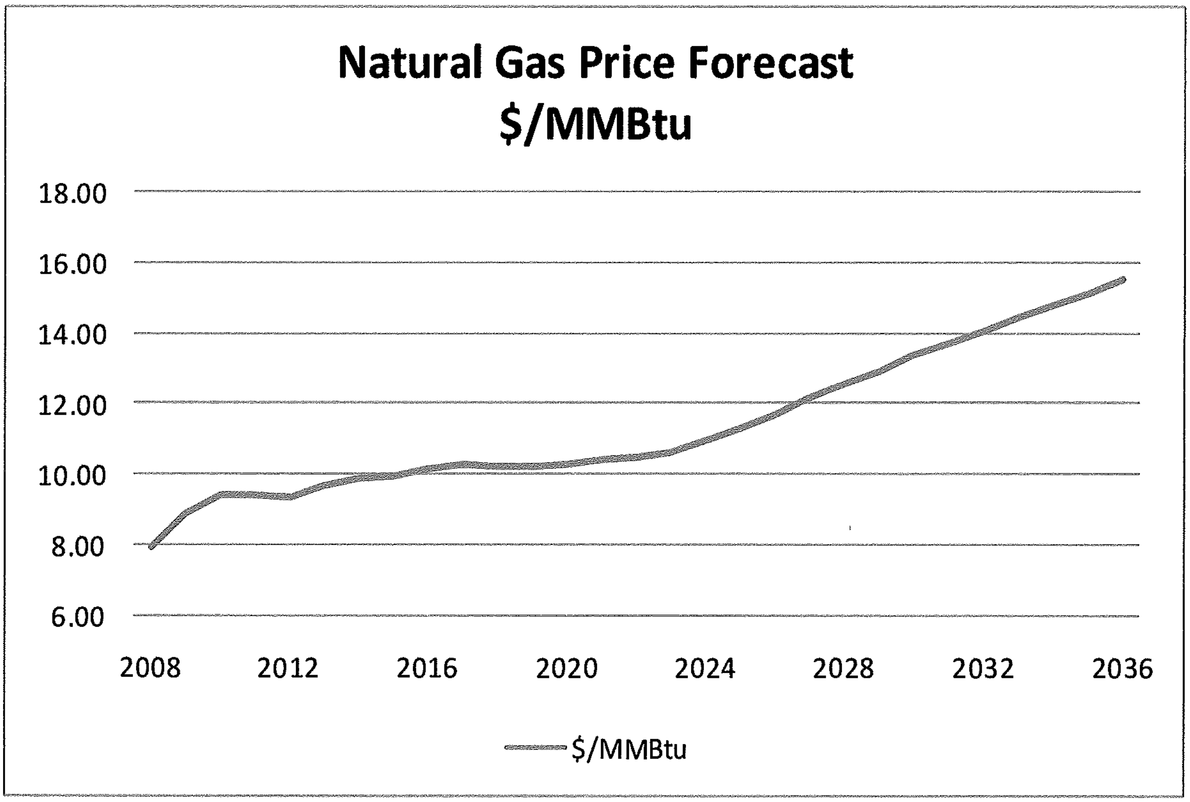
Exhibit Accompanying Testimony of Lisa A. Grow
Natural Gas Price Forecast

March 9, 2012

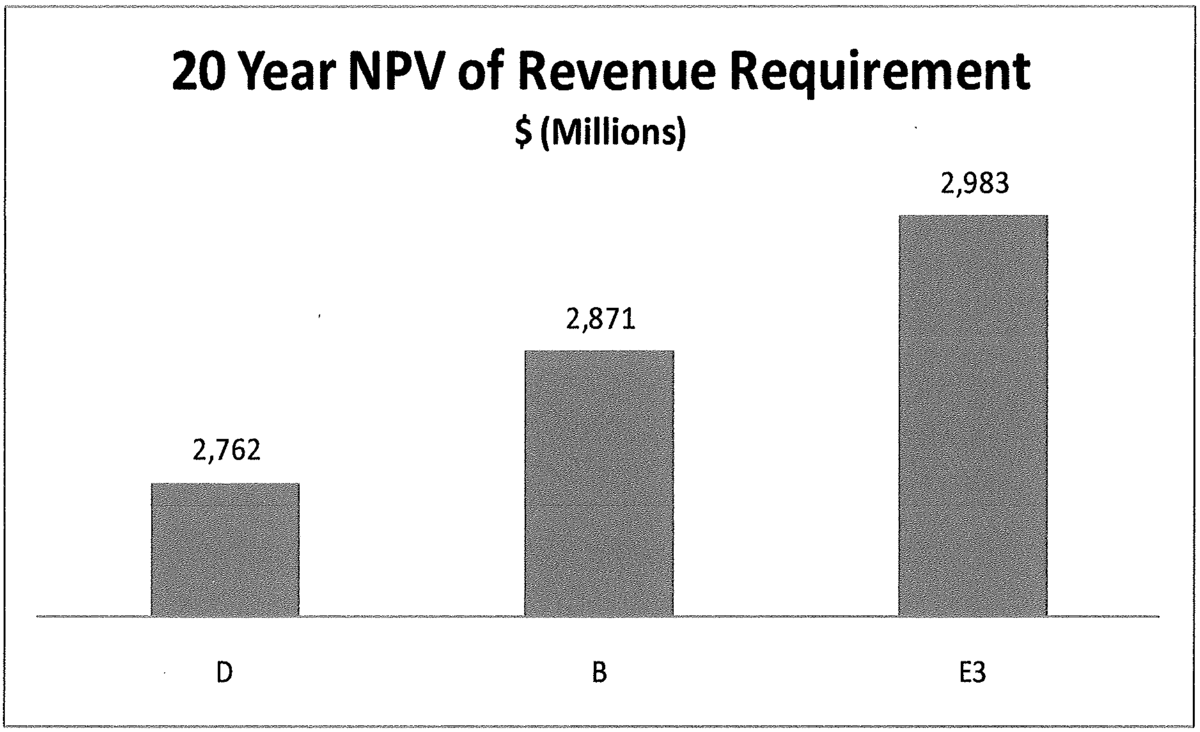

Natural Gas Price Forecast
$/MMBtu
18.00
16.00
14.00
12.00
10.00
8.00
6.00
2008
2012
2016
2020
2024
2028
2032
2036
$/MMBtu

# BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

## IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Lisa A. Grow
20 Year NPV of Revenue Requirement

March 9, 2012

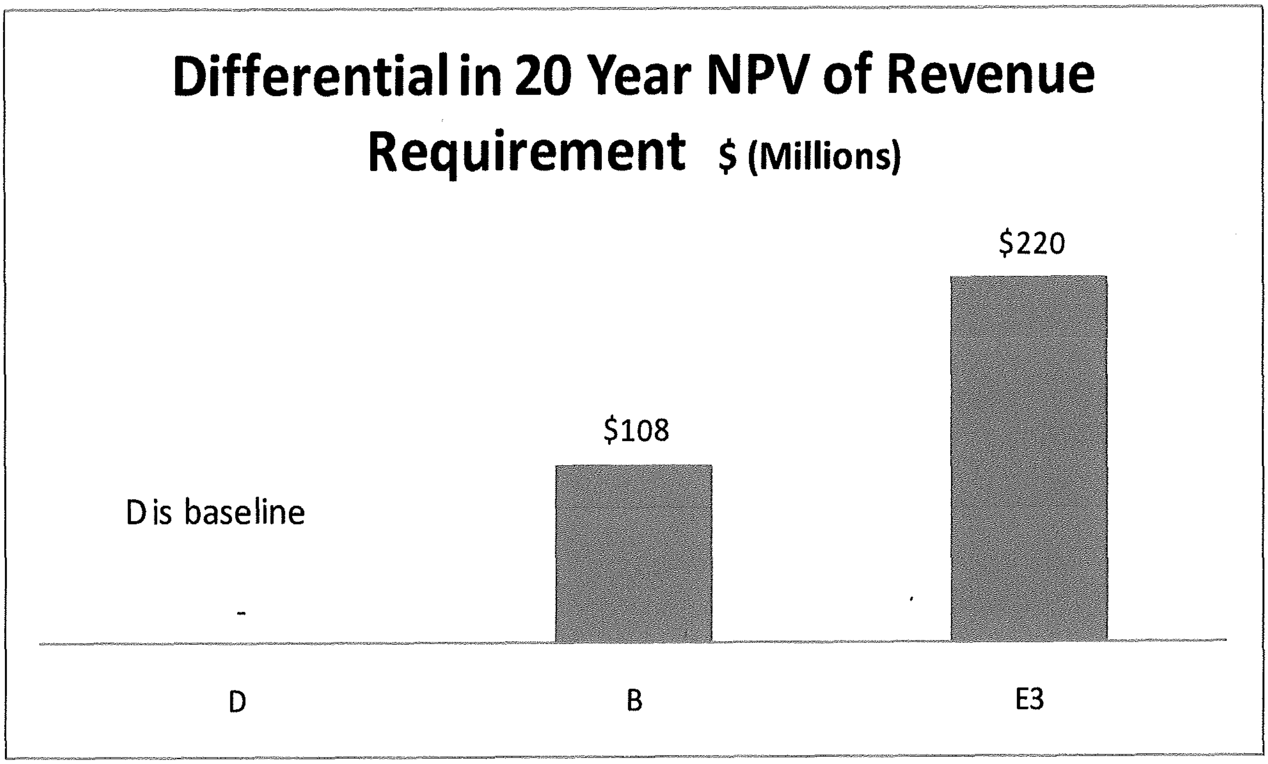

20 Year NPV of Revenue Requirement
$ (Millions)
2,762
2,871
2,983
D
B
E3

# BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

## IDAHO POWER COMPANY

Exhibit Accompanying Testimony of Lisa A. Grow
Differential in 20 Year NPV of Revenue Requirement

March 9, 2012


Differential in 20 Year NPV of Revenue Requirement $ (Millions)
$220
$108
D is baseline
-
D
B
E3

# BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

## IDAHO POWER COMPANY

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Exhibit Accompanying Testimony of Lisa A. Grow
Independent Third-Party Consultant Report on the RFP

March 9, 2012

R·W·BECK

March 5, 2009

Mr. Karl E. Bokenkamp
General Manager
Power Supply Operations & Planning
Idaho Power Company
P. O. Box 70 (83707)
1221 West Idaho Street
Boise, Idaho 83702

Subject: **Letter Report of the Independent Consultant associated with the Idaho Power Company Request for Proposal, 2012 Baseload Generation**

Dear Karl:

In accordance with your request, we are writing this letter to summarize our work related to services provided by R. W. Beck, Inc. ("R. W. Beck") to Idaho Power Company ("Idaho Power") as the "Independent Consultant" for the Idaho Power Company's Request for Proposal, 2012 Baseload Generation ("RFP"). This letter summarizes our work up to the date of this letter. Changed conditions which occur or become known after such date could affect the results presented in the letter to the extent of such changes.

As stated in Section 5.5 of the RFP, R. W. Beck was retained by Idaho Power to serve as the Independent Consultant to help ensure that the RFP process was conducted fairly and properly and that all offers were treated objectively and consistently. Section 5.5 of the RFP further stated that the Independent Consultant may:

1. "Consult with Idaho Power in preparing the RFP and evaluation criteria.
2. Consult with Idaho Power on evaluation of proposals.
3. Independently score all or a sample of the proposals to determine whether the selection of the short list is consistent with the scoring criteria.
4. Compare the result of the Independent Consultant's scoring with Idaho Power's scoring and work with Idaho Power to attempt to reconcile and resolve scoring differences.
5. Prepare reports as requested by Idaho Power including reports to the IPUC and OPUC as requested by Idaho Power."

To date, Idaho Power has requested R. W. Beck to perform tasks 1, 2 and 5 described above. This included R. W. Beck consulting with and advising Idaho Power in preparing the RFP and evaluation criteria. R. W. Beck was not requested to perform tasks 3 and 4 described above. The decision not to have R. W. Beck independently score the proposals was made in consultation with Idaho Power considering the cost and likely value of duplicating the



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evaluation process considering the advisor role R. W. Beck had played in setting up the scoring and evaluation process. As the Independent Consultant, R. W. Beck provided general advice and guidance to the Idaho Power RFP Evaluation Team in numerous ways. This work included attendance at eight meetings with the RFP Team in Boise and participation in numerous conference calls. R. W. Beck's work generally involved consultation and assistance provided to the Company for:

1. Development and execution of the overall RFP process;
2. Preparation of the RFP document;
3. Review of the Tolling Agreement and the Power Purchase Agreement available on the Idaho Power website;
4. Preparation of the Pre-Bid Meeting materials and attendance at the Pre-Bid Meeting;
5. Preparation of the evaluation criteria;
6. Preparation of responses to bidder questions;
7. Preparation of addendum;
8. Evaluation of the proposals;
9. Review of the bus bar spreadsheet (Stage 2 screening) for one proposal alternative;
10. Review of the Stage 2 screening summary results;
11. Review of the cost of service methodology (Stage 3 screening);
12. Review of the Stage 3 screening summary results;
13. The Company's conduct of the non-price scoring sessions;
14. The Company's conduct of one meeting and in conference calls during the proposal review and evaluation sessions;
15. Participation in conference call discussions concerning the selection of the short-listed bidders;
16. Participation in a conference call with the Oregon PUC staff to update the staff on the RFP process; and
17. Attendance at the face-to-face meeting with the short list bidders.

Idaho Power received five proposals that included thirteen alternatives. One of the five proposals was submitted as the Benchmark Resource by an Idaho Power team. Based on my participation in the process, it is my opinion that Idaho Power's RFP evaluation team operated in good faith to maintain confidentiality and maintain independence from the Idaho Power team preparing the Benchmark Resource proposal. Furthermore, based on our work on power supply RFPs, we believe that the RFP document and RFP process was conducted consistent with the practices used in the electric utility industry.



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Finally, based on our work with the Idaho Power RFP Evaluation Team as described above, we believe that the Idaho Power 2012 Baseload RFP process was conducted fairly and properly and that offers provided to Idaho Power as part of the RFP process, including the Benchmark Resource, were treated objectively and consistently as set forth in Section 5.5 of the RFP.

I have attached information regarding R. W. Beck's experience and professional expertise in assisting utilities in conducting RFP projects.

Very truly yours,

R. W. BECK, INC.

Steven Stein
Principal and Executive Consultant

SS/ea

Enclosure





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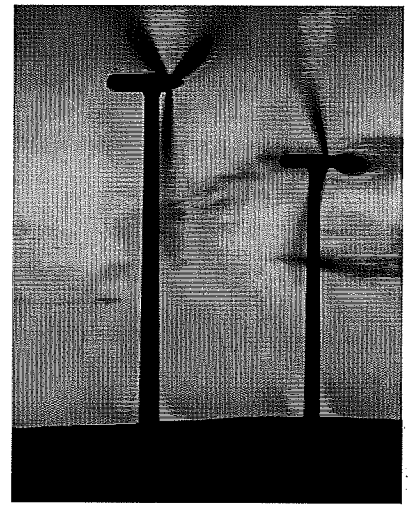


## ABOUT R. W. BECK

At R. W. Beck, our goal is to advance the business of infrastructure. Since our founding in 1942, R. W. Beck has grown to become a trusted advisor to industry leaders across the country and around the world. Today, we are a group of technically-based business consultants who provide planning, business and engineering solutions to the energy, financial, water, wastewater and solid waste industries.

We are unlike traditional engineering firms in that we provide a distinct blend of business insight, financial acumen and technical expertise to drive success for our clients - we advance their projects and business processes in a way that provides positive, lasting impacts to the communities they serve.

To do this, we integrate the talents of our staff of more than 550 engineers, economists, analysts, and other professionals to develop solutions that are always prudent and often innovative. This approach has allowed us to develop a unique work environment fueled by dedicated and creative individuals who are truly passionate about delivering world-class solutions to improve the communities where we all live and work.

We have consistently been included on the list of top engineering and design firms by industry trade publications such as *Project Finance* and *Engineering News-Record*. As a multifaceted organization, we provide the resources of a large interdisciplinary group of engineering, economic, management consulting, and environmental talent, while retaining personal relationships with our clients. We have built our strong reputation for excellence by being committed to independence, listening to our clients, and continually expanding our capabilities to meet clients' changing needs and market conditions.

Our core values, as articulated by company founder Robert W. Beck 65 years ago, remain unchanged – **scrupulous objectivity, first-class problem solving, and absolute commitment to our clients.**

## OUR PEOPLE

R. W. Beck has worked diligently to attract and maintain a staff of highly qualified, motivated professionals who enjoy working closely with our clients to solve the complex, challenging issues they face. Many of our staff members are skilled in more than one discipline and are accustomed to working closely with team members from other disciplines and industries. The result of this model is a staff whose dedication,

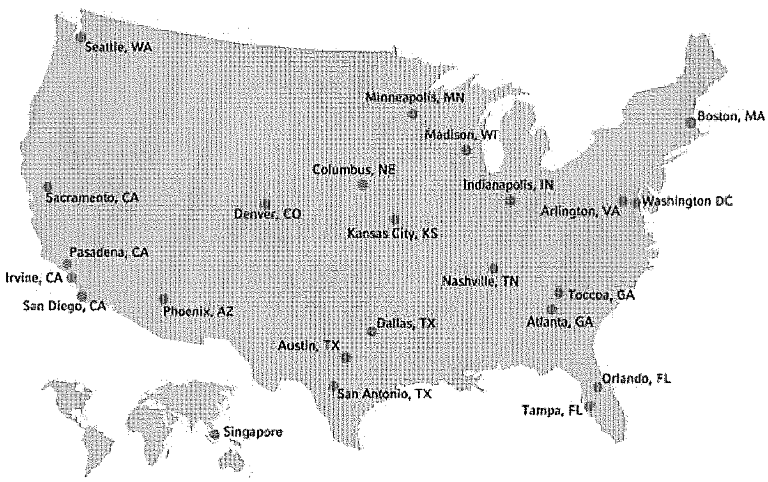
R·W·BECK

flexibility and cross-disciplinary nature is an added benefit that we pass along to our clients, and one of the reasons clients keep turning to R. W. Beck.

The consistent growth of R. W. Beck is a testament to our ability to bring value to our clients. As we look toward the future our mission will remain the same – to meet and surpass our clients' expectations with the collective experience, skills, and integrity of our most impressive resource: our people.

## OFFICE LOCATIONS

Our culture and technical expertise extends from coast to coast, allowing our clients to call on a single, seamless organization to help meet their needs.




## CORPORATE MILESTONES

**Since the firm's founding in 1942**, our accomplished staff has achieved many significant milestones across the energy, water, wastewater, and solid waste industries that allow us to mark our progress as a company.

- Provided independent engineering reviews and financial feasibility assessments associated with funding over $150 billion in capital investment
- Completed more than 150 appraisals and valuations totaling approximately $55 billion in fair market value in the past 10 years
- Performed due diligence reviews and/or designed and engineered 400+ power-related projects worldwide (approximately 50,000 MW)
- Permitted and licensed power plants, resources recovery, and industrial sites in 42 states and several U.S. territories
- Conducted more than 600 hydropower projects ranging from 60 kW to 2,000 MW of installed capacity and encompassing studies ranging form site selection to project management
- Worked on water and wastewater systems, including pipelines, pump stations, and treatment plants with capacities ranging from 5 to 200 million gallons per day

- Completed more than 21 alternative delivery projects with a total capital investment of $1.2 billion since 2000
- Completed more than 200 stormwater planning projects and 130 stormwater design projects
- Conducted more than 100 solid waste management plans for countries, states, multi-jurisdictional entities, counties, and cities

# Steven Stein, P.E.

**Florida Institute of Technology**
Master of Business Administration

**University of Central Florida**
M.S. in Industrial Engineering
B.S. in Electrical Engineering

**Registered Professional Engineer**
Alabama
Florida

**Professional Honors and Recognitions**
UCF – Alumni Service Award
UCF – Charter President, College of Engineering, Alumni Chapter
Herbert C. Westfall Leadership Award
Robert E. Bathen Entrepreneurial and Leadership Award

## KEY EXPERTISE

> Power Supply Arrangements
> Contract Negotiations
> Power Cost Projections
> Wholesale Marketing
> Transmission Services
> Procurement Services/Cogeneration
> Financial Planning and Analysis
> Mergers and Acquisitions

Mr. Stein joined R. W. Beck in 1977 and is a Principal. He has directed the preparation of power supply planning, financial and rate-related studies for individual electric utilities, joint action agencies, industrial clients and other large energy consumers. Throughout his thirty plus year career in the utility industry, he has helped clients develop energy strategies, evaluate power supply alternatives, and he has also represented clients in contract evaluation and negotiations to help achieve the most economical and reliable energy supply. Mr. Stein has presented testimony before the Federal Energy Regulatory Commission (FERC), as well as a number of state public service commissions, local district courts and other regulatory bodies.

Mr. Stein has focused his efforts over the past few years on strategic power supply and transmission policy and related regulatory issues that affect capacity and energy markets, including those established by various Regional Transmission Organizations, utilities' joint formation and joint power supply acquisitions. He has also been involved in several new areas that include location based market price forecasting, enterprise risk management, portfolio resource analysis, generation dispatch and control area operational strategies, power pools, transmission ownership opportunities and energy resource acquisitions in light of an increasingly competitive utility environment. These services have been provided in numerous market regions throughout the United States including Entergy, FRCC, PJM, MISO, SPP and SERC. Mr. Stein has provided a combination of related power supply planning services, including the development of Request for Proposals (RFP); reviewing resource proposals; establishing evaluation criteria; performing technical reviews of power plant alternatives; and negotiating contracts for the purchase of power and energy sales between electric utilities and large industrial customers. He has conducted training sessions regarding the acquisition of resources and the RFP process. With regard to the acquisition and/or development of generating resources, Mr. Stein has assisted with the development and review of contractual arrangements, the development of pro forma projections of related costs and the required transmission and related services arrangements.

Prior to joining R. W. Beck, Mr. Stein conducted generation and transmission planning studies for a large utility in the southeast. He participated in state and regional studies that addressed joint power pooling opportunities and transmission planning and reliability studies. Certain of the studies lead to the formation of the Florida Energy Broker among the electric generating utilities in Florida.

## Areas of Expertise

### Power Supply Arrangements

Mr. Stein has directed the development of various power supply studies and analyses that have considered purchasing power alternatives; ownership interest in jointly-owned units; construction of new power supply resources; refurbishment of existing facilities considering gas, oil, coal and wood fuels; cogeneration facilities and associated transmission facilities; and related transmission arrangements. This work has included the participation in contract reviews, negotiations and discussions with electric utilities, developers and vendors, and also project coordination with other technical experts and attorneys.

### Contract Negotiations

Mr. Stein has assisted electric utilities with contract negotiations on power supply arrangements. These negotiations have included discussions with other electric utilities, developers and equipment vendors concerning territorial and franchise arrangements, interchange contracts, short and long-term power exchanges, sale of reserve capacity, interconnection facilities and jointly-owned cogeneration and coal and gas fueled facilities.

### Power Cost Projections

Mr. Stein has directed the preparation of power cost projections for municipal, joint action agencies and investor-owned utilities. These projections have included utilities that range in size from 10 MW to 10,000 MW and have considered both retail cost of service concepts required by bond resolutions and state utility commissions and wholesale cost of service concepts required by bond resolutions and the FERC.

### Wholesale Marketing

Mr. Stein was responsible for conducting marketing studies for generation owners to identify potential purchasers of wholesale power in various market regions around the United States. Different techniques were employed to identify and screen potential entities, identify the amount and timing and term for capacity and energy purchases, and also to identify the characteristics of the various types of products.

### Transmission Services

Mr. Stein has assisted clients with identifying and analyzing alternative transmission strategies. These strategies were used by electric load serving entities to obtain reliable firm and unit power products to serve retail and wholesale load and by generation entities interested in interconnecting into the grid and selling various non-firm and firm wholesale power products.

### Procurement Services/Cogeneration

Mr. Stein has been a lead team member or project manager on procurement or related services for the City of North Little Rock, Arkansas; City of Benton, Arkansas; Conway Corporation, Arkansas; City of Tallahassee, Florida; the Florida Municipal Power Agency; City of Hagerstown, Maryland; Town of Front Royal, Virginia; Town of Thurmont, Maryland; Town of Williamsport, Maryland; Idaho Power Company, City of Mt. Dora, Florida, the Alabama Municipal Electric Authority; the City of St. Cloud, Florida; Golden Spread Electric Cooperative; PUD Number 1 of Snohomish County, Washington;

Kissimmee Utility Authority, Florida; Orlando Utilities Commission, Florida; and Vineland, NJ. Mr. Stein was also retained by a multilateral funding organization to participate in an intensive workshop in Nairobi, Kenya, on independent power and how to conduct a RFP process for increased capacity. Mr. Stein's presentation, "Acquiring Private Power Projects," covered competitive bidding, direct negotiations and competitive negotiations.

### Financial Planning and Analysis

Mr. Stein has prepared numerous Consulting Engineer's reports, which were used to issue electric utility revenue bonds. These reports typically include a description of the system, purpose of the issuance and historical and projected operating results showing debt service coverage. He has prepared such reports for the City of Tallahassee, Florida; City of Starke, Florida; and the Alabama Municipal Electric Authority.

Mr. Stein's experience has enabled him to analyze the financial aspects of municipal projects including bond indenture requirements, various financing methodologies, tax-exemption considerations, arbitrage and other financial related factors.

### Mergers and Acquisitions

Mr. Stein directed the preparation of studies that considered the purchase of electric utilities' facilities by the City of Fernandina Beach, Florida, at the termination of its franchise agreement. The studies included an analysis of alternative wholesale power supply arrangements and development costs required to start the new utility system. Mr. Stein also assisted the City of Winter Park, Florida in several matters related to the acquisition and purchase of the electric facilities for Progress Energy Florida.

## Relevant Project Experience

### Bulk Power Supply Arrangements

#### Central Minnesota Municipal Power Agency (CMMPA), Utilities Plus (UP)

**Project Manager.** Mr. Stein has directed the development of various strategic organizational issues relating to the relationship between CMMPA, UP and the Member utilities, contract drafting and various power supply studies and analyses. The studies and analysis have considered purchasing power alternatives, ownership interest in jointly-owned units, consideration of base load coal resources, pooling of energy resources and energy accounting, consideration of associated transmission facilities, load forecasting and needs determination before regulatory bodies. This work has included the participation in contract drafting and review, discussions with other electric utilities, coordination with other technical experts and attorneys, and presentations to the Members.

#### Kentucky Municipal Power Agency (KMPA)

**Project Manager.** Mr. Stein has directed the development of strategic organizational issues relating to the power supply contractual relationship between KMPA and the Member utilities. He was instrumental in contract drafting of a power sales agreement for ownership in a jointly owned coal resource and is expected to be involved in other agreements required to implement this new organization including the disposition and accounting of energy resources among the members.

**MEAG Power**

**Project Manager.** Mr. Stein was responsible for directing the initial discussions and studies that ultimately lead to the formation of a municipal pooling arrangement in the southeast. The initial discussions and studies were undertaken by representatives of the Alabama Municipal Energy Authority, JEA, MEAG Power, Santee Cooper and City of Tallahassee. As a result of initial meetings and discussions among the utilities concerning potential benefits of sharing ideas, the utilities agreed to initiate a high level study concerning the potential mutual benefits of joint planning of future resources and a joint energy dispatch arrangement. The analysis included a preliminary energy dispatch for the load and resources for each of the utilities individually and a preliminary energy dispatch for the load and resources for the 5 utilities together for the Study Period. The projected total fuel cost summed together for the 5 utilities individually was compared to the projected fuel cost for the dispatch for the load and resources for the 5 utilities together. This preliminary analysis show projected lower fuel costs for the 5 utilities together compared to the 5 utilities individually and potential benefits associated with a delay in certain of the planned generation resources when the capacity resources were used to meet the composite peak demand and capacity reserves for the 5 utilities.

**City of Tallahassee, Florida**

**Project Manager.** Mr. Stein has directed the development of various power supply studies and analyses that have considered purchasing power alternatives, ownership interest in jointly-owned units, construction of new power supply resources operating on fossil fuels, refurbishment of existing facilities considering gas and wood fuels, cogeneration facilities and associated transmission facilities. One of the projects included assisting the City in seeking DOE funding for a proposed clean coal technology CFB boiler. This work has included the participation in contract review, negotiations, and discussions with electric utilities, developers and vendors, and project coordination with other technical experts and attorneys.

**City of Starke, Florida**

**Project Manager.** Mr. Stein was responsible for directing the preparation of a report considering the installation of a parallel-operated interconnection between the City and Florida Power & Light Co. The study considered an analysis of continued isolated operation vs. parallel operation, the power supply arrangement and reliability criteria under each method of operation, the cost of power under each arrangement, and a description of potential alternative facility arrangements under parallel operation. He also assisted in negotiating an interchange agreement between the City and Florida Power and Light Co.

**Alabama Municipal Electric Authority**

**Project Manager.** Mr. Stein was responsible for directing the studies and analysis that lead to the initial power supply arrangement undertaken in the formation of AMEA. The studies included analysis of the accounting and disposition among the 11 participants of the various capacity and energy resources. The initial and subsequent studies and reports have considered alternative power arrangements, including unit and system purchases, prepaid purchased power arrangements, joint ownership in fossil and nuclear generation facilities and transmission facilities, hydroelectric facilities, peak power generation facilities, and peanut hull fueled generation facilities. This work has included the participation in discussions and negotiations with electric utilities and developers and project coordination with other technical experts. He also assisted in negotiating a contemporary partial requirements agreement that reflects the "Peaker Method" for cost allocation and rate design and includes charges for load regulation, transmission interface, control center services, unit commitment services, reactive control, transactional evaluation and back-up of reserves.

#### Municipal Electric Authority of Georgia (MEAG)

**Project Manager.** R. W. Beck conducted a preliminary power supply analysis prior to proceeding with a reverse RFP. MEAG Power's existing coal fuel resources were allowed to compete with new combined cycle, combustion turbine and base, intermediate and peaking partial requirements power to obtain a least cost resource mix over the 20-year study period. Both fixed (including debt service on existing units) and variable costs were considered. The computer software model IRP Manager was used in the analysis. The study revealed that an optional mix of resources would include a short-term sale of certain of MEAG Power's existing coal fuel resources.

#### City of St. Cloud, Florida

**Project Manager.** Mr. Stein was responsible for directing the analysis and preparation of a report to consider alternative power supply offers and arrangements to meet the City's future requirements. The studies included a load forecast, review of transmission interface and diesel station capability, screening alternatives including purchases from others, ownership in diesel, combustion turbine, combined cycle and coal steam facilities, and preparing annual and cumulative and cumulative present worth projected power costs under the lowest projected power supply alternative. The study was concluded with a presentation of the results to the City Council, staff and members of a citizens committee.

#### Bahamas Electricity Corporation

**Assistant Project Manager.** Mr. Stein was part of the project team that conducted a long-range power supply study for the Bahamas Electricity Corp. This study included the preparation of a load forecast, financial model, identifying power supply alternatives, an operation and maintenance review of existing facilities and the development of a long-range plan. Certain portions of the analysis were prepared both in current and nominal dollars.

## Procurement Services/Cogeneration

### RFP and Procurement Services

#### City of New Smyrna Beach, Florida

**Project Manager.** R. W. Beck was selected by the Utilities Commission, City of New Smyrna Beach (UNCSB) to assist with the issuance of a RFP for renewable capacity and energy resources. R. W. Beck performed the following services:

- Helped clarify/establish the purpose and intent of the RFP
- Identified how the proposed resources fit with the UCNSB other power supply resources in supplying the total system net energy requirements
- Developed the RFP
- Answered bidder questions
- Conducted the pre-bid meeting
- Evaluated bids

### Request for Resource Proposals

#### City of Front Royal, Virginia

**Co-Project Manager.** R. W. Beck assisted in soliciting all-requirements power supply arrangement to replace their existing contract for all requirements power. R. W. Beck provided RFP process services, including RFP development; and a review of proposals. The work involved identifying, contacting and informing interested bidders about the RFP process.

## Request for Resource Proposals

### City of Vineland, NJ

**Project Manager.** R. W. Beck assisted the Vineland Municipal Electric Utility (VMEU) in conducting a solicitation for electric supply-side resources to meet its future power supply needs. VMEU was interested in proposals for resources located in the City. VMEU requested R. W. Beck to assist in directing the RFP process, prepare and post the RFP and addendum on the R. W. Beck web site, identify potential proposers, conduct the pre-bid meeting, assist in responding to proposer's questions, and prepare the RFP evaluation process. The process was coordinated with the City purchasing department and legal representatives. The evaluation involved a process to evaluate both price and non-price issues. R. W. Beck prepared a status report to summarize the stage one and two screening.

## Request for Power

### Florida Municipal Power Agency, JEA, Reedy Creek Improvement District and the City of Tallahassee, Florida

**Project Manager.** R. W. Beck assisted the four Utilities in conducting a solicitation for alternatives to a 750 MW solid fuels resource. R. W. Beck assisted in obtaining a common understanding and description of the individual Utilities' goals and objectives, preparing the RFP, identified a list of the potential responded, conducted the mandatory pre-bid meeting and performed an evaluation of the proposals.

## Request for Resource Proposals

### Idaho Power Company (Idaho Power)

**Project Manager.** R. W. Beck assisted Idaho Power in conducting a solicitation for electric supply-side resources to meet its future power supply needs. Idaho Power requested R. W. Beck serve as an independent third party advisor since Idaho Power had not previously issued a power supply RFP. In this role, R. W. Beck assisted in directing the RFP process, preparing the RFP and an evaluation manual. The evaluation process involved a process to evaluate both price and non-price issues. We also assisted in responding to questions from bidders, attending meetings with the public utilities commission and bidders, performing an evaluation of the proposals and helping to develop a short-list.

## Request for Resource Proposals

### Confidential Canadian Utility

**Project Manager.** R. W. Beck assisted a confidential Canadian utility (Utility) in its work with regulators to establish a methodology for a solicitation for electric supply-side resources to meet its future power supply needs. The Utility requested R. W. Beck serve the Utility as an independent third party advisor since the Utility had not previously issued a power supply RFP. In this role, R. W. Beck assisted in the review of a process that includes the preparation of a RFP, a pre-bid meeting and an evaluation process. The process will provide procedures that will fairly and impartially evaluate bids and options. The evaluation process is designed to considered both price and non-price issues.

## Request for Proposals for Power Supply

### Cities of North Little Rock and Benton, Arkansas

**Project Manager.** R. W. Beck was requested to provide the City of North Little Rock, Arkansas assistance with conducting a RFP process to obtain a new power supply arrangement when its existing contract for power supply terminates in 2002. The City stated that it selected R. W. Beck because of our reputation in power supply, experience with RFPs and reputation with municipal utilities. Implementing the new arrangement required the new supplier to file for network transmission service under the Entergy Open Access Transmission Tariff as the City's agent and dynamically schedule the City's hourly load into a new control area.

## Resource Situation Analysis

### Old Dominion Electric Cooperative

**Project Manager.** Mr. Stein, together with other Senior Consultants of R. W. Beck, prepared and conducted a one-day power supply situation analysis for Old Dominion. The situation analysis allowed an independent review and discussion of Old Dominion's current in-house derived plan for determining whether or not to proceed to build additional generation resources.

## International Power Production Seminar

### Multilateral Funding Organization, Nairobi and Kenya, Africa

**Speaker/Presenter.** R. W. Beck was retained by a multilateral funding organization to participate in an intensive workshop in Nairobi, Kenya, on independent power, and conducting a request-for-proposal process for increased capacity.

Representatives from Ethiopia, Kenya, Tanzania and Uganda attended the seminar, which was presented by a group of eight people from the United States and Great Britain. An engineer, an economist and an attorney from the funding organization made presentations, as did an attorney from Ashorst Morris Crisp and a financial advisor from Chemical Bank. The other presenters were two Hunton & Williams attorneys and R. W. Beck, which focused on the technical aspects.

Mr. Stein's presentation, "Acquiring Private Power Projects," covered competitive bidding, direct negotiations and competitive negotiations.

## Request for Proposal Evaluation

### PUD Number 1 of Snohomish County, Washington

**Project Manager.** Mr. Stein provided a two-day consulting assignment to the District for preparing an evaluation process to rank responses to its RFP for Power Supply Resources. The evaluation process was designed to consider both price and non-price considerations.

## All Requirements Power Supply Procurement

### Kissimmee Utility Authority (KUA)

**Project Manager.** R. W. Beck was responsible for assisting KUA with the planning, writing and evaluation of a power supply RFP for all requirements power supply services of a period of five years. The firm established the RFP on an Internet Web site that allowed bidders to: (1) review the RFP, (2) download the RFP, (3) identify themselves as a bidder, and 4) review addendum. Placing the RFP on the Web site reduced the amount of time and cost to KUA associated with distributing the RFP and addendum.

## All Requirements Power Supply Procurement

### City of Hagerstown, Maryland and the Towns of Front Royal, Thurmont and Williamsburg

**Project Manager.** R. W. Beck was responsible for assisting the utilities on two occasions with the planning, writing and evaluation of a power supply RFP for all requirements power supply services of a period of five years. The firm established the RFP on an Internet Web site that allowed bidders to: (1) review the RFP, (2) download the RFP, (3) identify themselves as a bidder, and (4) review addendum.

Placing the RFP on the Web site reduced the amount of time and cost to the utilities associated with distributing the RFP and addendum.

## Cogeneration Feasibility Study

### City of Tallahassee, Florida

**Project Manager.** This study presented the projected impact on both the City's electric and gas utilities associated with the City's largest electric and gas customer proceeding with the construction of a cogeneration facility to provide a portion or all of its steam and electric requirements. The study included an economic comparison of the customer's project costs assuming the City continued to serve its requirements versus the change. Alternative gas supply arrangements for both the electric and gas systems were analyzed. A comparison was also presented to show the ranking of the three bidders that submitted cogeneration facilities proposals to the customer.

## RFP Evaluation

### Orlando Utilities Commission (OUC), Florida

**Project Coordinator.** Consulting services were provided with respect to the issuance of a RFP for a cogeneration project, the format of a pre-bid conference with potential respondents, the preparation of an evaluation manual to evaluate responses to the RFP, the evaluation of three responses to the RFP, and the testimony before the Florida Public Service Commission concerning the evaluation. The responses to the RFPs were evaluated, ranked and compared to the OUC power supply alternative of constructing a second 400 MW coal-fired unit at an existing power plant station. The evaluation showed that it was more economical to proceed with the second 400 MW unit.

## RFP Evaluation

### City of St. Cloud, Florida

**Project Manager.** Consulting services were provided with respect to assisting the City with a RFP process for a long-range purchased power arrangement. The services included: (1) preparing the RFP, (2) preparing the format of and facilitating the pre-bid conference with potential respondents, (3) the preparation of an evaluation manual to evaluate responses to the RFP, (4) the evaluation and ranking of the responses to the RFP, and (5) the negotiation with the selected respondent(s).

## Procurement Services

### City of Tallahassee, Florida

**Co-Project Manager.** R. W. Beck assisted the City in the development of a standard offer contract, interconnection agreement and standards, and transmission agreement for potential cogenerators in accordance with the Florida Public Service Commission cogeneration rules and regulations. The standard offer contracts provide terms and conditions for the purchase of avoided energy, avoided capacity and energy, and the sale of back-up capacity and energy. As part of the analysis, the City's short- and long-run avoided cost and avoided unit were identified and analyzed.

## RFP Evaluation

### Alabama Municipal Electric Authority

**Project Manager.** Consulting services were provided with respect to writing a RFP, assisting in conducting the pre-bid conference, evaluating the responses and contract negotiations. The evaluation process included a multi-staged screening analysis considering the respondent's assumptions, common assumptions, technical and contractual aspects of each proposal, transmission and back-up services, as well as the Authority's other contractual arrangements. Similar services were provided in 1990, 1993 and 1997.

## Cogeneration Feasibility Study

**Prudential Power Funding Associates (Prudential)**

**Project Manager.** R. W. Beck was employed to conduct an independent engineering review for Prudential to evaluate the technical, contractual and financial merits of a cogeneration facility in Florida. The task involved the preparation of projected operating results over the life of a proposed cogeneration facility. It also involved discussions with the underwriters, review of the electric and thermal power sales contracts and preparation of projected revenues and expenses over a fifteen-year period under basic assumptions and sensitivity case analysis.

## Demand- and Supply-Side RFP Process

**Golden Spread Electric Cooperative, Inc.**

**Project Manager.** Consulting services were provided with respect to assisting Golden Spread with the preparation of a demand- and supply-side RFP for peaking projects. The firm was also be responsible for distributing copies of the RFP upon receipt of a payment, answering questions from prospective respondents, assisting with the pre-bid conference, conducting an independent evaluation, negotiations and providing testimony before the Public Utility Commission of Texas (PUCT). The PUCT's final order stated that the RFP evaluation criteria were reasonable and was fairly and consistently applied to all bidders.

## RFP Evaluation Process

**City of Tallahassee, Florida**

**Project Manager.** R. W. Beck provided advice and counsel as requested with respect to the City RFP process. Such services included preparing the evaluation process, and periodic high level reviews of the evaluation process.

## RFP Process

**Florida Municipal Power Agency**

**Project Manager.** R. W. Beck was responsible for assisting FMPA in two separate RFPs. The firm also assisted in identifying entities to notify about the RFPs and establishing the format for the pre-bid conference. R. W. Beck was requested to attend the pre-bid conference, assist in the design of a multi-staged evaluation process and assist in the evaluation of proposals submitted to FMPA. The firm established the RFPs on an Internet Web site that allowed bidders to: (1) review the RFPs, (2) download the RFPs, (3) identify themselves as a bidder, and (4) review addendum. Similar services were provided in 1996 and 1997. Placing the RFPs on the Web site reduced the amount of time and cost associated with distributing the RFPs and addendum.

## Demand Side Management

**City of Tallahassee, Florida**

**Project Manager.** This preliminary survey of commercial conservation program study included an identification, description, and status of other utilities' commercial conservation programs. A preliminary assessment of potential customer acceptance, limitations and constraints for certain programs was also provided. The study included a presentation of a preliminary economic screening analysis (the net of avoided and program costs) of various conservation programs and identified a potential work plan and projected costs and manpower requirements for implementing a lighting retrofit, new building and cool storage commercial conservation programs as its initial goals.

**City of Tallahassee, Florida**

**Co-Project Manager.** This alternative residential load management electric rate study included the development of alternative rates for residential load management service based on Tallahassee's cost and approved rates for similar service provided by other Florida utilities. The rates were structured to provide an incentive to encourage customer participation in Tallahassee's load management program. Mr. Stein was responsible for preparing the projected avoided cost and benefits associated with the implementation of a load management system.

**Alabama Municipal Electric Authority**

**Project Manager.** This preliminary analysis of load factor improvement study presented an evaluation of the potential benefits or avoided costs associated with load factor improvement (reducing peak demand). A survey and discussion of alternative programs used by other electric utilities for load factor improvement was also provided. The programs ranged from customer education to direct load control of customer appliances. The projected costs and benefits for implementing residential load management, commercial and industrial programs were provided.

**Alabama Municipal Electric Authority**

**Co-Project Manager.** This preliminary engineering study of load management system alternatives study consisted of technical and economic analyses of implementing a load management system with central control in Montgomery and local load control at each of 11 individual member cities located in South and Central Alabama. The study reviewed both power-line carrier and radio based systems, examining the economics over the life of the project. Both avoided costs and program implementation costs were considered. Mr. Stein was responsible for directing the cost/benefit analysis portion of the study.

## Expert Testimony

**Golden Spread Electric Cooperative, Inc., Texas**

**Expert Witness.** Mr. Stein prepared written testimony before the Public Utility Commission of Texas with regard to a consulting assignment with Golden Spread to serve as the Independent Evaluator in a RFP process.

**City of Tallahassee, Florida**

**Expert Witness.** Mr. Stein prepared written testimony before the Florida Public Service Commission in: (1) a territorial dispute with regard to projected power supply arrangements for both parties and (2) a needs hearing concerning a 230 kV transmission line interconnection between the City and Georgia Power Co.

**Alabama Municipal Electric Authority**

**Expert Witness.** Mr. Stein prepared written testimony before the Federal Energy Regulatory Commission concerning the cost related treatment and use of capacitors in planning a bulk power supply system.

**City of Starke, Florida**

**Expert Witness.** Mr. Stein served as an expert witness before a Florida circuit court in a bond validation hearing with respect to the economics of constructing and operating a parallel operated interconnection between the City and Florida Power & Light Company.

## Rates

### City of Starke, Florida

**Project Manager.** Mr. Stein was responsible for directing the preparation of a new monthly energy cost adjustment factor for its electric rates for recovering the changes in the monthly costs for fuel and purchased power. A similar rate was also prepared for the City's gas utility system.

### City of Tallahassee, Florida

**Project Manager.** Mr. Stein was responsible for directing the development of and periodic update of cost support schedules used to calculate rates for wholesale interchange transactions between the City and other generating electric utilities.

### City of Dothan, Alabama

**Co-Project Manager.** Mr. Stein was responsible for directing the preparation of an interruptible electric rate for industrial customers. This rate was designed to take into consideration the City's existing large power rate and the City's cost of purchased power.

## Consulting Engineer's Report - Financing

### City of Tallahassee, Florida

**Co-Project Coordinator.** Mr. Stein was responsible for preparing the Consulting Engineer's report that was used by the City to issue approximately \$93 million in electric utility revenue bonds. The report included a description of the system, purpose of the issuance and historical and projected operating results showing debt service coverage. The work also included the development of a new bond resolution.

### City of Starke, Florida

**Project Coordinator.** Mr. Stein was responsible for preparing the Consulting Engineer's report that was used by the City to issue approximately \$3 million in electric utility revenue bonds. The report included a description of the system, purpose of the issuance and historical and projected operating results showing debt service coverage.

### Alabama Municipal Electric Authority

**Project Coordinator.** Mr. Stein was responsible for preparing Consulting Engineer's reports or financing documents that were used by the Authority to issue approximately \$350 million in electric utility revenue bonds. The reports included a description of the system, purpose of the issuance and historical and projected operating results showing debt service coverage. Bonds were issued to fund the prepayment for purchased power arrangements, load management facilities, rate stabilization, and peaking power facilities.

## Periodic Reports

### Alabama Municipal Electric Authority

**Project Manager.** Mr. Stein directed the preparation of the first two quinquennial (five-year) reports required pursuant to the Bond Resolution. The report included a description of the Authority's management, projects undertaken by the Authority, and a comparison of actual versus budgeted revenues and expenses.

**City of Tallahassee, Florida**

Mr. Stein was responsible for preparing a description of the existing power supply arrangements and power supply alternatives that were under consideration by the City to meet its projected requirements for the City's biennial report.

# Record of Power Supply Request for Proposals

Steven Stein, P.E.

| Year | Client | Summary of Services |
|---|---|---|
| 1985 | Orlando Utilities Commission (FL) | Base Load Resources. |
| 1989 | Alabama Municipal Electric Authority | Prepared the RFP, conducted evaluations of proposals and helped with contract negotiations for a "Base Load" purchase. |
| October 1991 | Alabama Municipal Electric Authority | Prepared the RFP, conducted evaluations of proposals and helped with contract negotiations for "Peaking" purchase. |
| April 26, 1993 | City of St. Cloud (FL) | Prepared the RFP, conducted evaluations of proposals and conducted contract negotiations for an All Requirement Purchase. |
| 1994 | Snohomish County Public Utility District (WA) | Training on Conducting an RFP Process. |
| August 31, 1995 | City of Tallahassee (FL) | Helped prepare the RFP and helped conduct evaluations. |
| 1996 | City of St. Cloud (FL) | Prepared the RFP, conducted evaluations of proposals and conducted contract negotiations for an All Requirements Purchase with sale of excess capacity. |
| February 1996 | World Bank – East Africa | Conducted Hand-On Training on Conducting an RFP. |
| March 1, 1996 | Alabama Municipal Electric Authority | Prepared the RFP, conducted evaluations of proposals and helped with contract negotiations. |
| May 28, 1997 | Kissimmee Utilities Authority (FL) | Capacity and Energy Purchases. |
| May 28, 1997 | Florida Municipal Power Agency | Capacity and Energy Purchases. |
| May 28, 1997 | Florida Municipal Power Agency | Capacity and Energy Purchases. |
| May 24, 2000 | Orlando Utilities Commission (FL)/Florida Municipal Power Agency/Kissimmee Utilities Authority (FL) | 750 MW Physically Firm Dispatchable Capacity and Energy. |
| July 17,1997 | City of Hagerstown (MD) and Towns of Front Royal (VA), Thurmont (MD) and Williamsport (MD) | Prepared the RFP, conducted evaluations of proposals and conducted contract negotiations for All Requirements Purchases in the PJM market. |
| July 17, 1997 | Golden Spread Electric Cooperative (TX) | Helped prepared the RFP, conducted evaluations of proposals and helped with contract negotiations for a 400 MW GT Project that was revised to consider a CC Project. |
| August 4, 2000 | Idaho Power Company | Helped prepare the RFP, conducted an independent evaluation of proposals concerning a Supply Side CC Resource. |

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## Record of Power Supply Request for Proposals

Steven Stein, P.E.

| Year | Client | Summary of Services |
|---|---|---|
| February 2001 | Confidential Client (Canada) | Assisted Client Develop RFP Procedures for Approval by the Energy Board, Code of Ethics and Procedure. |
| April 27, 2001 | North Little Rock & Benton (AR) | Prepared the RFP, conducted evaluations of proposals and conducted contract negotiations for All and Partial Requirements Purchases. |
| Fall 2001 | Confidential Client (OK) | Prepared the RFP and conducted evaluations of proposals concerning a Unit Power Purchases. |
| March 1, 2002 | City of Hagerstown (MD) and Towns of Front Royal (VA), Thurmont (MD) and Williamsport (MD) | Prepared the RFP, conducted evaluations of proposals and conducted contract negotiations for All Requirements Purchases in the PJM market. |
| March 2002 | Confidential Client (Canada) | Assist with Power Supply RFP (Combined Cycle). |
| May 13, 2002 | The Energy Authority/Nebraska Public Power District | Sale of Energy and Capacity (reverse RFP). |
| August 23, 2002 | City of Columbia (MO) | Prepared the RFP, conducted evaluations of proposals and conducted contract negotiations for a Purchase of Capacity and Energy (System) in the MISO market. |
| February 17, 2003 | Conway Corporation (AR) | Prepared the RFP and conducted evaluations of proposals for a Partial Requirements Capacity and Energy Arrangement. |
| April 2003 | Confidential Client (Canada) | Assist with Draft Language to Implement Cogeneration Rules for an RFP Process. |
| February 24, 2003 | Idaho Power Company | Helped prepared the RFP, helped with evaluations of proposals and helped with contract negotiations for a 85 - 200 MW of Capacity and Energy during June, July, August, November and December. |
| December 2003 | Winter Park (FL) | Reviewed RFP and Process for All Requirements Power. |
| July 6, 2004 | 7 Arkansas Utilities | Prepared the RFP, conducted evaluations of proposals and conducted contract negotiations for All-Requirements, Partial Requirements, Block Power, and/or Control Area, Transmission & Ancillary Services. |

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Grow/20

**Record of Power Supply Request for Proposals**
Steven Stein, P.E.

| Year | Client | Summary of Services |
|---|---|---|
| June 7 , 2005 | City of Hagerstown (MD) and Towns of Front Royal (VA), Thurmont (MD) and Williamsport (MD)` | Prepared the RFP, conducted evaluations of proposals and conducted contract negotiations for All Requirements Purchases in the PJM market. An implementation analysis involved the evaluation of auction revenue rights (AAR) and firm transmission rights (FTR) associated with the prior and new provider under the contract. |
| November 2005 | Florida Municipal Power Agency, Jacksonville Electric Authority (FL), Reedy Creek Improvement District (FL) & City of Tallahassee (FL) | Prepared the RFP and conducted evaluations for the Utilities seeking alternatives to a 750 MW solid fuels resource. |
| Summer 2005 | Florida Municipal Power Agency | Peaking Power RFP. |
| September 2005 | Cities of North Little Rock and Benton (AR) | All and Partial Requirements Purchases. |
| December 2005 | City of Front Royal (VA) | Prepared the RFP and conducted evaluations of proposals for All Requirements Purchases in the PJM market. |
| March 2006 | Central Minnesota Municipal Power Agency (CMMPA) | Base and intermediate load partial requirements RFP for 12 members of CMMPA in the MISO market. |
| April 2006 | City of Mt. Dora (FL) | Prepared the RFP, conducted evaluations of proposals and conducted contract negotiations for an All Requirements Purchase. |
| June 2007 | Utilities Commission, City of New Smyrna Beach (FL) | Prepared the RFP, conducted the Pre-Bid Meeting and will conduct evaluations of proposals and contract negotiations for Renewable Resources. |
| June 2007 | Florida Municipal Power Agency | Prepared the RFP, conducted the Pre-Bid Meeting and will conduct evaluations of proposals and contract negotiations for Renewable Resources. |
| June 2007 | Florida Municipal Power Agency | Prepared the RFP and assisted in conducting the Pre-Bid Meeting, all for base load and intermediate resources. |
| February 2008 | Vineland Municipal Electric Utility (NJ) | Prepared and posted the RFP, assisted in conducting the Pre-Bid Meeting, responding to proposer's questions, prepared addenda, prepared an evaluation process, and prepared a stage one and two screening report. |

**Record of Power Supply Request for Proposals**
Steven Stein, P.E.

| Year | Client | Summary of Services |
|---|---|---|
| May 2008 | Idaho Power Company | Acting as the independent engineer, assisted in the preparation of the RFP for a 2012 Baseload Generation resource, attend and helped write the Pre-Bid Meeting presentation, assisted in responding to respondent's questions and assisted in the evaluation of proposals. |
| January 2008 | City of Osceola (AR) | Assisted in the preparation of an RFP for all requirements power. |
| October 2008 | Conway Corporation (AR) and West Memphis (AR) | Assisting the Utilities with an RFP process for all requirement power. |

# BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

## IDAHO POWER COMPANY

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Exhibit Accompanying Testimony of Lisa A. Grow
Langley Gulch Power Plant Cost Summary

March 9, 2012

## Idaho Power Company
## Langley Gulch Power Plant Cost Summary

| | January $s spent to date | Remaining $'s to Spend | Total Spend through June, 2012 | Total expected project spend | Binding Pre-Approved Amount | Company's Original Component Summary |
|---|---|---|---|---|---|---|
| Gas Turbine | 54,493,369 | 1,600,470 | 56,093,839 | 56,243,839 | 56,281,662 | 56,281,662 |
| Steam Turbine | 34,972,736 | 739,623 | 35,712,359 | 35,862,359 | 35,710,905 | 35,710,905 |
| EPC Contract | 203,287,526 | 10,058,927 | 213,346,453 | 215,723,168 | 221,421,431 | 221,421,431 |
| Commitment Estimate Contingency | - | - | - | - | - | 6,800,686 |
| Site Procurement | 1,957,322 | 42,678 | 2,000,000 | 2,000,000 | 1,950,000 | 2,000,000 |
| Water Rights | 2,083,419 | - | 2,083,419 | 2,083,419 | 2,081,269 | 2,200,000 |
| NEPA Permitting | 214,431 | - | 214,431 | 214,431 | 150,000 | 150,000 |
| Air Permitting | 350,547 | 14,453 | 365,000 | 390,000 | 320,000 | 320,000 |
| Water Line Construction | 4,560,042 | 19,958 | 4,580,000 | 4,580,000 | 4,425,000 | 8,850,000 |
| Gas Line Construction | 3,166,087 | 3,913 | 3,170,000 | 3,170,000 | 1,550,000 | 3,100,000 |
| Miscellaneous Equipment (Idaho Power supplied) | 1,668,066 | 902,566 | 2,570,632 | 2,570,632 | 331,150 | 662,300 |
| Capitalized Property Taxes | 953,926 | 490,505 | 1,444,431 | 1,444,431 | 2,881,277 | 2,881,277 |
| Idaho Power Engineering and Oversight | 2,408,918 | 330,000 | 2,738,918 | 2,820,000 | 1,900,000 | 3,800,000 |
| RFP Pricing components (includes start up fuels) | 399,303 | 4,674,996 | 5,074,298 | 5,574,298 | 500,000 | 2,250,000 |
| Transmission | 17,746,432 | 4,423,628 | 22,170,060 | 22,170,060 | 17,856,400 | 31,679,100 |
| AFUDC | 33,624,957 | 12,944,980 | 46,569,937 | 46,569,937 | 49,259,379 | 49,259,378 |
| Totals | **361,887,082** * | **36,246,696** | **398,133,778** | **401,416,575** | **396,618,473** ** | **427,366,739** *** |

* Reported on Accrual based accounting
** Binding Pre-approved Amount as approved by Order No.30892 (Staff's Revised Confidential Exhibit No. 109)
*** Company's Originally Filed Commitment Estimate

Idaho Power/205
Grow/1