Office of the Secretary
Service Date
September 1, 2009

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** **ORDER NO. 30892**

On March 6, 2009, Idaho Power Company (Idaho Power; Company) filed an Application with the Idaho Public Utilities Commission (Commission; IPUC) for a Certificate of Public Convenience and Necessity (Certificate; CPCN) authorizing construction of the Langley Gulch Power Plant (Project) and inclusion of the Project in the Company's rate base. *Idaho Code* § 61-526, -528; RP 112. An electrical corporation is prohibited from beginning the construction of a generating plant without having first obtained from the Commission a certificate that the present or future public convenience and necessity require or will require such construction. *Idaho Code* § 61-526. The Company further requests that the Commission include in its Order issuing a Certificate cost recovery and ratemaking assurances. *Idaho Code* § 61-541.

On March 19, 2009, the Commission issued a Notice of Application, Intervention Deadline and Prehearing Conference. Intervention was granted to the Industrial Customers of Idaho Power (ICIP); Invenergy Thermal Development LLC; Idaho Irrigation Pumpers Association, Inc. (IIPA); Snake River Alliance (SRA); and Idaho Conservation League (ICL). Following the April 15, 2009 prehearing conference Invenergy Thermal Development LLC withdrew and the following additional parties were admitted as intervenors: Northwest & Intermountain Power Producers Coalition (NIPPC) and Community Action Partnership Association of Idaho (CAPAI). An evidentiary and technical hearing was held in Boise on July 14-16, 2009. A public hearing was held the evening of July 14. The deadline for filing written comments was July 24. The deadline for post-hearing filings by the parties was July 31, 2009.

The Commission in this Order grants a Certificate of Convenience and Necessity authorizing the construction of Langley Gulch and provides related cost recovery and ratemaking assurances. *Idaho Code* § 61-541. We deny Intervenors' Motion for Stay and grant intervenor funding awards to the Community Action Partnership Association of Idaho, the Idaho Conservation League and the Idaho Irrigation Pumpers Association, Inc. *Idaho Code* § 61-617A.

APPLICATION

A. The Langley Gulch Power Plant

Idaho Power requests a CPCN and authority to construct, own, operate and maintain the Langley Gulch Power Plant. The Project is a natural gas-fired combined-cycle combustion turbine (CCCT) generating plant with a nameplate capacity of approximately 330 MW. Gale, Tr. pp. 147, 148. The Company proposes to construct the Project 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. Porter, Tr. p. 439. The Project's power plant consists of a combustion turbine (Siemens SGT-5000F) and a steam turbine (Siemens SST-900). The plant is designed to be water-cooled and equipped with state-of-the-art emission control equipment. Sterling, Tr. p. 1071.

B. Future Necessity and 2006 Integrated Resource Plan

The Project is a baseload generating resource of the size and type identified as the preferred resource in the Company's June 2008 update to its 2006 Integrated Resource Plan (IRP). Bokenkamp, Tr. p. 262; Exh. 101. The Project was selected as a result of a competitive process (Request for Proposals or RFP) in which the Company solicited proposals from independent power supply developers. The proposals were compared to each other and to a utility-owned and operated CCCT (Benchmark Resource). The Langley Gulch project is the Benchmark Resource and is scheduled to be available to meet peak loads in 2012.

C. Capital Cost Commitment Estimate

Idaho Power's Commitment Estimate for the Project is $427,400,000 and includes the power plant and two related transmission projects (2.5 miles Ontario-Caldwell; 18 miles Caldwell-Willis). On a 20-year net present value (NPV) basis the Project is estimated to have a revenue requirement impact approximately $95 million lower than the next least expensive proposal in the Company's RFP process. Smith, Tr. p. 22.

The Company commits to procure and construct the Project for an amount that will not exceed the Commitment Estimate. Idaho Power requests that amounts incurred in excess of the Commitment Estimate be subject to a "soft cap"; that is, excess costs could be included in rates only if the Commission agrees the additional amounts expended are prudent and that it is fair, just and reasonable to include them in rates.

The Company commits to provide the Commission with periodic percentage of completion reports and cost expenditure reports during the construction phase of the Project. The final report on the Project will compare the actual completed cost to the Commitment Estimate.

D. Fuel Cost

A major component of the operating cost of a combined-cycle combustion turbine generating plant is the cost of natural gas fuel. The Company states that it currently owns, or will acquire, firm fuel transportation rights that can be utilized by the Project. As part of its Application, the Company is requesting that the Commission's Order issuing the Certificate of Public Convenience and Necessity also authorize Idaho Power to recover the Project's prudently incurred costs for fuel, fuel storage and fuel transportation through the Company's Power Cost Adjustment (PCA) mechanism.

E. Cost Recovery and Ratemaking Assurances

In its Application for a Certificate, Idaho Power requested that the Commission include in its Order authority for the Company to utilize either or both of two alternative ratemaking treatments that will put the Company in the best position to finance this project. The first requested ratemaking treatment would allow the Company to annually collect construction work in progress (CWIP) in its rates for all, or a portion of, the construction expenditures the Company incurs as it moves forward with construction of the Project (*Idaho Code* § 61-502a). Alternatively, the Company requests that the Commission apply specific ratemaking treatment that the Company can rely upon when the Project is completed and providing service to customers. The second alternative ratemaking treatment proposal requested by the Company was pursuant to the construction cost recovery legislation then being discussed by the 2009 Idaho Legislature (Senate Bill 1123). The Legislature subsequently passed Senate Bill 1123 and the Governor signed the Bill into law as *Idaho Code* § 61-541 – Binding Ratemaking Treatment.

Until the Commission issues a Certificate with pre-approved (binding) ratemaking treatment and related provisions *(Idaho Code* § 61-541), the Company states it cannot prudently proceed with the Project. As a result, the commercial operation date of the Project is directly related to the issuance of a Certificate, including the necessary cost-recovery ratemaking commitments. To the extent the Commission can expedite its review of the Application, the

Company contends that it will benefit customers and system reliability. The Company requests a Commission Order by September 1, 2009.

JOINT MOTION FOR STAY

On May 29, 2009, a Joint Motion to Stay Proceedings in Case No. IPC-E-09-03 for at least 10 months was filed by the Industrial Customers of Idaho Power, Idaho Irrigation Pumpers Association, Snake River Alliance, Idaho Conservation League, and Northwest & Intermountain Power Producers Coalition (collectively Movants).

The Movants contend that significant and unforeseen events have taken place since Idaho Power initially filed its Application. Any single one of these events, they contend, would be sufficient to cause reasonable persons to seek to slow down the Company's forced march to seek Commission action on its request for a Certificate. They further contend that when taken in concert, the cumulative effect of the following events makes a stay of this proceeding critical. The events cited by the Movants are the following:

- Pursuant to a shareholder resolution at a recent meeting of Idaho Power stockholders, Company management has committed to develop a greenhouse gas reduction strategy report by September 30, 2009.

- Pursuant to Idaho Power Petition, the filing date for the Company's 2009 Integrated Resource Plan was extended from June 2009 to December 31, 2009. Case No. IPC-E-09-13, Order No. 30815.

- Authorized recovery of project costs under new Idaho legislation (*Idaho Code* § 61-541) makes the Commission's decision in this case one of the most far-reaching in Idaho PUC history.

- A softening of the market for gas turbines should enable the Company to renegotiate contract penalty provisions for delay.

- Idaho Power has already delayed the plant's on-line date beyond the time necessary to meet the summer load of 2012, i.e., until December 2012.

- The continued unprecedented recession will have direct impact on immediacy of need for new power plants.

- Other regional utilities (e.g., PacifiCorp) are mothballing planned expansions.

- The impacts of recent changes in Idaho Power's demand response programs have yet to be ascertained.

On June 12, 2009, Idaho Power Company filed its Answer to the Joint Motion for Stay. The Company characterizes the points raised within the Motion for Stay as a "collection of speculation, conjecture, and unfounded assumptions." Delay in a decision, the Company contends, puts the viability of the Langley Gulch project at risk. All concerns raised by the Intervenors, the Company states, fall within the umbrella of issues identified by the Commission in its April 20, 2009, Notice of Issue Identification and can be presented to the Commission in testimony and exhibits under the procedural schedule and timeline adopted for hearing and decision in this case. The Company in its Answer continues to maintain that Langley Gulch is a needed resource to provide adequate and reliable electric service to its customers. Its commitment to shareholders to provide a report on its greenhouse reduction strategy, it states, does not affect its greater obligation to provide service. Its decision to defer the filing of its 2009 IRP, it states, does not reflect uncertainty as to the need for Langley Gulch. Even with enhanced DSM program participation, the Company still forecasts substantial capacity and energy shortfalls. To stay proceedings and push the decision date beyond September 1, 2009, the Company states, will result in very real monetary consequences placing the Company at risk for cancellation fees and lost deposits totaling $25.5 million.

In its consideration of the Motion, the Commission acknowledged that there is some information that will inform the Commission's decision in this case that will not be available until after the scheduled hearing date and the proposed September 1, 2009, date for the Commission Order. However, the Commission determined that it would not allow that uncertainty to paralyze it. Order No. 30848 (June 19, 2009). The Commission found it reasonable to continue with the established scheduling and to build an informed record for decision. The Movants at their discretion were invited to renew their Motion for Stay as a preliminary matter at the beginning of hearing.

Renewed Motion

The Motion to Stay was renewed at the beginning of the technical hearing. The Commission took the Motion under advisement for discussion at a later time as requested by the Movants, and proceeded with the hearing. Tr. p. 18. In a Joint Renewed Motion and Post-Hearing Brief filed on July 31, 2009, the Community Action Partnership Association of Idaho joined the other movants. On August 11, 2009, Idaho Power filed an Answer to the Renewed Motion.

Movants in their Renewed Motion contend that the Company failed to fully comply with the Commission's December 2006 direction in Case No. IPC-E-06-09 (Evander Andrews), Order No. 30201, to "vigorously pursue all available, cost effective DSM, conservation, and pricing options that could potentially displace or defer the need for additional future peaking generation." As a consequence, Movants contend that the public has been, and continues to be, ill-served and continues to bear risks for unnecessary future supply-side investments.

Movants cite Ninth Circuit case, *Seattle Master Builders Association v. Pacific Northwest Electric Power & Conservation*, 786 F.2d 1359 (9th Cir. 1986), as providing a definition for "cost effective conservation." The Court adopted a definition of "cost-effective" conservation measures as being all such measures with a marginal cost less than the cost of the generating resource to be acquired. Movants contend the record established through public witness Exhibit 901, shows that the levelized cost estimate for a combined-cycle combustion turbine (CCCT) is $0.126/kWh. The testimony of Company witness Pengilly, Movants contend, shows that not only has the Company not implemented all conservation measures costing less than $0.126/kWh, it has yet to even compile a list of all such opportunities. Public Witness Exh. 901, pp. 10-11.

Movants contend that the Company's purchase of equipment (turbines) in advance of obtaining a Certificate is in direct violation of *Idaho Code* § 61-526 which states:

> No . . . electrical corporation . . . shall henceforth begin the construction of a plant . . . without having first obtained from the commission a certificate that the present or future public convenience and necessity require or will require such construction.

Movants contend that the Company's forecast used to justify the need for a baseload resource in 2012 stands in sharp contrast to declines in actual demand (June 2008/March 2009) and economic trends that have developed in the last year and half. The only forecast data that the Company has offered since the recession began is the May 2009 forecast and that data, Movants contend, was only updated for the Company's special contract customer load. The economy is what the economy is, they state, and is most certainly not what Idaho Power "forecast" it to be.

The Movants have not taken the position that Langley Gulch will never be needed, simply that the economy has caused a slippage in the time of that "need."

Movants contend that regulatory preapproval of the "Commitment Estimate" under *Idaho Code* § 61-541 is unnecessary. They recommend no more binding regulatory preapproval commitment than the "regulatory compact" provision previously established by the Commission when noting:

> . . . In the ordinary course of events, the Company may expect its investment . . . to be recognized in its revenue requirement barring unforeseen circumstances. . . .

Order No. 25021, p. 13 (IPC-E-91-4, Twin Falls Upgrade).

> . . . A certificate does not guarantee a utility recovery when it ignores or defies the laws of economics by continuing to invest in plants no longer necessary or prudent because demand has fallen from projections . . . because costs have escalated beyond reasonable expectation . . . because technology has changed . . . or when management, operation or construction of a project is beyond the utility's control and under the direction of others.

Id., p. 13.

> . . . The ultimate decision determining the appropriate amount of . . . investment to include in revenue requirement will, of course, be made during the course of a general rate proceeding or a tracker proceeding initiated for that purpose.

Id., pp. 13-14.

To give greater assurance, Movants contend, is not supported by the Company's load forecast, which they contend, is significantly in error.

Recommending delay, the Movants contend that the Commission should require analyses on how much of the need for additional energy or capacity could be eliminated through cost-effective efficiency and DSM expenditures and the effect of price elasticity on future demand. Movants contend that the Company's RFP process was flawed. They urge the Commission to proceed with a generic competitive bidding docket and to adopt transparent bidding guidelines.

Idaho Power Answer

In answer to the Renewed Motion to Stay, Idaho Power contends that the delay requested by Movants is not 10 months. Based on the relief requested, the delay could extend to years – i.e., review and accept the 2009 IRP; to conduct a formal proceeding to develop new generic guidelines for competitive bidding; and then to issue a new RFP. A delay of this sort, the Company contends, exposes the utility and its customers to substantial risk.

Long lead-time resources, such as Langley Gulch, the Company states, take at least three years to construct. The Company contends that it cannot wait until it absolutely positively knows what its loads will be at a point in the future before it acts. It must rely on a forecast of loads and a portfolio of resources to strike a load and resource balance that will allow it to satisfy its legal obligation to serve and to do so at the lowest reasonable cost consistent with prudent utility planning criteria.

Intervenors argue the Commission should examine whether the Company's 2009 actual loads are lower than they were in 2008 rather than focusing on the Company's forecast loads for 2012. The Company points out there are numerous reasons why actual loads in 2009 might be lower, the recession being only one. Other reasons include precipitation, temperature, commodity prices and shifting world markets for computer chips and polysilicon. The more reasonable approach, Idaho Power argues, is to assess how well the Company has done recently in forecasting its future loads. See Company Post-Hearing Response to Commission Data Request. E.g., for the entire month of July, average system load was 1865 aMW (1,387,374 MWh), which is just 24 aMW lower than predicted in the May 2009 load forecast (1,405,565); and on July 22, 2009, the hourly average system load (without the impact of demand response programs) reached 3,136 MW. Evidence presented by the Company, it contends, demonstrates a continuing need for Langley Gulch in 2012. Bokenkamp, Tr. pp. 281-282; Exh. 10.

The Intervenors recommended strategy, the Company argues, is based on the assumptions that:

1. The current recession will cause the Company's loads to remain flat for an unknown but extended period of time.

2. The Company can acquire all the resources it needs for the next few years from DSM and renewable resources.

3. The Company can continue to rely on its ability to purchase a substantial amount of power from surplus generation sellers located in the Pacific Northwest and the Desert Southwest to be delivered using non-firm transmission on the existing transmission system.

In contrast, Idaho Power contends that to provide adequate reliable service in 2012, the Company needs to immediately move to add a baseload resource located near its Treasure Valley load center.

The risk profiles of the two competing strategies, the Company contends, are asymmetrical. If the Company constructs Langley Gulch, there is a risk that in 2012 not all of the output will be needed to serve native load. This risk is mitigated by the opportunity to sell surplus energy in the wholesale market, the increased reliability Langley Gulch will provide and reducing reliance on non-firm transmission to deliver more expensive wholesale purchases.

The Company contends that, if Langley Gulch is delayed, any new large customers seeking to locate plants or facilities in Idaho Power's service territory must be advised that the Company does not have firm resources sufficient to serve their loads on a year-round basis and that future additional firm resource availability is uncertain. If the resource is delayed, the Company will be forced to continue to rely heavily on the use of non-firm transmission to serve critical summer loads and the risks associated with that will be exacerbated and the risk of reduced reliability and load curtailment will increase. Finally, if the resource is delayed and in 2012 and thereafter, the Company experiences adverse water conditions, extraordinarily high temperatures, forced outages at distant generating plants, loss of transmission capability, loop flows, or any combination of these risks, the Company contends service to customers may have to be curtailed.

Should Intervenors' request for stay be granted, the Company prepared and offered Confidential Exhibit 26 identifying an escalating scale of cancellation fees (Siemens combustion and steam turbines) associated with delay beyond September 1, 2009. Also affected by a delay would be the Company's contract for Engineering, Procurement and Construction (EPC) services with Boise Power Partners Joint Venture (consisting of Kiewit Power Engineers Company and TIC – The Industrial Company).

Commission Findings

The Commission has considered the arguments advanced by Intervenors in their Motion for Stay and for reasons set forth elsewhere in this Order finds them global in nature but unpersuasive on balance. After reviewing the established record in this case, we find that the public interest is not served by delay. Intervenors contend that we should await the Company's 2009 IRP; we should wait to see the impact of changes to the Company's demand response programs; we should wait for the Company's response to shareholders regarding greenhouse gas emissions; in lieu of a new generation resource we should require more demand-side management, energy efficiency, conservation and pricing options; and we should proceed with the generic competitive bidding docket, adopt transparent bidding guidelines and require the Company to issue a new RFP. We find the risk of reducing electric service is too great to allow the delay that is proposed.

There are parts and pieces of information that are not now known. However, based on the information presented at the hearing, we find substantial evidence to support the decision to grant the Certificate requested. To bring a baseload generation unit on-line requires a lead-time of two-and-one-half to three years and requires a resource commitment and action well in advance of projected date of need. The Company has a statutory obligation to provide electric service and, since 2004, has forecast a need for a baseload generation resource in 2012. Even with a change in the nature of the generation resource itself, and a more recent load forecast to accommodate recent economic conditions, the Company continues to forecast a June-December 2012 need. The 2012 date is now the earliest date the Company can bring a baseload resource on-line. For reasons expressed elsewhere in this Order when addressing need, the Commission's decision is that Company's resource should not be delayed and thus we deny the Motion for Stay.

HEARING

An evidentiary hearing was held on July 14-16, 2009. Pursuant to Rule 67, the parties entered into a Protective Agreement regarding the disclosure and treatment of confidential information and trade secrets. IDAPA 31.01.01.067. The following parties of record appeared:

Idaho Power Company	Barton L. Kline Lisa D. Nordstrom
Industrial Customers of Idaho Power	Peter J. Richardson
Idaho Irrigation Pumpers Association, Inc.	Eric L. Olsen
Snake River Alliance	Ken Miller
Idaho Conservation League	Betsy Bridge

Northwest & Intermountain Power Producers Coalition	Susan K. Ackerman
Community Action Partnership Association of Idaho	Brad M. Purdy
Commission Staff	Scott Woodbury

The Commission has reviewed and considered the filings of record in Case No. IPC-E-09-03 including the Application and the public and confidential transcript of proceedings. We have also reviewed the below referenced Orders, statutes and rules regarding Integrated Resource Planning, intervenor funding, Certificates of Public Convenience and Necessity, CWIP and AFUDC, and Binding Ratemaking Treatment. We address and discuss the Company's case and the positions of parties in the following section.

ISSUES AND FINDINGS

Need for Resources

The Company's Integrated Resource Plans (IRPs) are filed pursuant to a biennial requirement established in Commission Order No. 22299, Case No. U-1500-165. The IRP describes the Company's growing customer base, load growth, supply-side resources, demand-side management (DSM) and risk analyses. The IRP contains information regarding available resource options, planning period forecasts, potential resource portfolios, a 20-year resource plan, and a near-term action plan. As noted by the Company in this case, the IRP is the basis for establishing the need for acquisition of additional resources – supply-side (generators and market purchases); demand-side (energy efficiency or demand response programs); and transmission lines. Bokenkamp, Tr. p. 261.

Idaho Power traces its present need for a baseload generating resource to its 2004 IRP preferred portfolio which then identified need for a 500 MW baseload pulverized coal-fired resource in 2011. Bokenkamp, Tr. p. 261. On September 24, 2006, Idaho Power filed its 2006 IRP. In response to uncertainty surrounding potential carbon legislation, Idaho Power re-assessed its need for new resources. The Company's 2006 IRP preferred portfolio identified the following resource needs:

225 MW power purchase – McNary to Boise transmission upgrade 2012
250 MW pulverized coal-fired baseload resource – 2013
250 MW regional integrated gasification combined cycle turbine (IGCC) – 2017

Bokenkamp, Tr. p. 261.

Following its 2006 IRP, the Company took note of escalating public concerns regarding climate change, greenhouse gas emissions, and changing public perceptions regarding the acceptability of coal-fired generation resources. Faced also with the possibility of several new large industrial/commercial loads in the 2009-2012 time period and a shifting of hydro flow augmentation releases from federal dams above Brownlee that would reduce levels of hydro-generation available during peak demand summer months by 140 aMW, the Company updated its 2006 IRP. The December 2008 update revised the 250 MW pulverized coal-fired baseload resource to a natural gas-fired baseload resource located closer to its load center in southern Idaho, increased the size of the resource to 300 MW and accelerated the on-line date of the resource need from 2013 to 2012. Bokenkamp, Tr. p. 262.

In Order No. 30281 issued on March 26, 2007, the Commission found that receiving each electric utility's IRP within a narrower time frame would improve the overall planning process and assist in regional planning efforts. Exh. 27. The Commission directed Idaho Power to file a brief report containing suggestions on how its IRP may be coordinated with the IRP filings of Avista and PacifiCorp dba Rocky Mountain Power. On May 10, 2007, Idaho Power filed its Letter Report.

On May 23, 2007, the Commission directed Idaho Power to file its next full IRP no later than last business day of June 2009. The Company was also directed to provide the Commission a transitional IRP update in June 2008 addressing the progress of the Company's short-term action plan; any changes in its load forecast, existing loads, customer base and purchase power contracts; and any significant deviations from its 2006 IRP. On June 20, 2008, Idaho Power filed its 2008 IRP update.

On April 24, 2009, Idaho Power filed a Petition requesting authority to defer the filing of its 2009 IRP from June 30, 2009 to December 31, 2009 (Case No. IPC-E-09-13). The Company cited two significant changes occurring since completion of its 2008 update that made it desirable to delay the filing of its 2009 IRP: (1) a permitting delay in its proposed Boardman-Hemingway (B2H) transmission project, an identified near-term (2012) resource and (2) slowed local and national economic growth necessitating an update to its sales/load forecast. By Order No. 30815, the Commission granted the Company's Petition.

Staff contends that a new baseload generation plant is justified based on the information and analyses in the Company's 2006 IRP and 2008 IRP update, the Company's load resource balance under various water and load conditions, and transmission constraints that limit the Company's ability to import power during critical times of the year. Sterling, Tr. p. 1031; Exh. 101-105.

Staff in its analysis considered the availability to the Company of other resource alternatives, e.g., non-Company owned generation, conservation, demand response programs and transmission upgrades. Staff concluded that while such alternatives may be truly viable, they cannot be relied on exclusively and should be pursued in conjunction with and not instead of Langley Gulch. Sterling, Tr. p. 1021.

- In its 2006 IRP planning process the Company, Staff states, considered upgrades to hydro, gas-fired thermal generation options (SCCT and CCCT), clean coal options (IGCC), super-critical pulverized coal, nuclear, geothermal and a wide variety of DSM options. Sterling, Tr. p. 1041.

- PURPA projects, Staff contends, cannot be planned on by the Company as a reliable option for meeting baseload needs – citing contract wind and geothermal on-line delays. Sterling, Tr. p. 1042. From 2005 to the present, PURPA QFs with a total capacity of 175.5 MW have signed contracts with Idaho Power but have yet to come on-line. A total of 21.6 MW of signed contracts have been terminated during this same time period. Projects with a capacity of 107 MW have come on-line. Sterling, Tr. pp. 1028-1029. Planned amounts of geothermal power, Staff notes, have also failed to materialize. In a 2006 RFP, a bid was accepted by Idaho Power to provide 45.5 MW and have facilities on-line between October 2007 and January 2011. So far only 13 MW have been developed, and contracts for the remaining have not been executed. In 2008, the Company issued another RFP seeking 50-100 MW of additional geothermal. No contracts have been signed. Sterling, Tr. p. 1029.

- Firm wholesale purchases –

Firm purchases of wholesale power by the Company, Staff states, require necessary transmission. Long-term reliance on eastside transmission capacity for baseload or peak hour needs is probably not feasible, Staff contends, until completion of the planned Gateway West transmission project (500 kV across southern Idaho and Wyoming). Any use of import capacity for purchases, Staff notes, also makes it unavailable in the event of a system emergency. Sterling, Tr. p. 1044.

- Relying on the market as an alternative to building new generation, Staff contends, carries greater risk and the potential for price volatility. Staff notes as does the Company that there are transmission constraints on imports from the Northwest that make locating new generation near its load center a prudent planning decision. Sterling, Tr. p. 1044.

- Transmission upgrades, Staff contends, are not an alternative to a new baseload power plant – they are a necessary component. Sterling, Tr. p. 1045. Staff notes the following recent upgrades and planned transmission projects:

> Brownlee to Oxbow (completed late 2003)
> Increased Brownlee east capacity by 100 MW
>
> Borah-Westpath (completed May 2007)
> Increased Borah-West transmission capacity by 250 MW
>
> The Boardman to Hemingway (B2H) 500 kV project included in the 2006 IRP preferred portfolio for 2012 would increase transmission capacity from the Northwest by 225 MW – this project has been delayed to 2015.
>
> Gateway West project
> Plan to build more than 1,000 miles of 500 kV transmission from Glenrock, Wyoming to Melba, Idaho.

Sterling, Tr. pp. 1045-1046.

- Conservation

A diverse resource portfolio, Staff contends, should include cost-effective energy conservation. Tr. p. 1046. Idaho Power for long-term planning of energy conservation and demand response programs, Staff states, relies on the IRP process, consultation with the energy efficiency advisory group and participation in regional energy efficiency organizations. Sterling, Tr. p. 1046.

Staff believes that the Company has strengthened its commitment to achieving all cost-effective energy efficiency and demand response potential. Sterling, Tr. p. 1047. Conservation programs by themselves, Staff contends, cannot achieve enough demand reduction to realistically satisfy the Company's immediate need to meet growing loads. Sterling, Tr. p. 1047.

Intervenors

The Intervenors have not taken the position that Langley Gulch will never be needed – simply that the economy has caused a slippage in that "need." Renewed Motion to Stay, p. 10. Intervenors, however, contend that the Company, in violation of Commission mandate, has not fully complied with the Commission's direction in December 2006, to "diligently and vigorously pursue all available cost effective DSM, conservation and pricing options that could potentially displace or defer the need for additional future peaking generation." Case No. IPC-E-06-09 (Evander Andrews), Order No. 30201. Renewed Motion, p. 2. Intervenors cite a 1986 Ninth Circuit Court opinion for its contention that "cost-effective" conservation measures are all such measures with marginal costs less than the cost of a generating resource to be acquired." In this proceeding, Intervenors accept the record indicating the [estimated] levelized cost of [a combined-cycle combustion turbine] to be $0.126/kWh. Intervenors then note that in the case of Langley Gulch, not only has the Company not implemented all conservation measures costing less than $0.126/kWh, it has yet to even compile a list of all such opportunities. *Citing* Pub. Exh. 901, p. 11. Renewed Motion, pp. 2-3.

CAPAI's witness Teri Ottens representing the low-income sector contends that Idaho electrics are not pursuing aggressively enough cost-effective low-income weatherization. Tr. p. 931. Out of 10,000 LIHEAP-eligible households in the state, she states, only 1,500 have actually been weatherized. Ottens, Tr. pp. 932, 944.

Idaho Power Response to Intervenors

Idaho Power disagrees with criticism of its commitment to energy efficiency and DSM. The Company contends that it is pursuing all cost-effective efficiency and DSM programs; some programs, however, it states, take years to develop and market. It also takes customer participation. Pengilly, Tr. p. 777. The Company's DSM programs continue to ramp up slowly. As participation increases, the Company expects that the effect of DSM on the load/resource balance will be greater and could have an impact on resource timing. Pengilly, Tr. p. 781. Right now, the Company offers a demand response program to all of its customer classes except small commercial. Pengilly, Tr. p. 767. Company witness Pengilly estimates 312 MW of DSM by 2013, 8% of forecasted peak demand. Ottens, Tr. p. 941.

Regarding use of the alleged levelized cost of a combined-cycle combustion turbine ($0.126/kWh) as a measure of cost-effective programs, the Company states that it does consider levelized costs in its analysis, but a program or a measure can have a high or a low levelized cost and still not be cost-effective. Pengilly, Tr. pp. 770-771. The Company bases its cost-effectiveness analysis and tests on the California Manual and the EPRI Tag Manual. It believes a better approach than the metric proposed by the public witness, Michael Heckler (Exhibit 901), is to determine cost-effectiveness first and then look at the levelized cost. Pengilly, Tr. p. 771, *see* Company description of cost-effective, Pengilly, Tr. pp. 773-775. The Company notes also that the avoided costs derived from the IRP and AURORA process is more robust than a simple comparison to single plant. Pengilly, Tr. p. 778.

Load Forecast/Timing

Consistent with its 2006 IRP, 2008 update and revised load forecasts in December 2008 (residential and commercial) and May 2009 (special contracts); Idaho Power forecasts the need for an additional baseload resource in 2012. Bokenkamp, Tr. pp. 260; 281. The primary driver of the need for the resource, the Company states, is load growth. Bokenkamp, Tr. p. 260. Langley Gulch, the Company contends, is expected to operate as an energy and capacity or "baseload" resource, following load and providing additional up and down regulation capability. The need for the resource will be greatest during summer peak load hours. Bokenkamp, Tr. p. 290.

The Company's May 2009 load forecast (Exhibit 10) incorporates updates to special contracts (customers with loads greater than 25 MW) and includes the most recent estimates of peak-hour contribution from the Irrigation Peak Rewards Program, the A/C Cool Credit Program and large commercial DSM. It also includes updated levels of firm import capability from the Pacific Northwest (114 MW) and wholesale firm energy purchases capable of being delivered to the Company's eastside. Bokenkamp, Tr. p. 280. Exhibit 10 does not include the recently acquired flexibility to reduce Hoku (an industrial special contract customer) loads by 39 MW between June 15, 2012 and August 15, 2012. Bokenkamp, Tr. p. 282.

Idaho Power uses two primary criteria in its planning to assess the need for new resources – one is based on energy needs and the other is based on capacity needs. Based on its May 2009 load forecast, the Company projects significant peak-hour deficits during July for the years 2009-2012 of 166 MW, 40 MW, 132 MW and 18 MW respectively; assuming Langley

Gulch is on-line. Bokenkamp, Tr. p. 280. The peak-hour load and resource balance assumes that the Company's existing natural gas-fired peaking facilities are in operation and contributing 416 MW. Bokenkamp, Tr. p. 286.

From an average energy perspective, using the May 2009 load forecast and the aforementioned assumptions, the Company projects average energy deficits during July for the years 2009-2012 of 365 aMW, 368 aMW, 421 aMW and 285 aMW respectively; assuming Langley Gulch is on-line. Bokenkamp, Tr. pp. 280-281. From an economic perspective, the Company notes that peakers are typically the last resource to dispatch. If operated for a full half-month the peakers would reduce the July 2012 deficit by 200 aMW. Bokenkamp, Tr. p. 286.

On a planning basis, if Snake River base flows continue to decline, Idaho Power's energy position will deteriorate. And if carbon legislation forces the Company to reduce the output of its coal-fired facilities, it will deteriorate even further. Bokenkamp, Tr. p. 289; Exh. 10.

The amount of energy the Company expects to have available from Langley Gulch for planning purposes at a capacity factor of 84% is 251 aMW. Bokenkamp, Tr. pp. 293; Yankel, 999. If future load forecasts indicate reduced loads in 2012, the Company states it will be well positioned to reduce its historic reliance on energy imported from the Pacific Northwest; to better integrate fluctuations of wind generation; and to deal with carbon legislation. Bokenkamp, Tr. p. 291.

The Company consultant, Michael Mace, states that Idaho Power, like any other utility planning for resources with long-lead times, is necessarily engaged in decision-making under uncertainty. Mace, Tr. p. 62. The Company's August 2007, August 2008, and May 2009 load forecasts, he states, were all reasonable when made. Mace, Tr. p. 62. The Company's load forecast has progressively reflected a slowing economy. Mace, Tr. p. 64; Exh. 15. To assist in its forecasting following the economic downturn in the fall of 2008, the Company contracted with Moody in April 2009 to provide macro-economic forecast data for Idaho counties as well as its two major service centers (Boise/Pocatello). Mace, Tr. p. 74; Exh. 21-25. Idaho Power bases the reasonableness of its May 2009 forecast and rather robust recovery on Moody's evaluation. Mace, Tr. p. 102. Moody's expects the economy to show signs of improvement by 2010. Exh. 16.