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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF INTERMOUNTAIN GAS COMPANY'S 2007-2011 INTEGRATED RESOURCE PLAN.	**CASE NO. INT-G-06-3**
	COMMENTS OF THE COMMISSION STAFF

The Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Cecelia A. Gassner, Deputy Attorney General, in response to the Notice of Filing and Notice of Modified Procedure in Order No. 30090 issued on June 30, 2006, submits the following comments.

BACKGROUND

On May 1, 2006, Intermountain Gas Company ("Intermountain" or "Company") filed its 2006 Integrated Resource Plan (IRP) for the years 2007-2011 with the Commission. In the Executive Summary of the Company's IRP, the Company states that the IRP is meant to describe the currently anticipated conditions from 2007-2011. It further states that the document is meant to present strong guidelines rather than be "a prescription for all future energy resources." IRP at 1. The Company is the sole distributor of natural gas in southern Idaho, serving 275,800 customers in 74 communities during the first half of fiscal year 2006. Its system contains over 10,000 miles of transmission, distribution and service lines. *Id.* In fiscal year 2005, over 446 miles of distribution and service lines were added in response to new customer additions and to maintain service for the growing customer base. *Id.*

Intermountain's two major markets are the residential/commercial market (the "core market") and the industrial market. *Id.* Intermountain saw an increase of 5% in average residential and commercial customers during the first half of fiscal year 2006. *Id.* Forty-four percent (44%) of the throughput on Intermountain's system during fiscal year 2005 was attributable to industrial sales and transportation. *Id.*

According to the IRP, the peak day send-out studies and load duration curves were developed under design weather conditions to determine the magnitude and timing of future deficiencies in firm peak day delivery capability. Residential, commercial and industrial peak day load growth on the Company's system is forecast to grow at an annual average rate of 4% over the next five years. The Company calculated the growth for the system as a whole as well as for the separate regions in which the Company operates. When forecasted peak day send-out is matched against existing resources, a peak day delivery deficit occurs during January 2007. According to the Company, that peak day deficit increases at a rate of 38% per year for the planning period if no action is taken. According to the Company's calculations, a deficit of firm capacity begins to occur near the peak day beginning in the winter of 2009. IRP at 4. The IRP sets forth the following abbreviated analysis of the Company's main service regions:

Idaho Falls Lateral Region

The Idaho Falls Lateral (IFL) region serves many cities between Pocatello to the south and St. Anthony to the north. The residential, commercial and industrial load served off the IFL represents approximately 15% of the total Company customers and 18% of the Company's total winter send-out during December of 2005. *Id.* When forecasted peak day send-out on the IFL is matched against the existing peak day distribution capacity, a peak day delivery deficit occurs during 2007 and increases thereafter. *Id.* Intermountain believes that small, short direction peak day distribution delivery deficits in the future can be mitigated by working with customers who have the potential to cut their peak day consumption by switching to fuel oil during extreme cold temperatures. IRP at 5. However, the Company states that the projected delivery deficits are of such magnitude that "looping" of the existing system is warranted to add necessary firm delivery capability to the area.

Sun Valley Lateral Region

The Company's residential, commercial and industrial customers in the Sun Valley Lateral (SVL) region account for 4% of the total customer base and 4% of the Company's total winter send-out during December of 2005. *Id.* When forecasted peak day send-out on the SVL is matched against the existing peak day distribution capacity, a peak day delivery deficit occurs during 2009 and increases thereafter. The tourism industry-related industrial load on the SVL is limited in size and does not currently have the capability to switch to alternative fuels in order to mitigate peak day send-out. IRP at 6. The Company believes that the growth in the SVL will warrant future upgrades to the existing pipeline system, and the Company plans to increase the delivery capability and capacity on the SVL through a series of cost-effective system upgrades. *Id.*

Canyon County Region

Fourteen percent (14%) of the Company's residential, commercial and industrial load is served off the Canyon County Lateral (CCL) region, and it accounted for 13% of the Company's total winter send-out during December of 2005. *Id.* When forecasted peak day send-out on the CCL is matched against the existing peak day distribution capacity, a peak day delivery deficit occurs during 2007 and increases thereafter. *Id.* The industrial customer base in the CCL region does not currently have the capability to switch to alternative fuels as a means of mitigating peak day send-out and the Company states that it is currently exploring optional means of enhancing the distribution capability in this region. IRP at 7.

STAFF ANALYSIS

PURPA Requirements

In accordance with the Public Utilities Regulatory Policy Act of 1978 (PURPA) (as amended by the 1992 Energy Policy Act), Commission Orders No. 25342, 27024 and 27098 require that the Company submit an Integrated Resource Plan (IRP) to the Commission every two years, addressing the following elements:

- Demand Forecasting
- Assessment of Efficiency Improvements (DSM Actions) & Avoided Costs
- Natural Gas Supply Options
- Natural Gas Purchasing Options and Cost effectiveness
- Integration of Demand and Resources
- Two-Year Action Plan
- Relationship Between Consecutive Plans (2004 Plan to 2006 Plan)
- Public Participation

The Company's 2006 IRP addressed each of these elements to various degrees, as described in more detail below.

Demand Forecasting

In June 1997 the Commission granted the Company's request to change the planning horizon for the Company's IRP process from twenty years to five years. See Order No. 27024. The planning period of 2007–2011 used for this IRP meets that requirement. The Company forecast, which is the basis for the 5-year planning period, provides daily, monthly and peak demands and predicts significant growth of peak demand in the core sectors of residential and commercial customers and stable peak demand in the industrial sector over the planning period. The forecast is based on: 1) growth in the number of households in the service territory commensurate with growth of the population and the economy, 2) corresponding growth in the number of small commercial customers, and 3) conversion to natural gas use by residences that presently do not use natural gas.

It is the Staff's opinion that, in general, the forecasting inputs and methodologies used by the Company are neither as comprehensive nor as robust as they could be. Although Staff concurs that some of the aspects of the modeling may be adequate, there are other factors that should undergo a wider range of analysis than the Company performed here. The IRP should be considered a comprehensive planning document performed for the benefit of the utility's customers. As such, and as noted in comments below, the Company should not shy away from addressing multiple scenarios and sensitivity analyses for such items as natural gas pricing or factors effecting demand when performing the analysis necessary for the IRP.

The Company relies on the May 2005 economic forecast for the State of Idaho issued by John S. Church (the "Church forecast") for both the population and economic growth inputs to its forecasts. The Church forecast uses household, employment and wage data to set a baseline forecast and high and low growth forecasts. Although it would be better to use a more recent forecast, Staff realizes that the 2005 forecast was the latest available when the IRP was prepared. The Staff deems this forecast to be satisfactory when considered with the conservatism of the heating-degree design year.

In its forecast model, Intermountain uses a Design Heating Degree Year based on the coldest 12-month period of the preceding 30 years with some modification (October 1984 through September 1985). The modifications are: 1) that the coldest month of the 30-year record period replaces the coldest month for the design year (in this case, December 1985 replaced January 1984), 2) the coldest day of the record period is used to set the peak demand day, and 3) the heating degree-days in the remaining winter and shoulder months were increased by one percent in recognition of the potential for colder weather in any month. The resulting heating design year is compared to the coldest year (1985) and to the 30-year weighted normalized average of the period of record in Graph 1. IRP at 30. Staff agrees with use of this conservative design year data that provides a capacity to deliver commodity on the peak day that is more than one-third greater than that needed to deliver the average peak of the period of record.

Market penetration rates for new households and customer conversion rates from other energy sources for each service region during the planning period are presented in tabular format. IRP at 21-22. The market penetration numbers presented in the IRP are more realistic than those presented in the 2004 IRP. However, the increasing market penetration going forward seems contradictory to market conditions and requires more explanation. For example, the efficiency, availability and application methods of heat pumps make them competitive with central natural gas heat at today's prices and it might be expected that electric heat will gain market share. In such a case, the market penetration numbers would at least stay steady or perhaps slightly decrease over time.

The conversion rates for existing homes are less optimistic than in the previous IRP, however, those conversion rates are presented as generally increasing over the planning period. This seems counterintuitive since conversion reduces the size of the non-natural gas users market. Given the large increase in retail natural gas prices in the past few years, while electric prices have been relatively stable, the decrease in conversion rates is logical but the forecast increase in conversion is not. The Company should address market penetration and conversion rates in more detail in future IRPs to expand upon the reasoning behind the Company's analysis that gas use will increase despite market forces that would otherwise lead economic forecasters to conclude that gas use would decrease.

In the Company's forecast, total daily usage during the peak months of November through February for residential and small commercial customers is determined through multiple linear regression analysis and summed for monthly and annual demand. Each of the peak months is individually modeled to establish customer usage through heating degree-days. Non-peak weather sensitive usage is derived by subtracting non-heating base usage (defined as use during July and August) from the remaining months and applying a separate weather normalization analysis to the individual month on a daily basis.

Staff believes this to be an overly simplistic forecasting method that ignores other factors driving demand, such as prices of natural gas and electricity, seasonality, and timed heating systems among other factors. Use of one or more of these other factors could be included to improve the model with little computational cost. Forecasts can and should be improved whenever cost effective with the intent of solidifying the Company's prescribed action plan. Staff recommends that in future IRPs, models that were tested but subsequently rejected in favor of the documented models be reported. Finally, the Company may wish to consider modeling the RS-1, RS-2,[1] and small commercial classes separately. It is reasonable to expect a different response to weather patterns for the three groups of customers based on their characteristics.

In its forecasts, the Company uses a set of three price curves, one each for pricing at Sumas, AECO and the Rockies for the IRP Planning Period (Exhibit No. 4, Appendix A, Chart 4.2). This set of prices is used in the computer model to determine costs associated with resource selection and to calculate the final costs resulting from the model selections. The Company does not state in the IRP the source of the pricing nor does it make use of a range of pricing that might correspond to the different economic cases used for the IRP.

Separately from the IRP, in a response to a production request, the Company states that it used a single source for the natural gas pricing used in the IRP, the NYMEX market close data plus basin differential pricing provided by IGI Resources, a BP Energy Company. No effective date or dates for the price data was stated. The Company also stated in its response to a production request that an additional pricing data point from November 6, 2005 was used in the model to check for the impacts of differing pricing and that the results did not materially effect the model's optimization. The Company goes on to state that inclusion of other forecast data would result in as many as nine scenarios (low, medium and high customer growth for each pricing scenario) without improving the IRP. These scenarios or sensitivity analyses are exactly the product that Staff believes should be published in the IRP in order to show that the IRP has resulted in selection of the best plan going forward. Otherwise, the reader has no basis for believing that the Company has used anything other than intuition and reliance on a unique

[1] RS-1 and RS-2 refer to the Company's two residential rate classes. RS-1 includes customers who do not have both a gas furnace and gas water heater, regardless of other appliances. RS-2 customers have at least a gas furnace and a gas water heater. IRP at 10.

forecast to prepare the plan. Staff believes the number of scenarios that are necessary or the computer sensitivity runs necessary to develop those scenarios is not an undue burden. Many other utilities perform literally hundreds of runs for many scenarios to arrive at their planning results.

Given that the IRP is written evidence that the utility has conducted a comprehensive analysis of possible demand and supply scenarios, Staff believes it to be appropriate to use a range of natural gas pricing forecasts applied to the economic bases of the IRP and to consider the quality of multiple sources for those price forecasts. Also, Staff believes it is appropriate to address the range of expected pricing in terms of any impacts on planning that expected or possible price changes may have, such as changes in supply, a move to use more or less storage, more or less use of hedging, or a change in consumption due to price change (e.g. price elasticity, which is addressed below). Staff recommends that the Commission require the Company to use a range of natural gas price forecasts that consider multiple sources and inclusion of sensitivity analysis with regard to economic issues in future IRPs. At least a half-dozen other natural gas price forecasts exist that could be used for comparison, to ensure that too much weight is placed in merely a single forecasted price set.

As mentioned, the demand forecast appears to lack certain considerations, including the price elasticity of demand. In the past, this factor has often been thought of as not significant within the retail price levels of natural gas. However, the large price increases of 2005 have resulted in estimates of price elasticity in the range of 0.10-0.15 applying to the present range of natural gas prices. This means that a 1% increase in price results in a 0.10-0.15% decrease in demand. With a 25% price increase (in 2005 the Company's retail price increased 27%), the resulting expected change in demand would be 2.50-3.75 %. Staff considers this to be a significant change. In its response to a production request on this topic, the Company states that it has considered addressing price elasticity of demand but believes it is not appropriate, primarily due to its belief that price elasticity of demand will not effect the design weather assumptions for the coldest day to be served. Staff understands that the Company may logically come to that conclusion in its analysis, but would prefer to see the analysis conducted and presented rather than have a simple assumption drive the IRP. The Company also states that it does not wish to include price elasticity of demand because it would add additional possible scenarios to be included in the IRP. As Staff has noted, that is precisely what is needed here – an examination of all likely scenarios in order to derive the plan that will best meet customer demands. Staff recommends that the Commission require price elasticity of demand to be addressed in future IRPs to capture the effect the change in the price of the commodity may have on consumer demand.

Assessment of Efficiency Improvements (DSM Resource Options)

In response to an April 27, 1997 filing by the Company (Case No. INT-G-97-2), the Commission issued Order No. 27098 allowing the Company, in its biennial IRP, to address efficiency measures with a "general explanation with each IRP filing of whether there are cost effective [demand-side management (DSM)] opportunities." Order No. 27098 at 2. Prior to that time the Commission required that the IRP address "...a full spectrum of opportunities available to the Company, including conservation and efficiency measures... ." Order No. 25342.

In addressing efficiency, the IRP provides an overview of growth of the North American natural gas markets and makes its case for natural gas being the most efficient energy source available. IRP at 58-63. The Company goes further by addressing, among other things, its support and promotion of:

- Building codes requiring increased use of energy efficient equipment and materials;
- The Company's participation in the Gas Technology Institute's research and development of higher efficiency applications for natural gas;
- The Company's customer education practices that address efficiency;
- Its participation in the Parade of Homes where they sponsored use of high efficiency furnaces;
- Sponsorship of a half day Energy Resources Symposium;
- Outreach to educate senior citizens about conservation tips and payment options; and
- Past offering of rebates for customers that convert to high efficiency furnaces and several other educational activities.

Beyond a very general statement of support for these and similar activities, there is no mention in the IRP of any efficiency or DSM programs or evaluations of those programs being performed or reviewed by the Company. Also lacking is any analysis to identify whether there are other cost-effective DSM opportunities available.

The Company addresses the value of natural gas in replacing electricity for heat as a more efficient use of heat than the generation of electricity through combustion of natural gas or any other fossil fuel. In its assessment the Company calculates that without the natural gas heat used in 2004, "...Idaho Power's winter peak load could reach 4,259 megawatts, a 94%

increase!" IRP at 62. This section seems to justify greater gas consumption rather than promote more efficient use of existing supply.

In response to a production request asking the Company, "What efficiency measures did the Company review and consider in the 2006 IRP process and what were the results of those reviews?" the Company responded as follows:

> All of Intermountain Gas Company's Integrated Resource Plans that were filed subsequent to the above referenced Order Number, including the 2006 IRP, included a listing of "cost effective DSM opportunities." These measures are more fully explained in the Company's filed IRP as contained in the section "The Efficient and Direct Use of Natural Gas."
>
> As previously noted, the Company actively promotes the wise and efficient use of natural gas. The aforementioned media campaigns, conservation information and education on the Company's website, and conservation minded bill stuffers all focus on cost effective energy efficiency measures. The Company credits these efforts with a measurable decline in weather adjusted baseload consumption.

Response of Company to First Set of Production Requests at 6.

Evaluation and use of cost-effective demand-side resources in a utility's resource mix is the purpose of an integrated plan. Staff believes that education and information are an important part of DSM, however, providing information and education are not DSM measures in that they do not directly create alternative resources that can be quantified and substituted for supply side resources.

Given the recent history of extreme upward price pressure and volatility in the natural gas markets, the impact of those prices on consumers, and the fact that there are few, if any, expectations of substantial decreases in natural gas prices, Staff considers the IRP's analysis of cost-effective DSM measures to be inadequate, and believes that the Company has failed in this IRP to satisfy the requirements of Commission Order No. 27098. It is more important than ever that the Company help customers manage their consumption of natural gas. Conservation of this resource is good for customers, the economy and business. Staff recommends that the Commission direct the Company to address the "full spectrum of opportunities available to the Company, including conservation and efficiency measures" that was part of the IRP process prior to Order No. 27098. Staff believes that the IRP process should be expanded to require cost/benefit evaluation of all feasible DSM programs and adoption of a mechanism that will result in cost-effective DSM measures being implemented.

Natural Gas Supply Options

The Company addresses commodity supply in two sections of the IRP, "Traditional Supply and Deliverability Resources" and "Non-Traditional Supply Resources." IRP at 45-53 and 54-55, respectively. Intermountain currently accesses natural gas from two supply basins, the Rocky Mountain Region and the Western Canadian Sedimentary Basin (British Columbia and Alberta) through three pipeline systems, all of which reach the Company's service area via the Northwest Pipeline System. The basins currently supplying natural gas to the Company are quite large and have significant reserves. These same pipeline systems could be used in the future to access additional sources of natural gas.

The Company's extensive use of natural gas storage to assure the ability to meet winter demands (especially winter peak demands) provides the added benefit of significantly mitigating high winter natural gas prices. The Company utilizes both underground and liquefied storage. The Company owns underground storage in three different and geographically diverse locations. The Company's underground storage is located to the west at Jackson Prairie in Washington State, to the north at AECO in Alberta and to the southeast at Clay Basin in Utah. Intermountain owns liquefied storage in two locations, Northwest Pipelines liquefaction facility in Washington and a Company-owned liquefaction/gasification facility within the Company's service territory west of Boise. All of the Company's out-of-service-territory storage is either bundled with transportation to the service territory or is combined with Company-contracted transportation to the service territory.

Two types of non-traditional resources are available to the Company: 1) the encouragement customers (who have the capability to do so) to switch fuels from fuel oil to coal, and 2) the Company's use of alternative commodities, such as propane and transportable liquefied natural gas. The Company's physical supply of natural gas is diversified by geographical source and deliverability. In Staff's opinion the Company has adequately addressed supply-side options in the IRP.

Natural Gas Purchasing Options and Cost Effectiveness

Intermountain's purchasing strategies for natural gas make it the lowest cost provider of the two natural gas companies providing retail service in Idaho. This is due in large part to the substantial use of storage gas purchased at summer prices. This year most of the summer gas purchased for storage injections and free-flowing gas was hedged at prices well below the existing weighted average cost of gas (WACOG). This type of hedging, relative to the current

WACOG, is consistent with the "Gas Supply Risk Management Program."[2] The Company and Staff continue to evaluate the risk management guidelines within this program to manage the risk and price volatility to customers.

The Company's documentation of its market evaluations and market fundamentals continues to improve. The market expertise and experience of the Company and its purchasing agent are extensive and will provide the background to evaluate the current guidelines and expand the Gas Supply Risk Management Program as the Company and Staff continue to meet on this topic.

Integration of Demand and Resources

The IRP section entitled "Load Duration Curves" identifies certain delivery constraints. IRP at 42. These constraints fall into two categories: 1) deficits in delivery to the Company's system from the interstate pipeline, and 2) deficits in the Company's distribution system capacity for delivery to its customers. Deficits of delivery into the system are shown in the following table:

INTO SYSTEM PEAK DAY DELIVERY DEFICITS (mmbtu) from Ex. 3[3]

FISCAL YEAR	2007		2008		2009		2010		2011	
Total Company Deliverability	High Growth	30,743	High Growth	49,898	High Growth	75,406	High Growth	90,954	High Growth	115,545
	Base Case	**23,316**	**Base Case**	**36,342**	**Base Case**	**55,950**	**Base Case**	**66,605**	**Base Case**	**85,070**
	Low Growth	13,886	Low Growth	19,561	Low Growth	30,914	Low Growth	31,894	Low Growth	40,469

In addition, for distribution system delivery needs, the Idaho Falls Lateral, Sun Valley Lateral, and Canyon County service areas are the only areas forecasted to have deficits for the planning period. Those forecast deficits are shown below:

[2] The objectives of Intermountain Gas Company's Gas Supply Risk Management Program are to (a) help ensure adequate gas supplies, transportation and storage are available for its customers; (b) mitigate the adverse impact that significant price movements in the natural gas commodity can have on the Company's supplies, customers and other operations; and (c) minimize the credit risk inherent in the implementation of certain price risk reducing strategies.
[3] Table created by Commission Staff using data provided by the Company in its IRP.

INTRA-SYSTEM DELIVERY DEFICITS (mmbtu) from Ex. 3[4]

FISCAL YEAR	2007		2008		2009		2010		2011	
Idaho Fall Lateral	High Growth	4,994	High Growth	9,513	High Growth	13,971	High Growth	18,037	High Growth	22,891
	Base Case	**3,045**	**Base Case**	**5,765**	**Base Case**	**8,686**	**Base Case**	**11,446**	**Base Case**	**14,108**
	Low Growth	1,946	Low Growth	3,830	Low Growth	5,725	Low Growth	10,321	Low Growth	8,069
Sun Valley Lateral	High Growth	0	High Growth	0	High Growth	711	High Growth	1,789	High Growth	2,848
	Base Case	**0**	**Base Case**	**0**	**Base Case**	**37**	**Base Case**	**929**	**Base Case**	**1,852**
	Low Growth	0	Low Growth	0	Low Growth	0	Low Growth	0	Low Growth	0
Canyon County	High Growth	861	High Growth	5,675	High Growth	10,013	High Growth	13,979	High Growth	18,057
	Base Case	**374**	**Base Case**	**4,984**	**Base Case**	**8,860**	**Base Case**	**12,362**	**Base Case**	**15,897**
	Low Growth	0	Low Growth	2,862	Low Growth	5,640	Low Growth	7,931	Low Growth	10,237

These deficits are addressed in the IRP section entitled "Resource Optimization." IRP at 64. For the system as whole the Company forecasts, in the year 1 base case, a peak day deficit in delivery into the system of 23,316 mmbtu/day in 2007 growing to 85,070 in 2011. The IRP states that this deficit will be met by acquiring an incremental 25,000 mmbtu of interstate delivery on Northwest Pipeline in Year 1 of the plan (2007) along with unspecified contracts for matching commodity. In the IRP the Company also addresses the need for 36,900 mmbtu in year 5, but is less specific about how that deficit will be satisfied. The intervening years are not addressed. The Company's modeling results designate "fill" for the needed commodity for this deficit. "Fill" is the model's name for a generic acquisition. Although the data is available in tables found in the exhibits, in the IRP the Company makes no statement about what specific purchases or storage plans exist to satisfy this "fill" requirement. An improvement to this part of the IRP would be for the Company to define the linkage between identifying the necessary resources and performance under its natural gas acquisition policies and the Risk Management Program.

The Company filed amended pages 43 and 44 to specifically identify the deficits for the planning period; however, the IRP does not match those deficits with planned resources. Staff believes that the IRP is intended to be a plan of <u>how</u> the Company will fulfill its obligations to supply its customers, but that piece is lacking in the IRP itself.

[4] Table created by Commission Staff using data provided by the Company in its IRP.

Outside of the IRP, in its response to a production request, the Company stated it was originally planned that specific lateral deficits will be met with specific resources as follows:

> Canyon County -
> a. 2007 - the relatively small deficit of 3,740 therms is eliminated by utilizing mobile LNG. From a real-world standpoint, it is possible that a deficit this small occurring on only one day may be also resolved from short-term operational efficiencies.
> b. 2008-11 - distribution main looping and pressure upgrades that add 170,000 therms of additional delivery capacity resolves all deficits thru 2011.
>
> Idaho Falls Lateral -
>
> c. 2007 – the 30,450 therm deficit is filled by using mobile LNG
> d. 2008 -09 – the deficits are almost entirely filled by adding 80,000 therms of capacity to the distribution facilities via the Phase V looping project.
> e. 2010-2011 these deficits are entirely filled by utilizing the Phase XI looping project that adds another 90,000 therms of capacity.
>
> Sun Valley Lateral -
>
> f. 2009 – the 370-therm deficit is filled via mobile LNG.
> g. 2010-2011 – the deficits for these years are entirely filled via a looping project that increases capacity by 40,000 therms."

Response by Company to First Set of Production Requests at 5.

Additionally, the Company states that further study has resulted in delaying the need for the above-mentioned resources as follows:

> Notwithstanding the above, subsequent to completing and filing the 2007-11 IRP with the Commission, the Company has further refined its plans to eliminate the projected distribution deficits in a more cost efficient manner. Interestingly enough, some of the early research conducted for this IRP led to discovering some technology enhancements that will allow the Company to forestall some very expensive pipeline upgrades in two areas of the system. These refinements are explained below:
>
> Canyon County -
> a. 2007-08 – further study of historical pressures from Northwest Pipeline and the ability to use the Company's system linepack for "temporary" storage indicate that in the near-term, the peak day deficits will lag prior estimates and the deficits will occur a later year and at a lesser magnitude. Consequently, the looping project that was to occur in 2007 can now be delayed until 2008.

b. 2008-11 – the looping project now planned for 2008 will continue to eliminate all remaining deficits projected thru 2011.

Idaho Falls Lateral –
c. 2007-08 - updated analysis forecast that, due to higher Northwest Pipeline pressure and temporary use of lateral "line pack", any deficits would occur later and would be smaller than earlier projected. Additionally, the Company has continued to research the mobile LNG technology and found that it can be employed on a larger scale over a longer period of time than was assumed in the IRP. Consequently, the looping projects previously projected for 2007 and 2009 may now be delayed until after 2011 saving the Company approximately $7.5 million.

Sun Valley Lateral –
a. Through the use of mobile LNG, the pipeline looping that was previously projected to occur in 2007 is now likely to be postponed until after 2011 saving the Company over $2.5 million.

Response of Company to First Set of Production Requests at 5-6.

After reviewing this response, Staff recommends that the Company publish an addendum to the Resource Optimization section of the IRP. The addendum should identify the individual deficits, each resource addition or change originally planned to satisfy those deficits, the changed situation and the resulting postponement of or newly planned resource that will be implemented to eliminate the deficit situations. Staff recommends that the Commission require the Company to specifically describe and evaluate the additional resources that will be acquired, developed or constructed to eliminate demand deficits in commodity and transportation in all future IRPs.

Two-Year Plan

Order No. 25342 mandated that each IRP include a two-year plan "outlining the specific actions to be taken by the utility in implementing" the IRP. Order No. 25342. Order No. 27024 granted the Company's request to submit a five-year IRP rather than a twenty-year IRP. Order No. 27024. In light of the Staff's experience in evaluating the Company's IRPs submitted since the issuance of Order No. 27024, the Staff respectfully recommends that if the Commission desires for the Company to continue submitting IRPs with a five-year forecast window, the Commission may wish to consider striking the requirement for the Company to submit a two-year plan within the IRP. The information presented in the five-year plan should provide information that would adequately fulfill the two-year plan's purpose, and the inclusion of the two-year plan within the Company's five-year IRP usually results in duplicative information that does not further illuminate the overall plan.

Relationship Between the Plans (2006 IRP vs. 2004 IRP)

Staff believes that the IRP satisfies this requirement. In the comparative analysis section of the IRP, the Company addresses the differences between the 2004 IRP and the present IRP. Each major section of the IRP is addressed and the significant differences between the two plans discussed.

Public Participation

The Company met the requirement for public participation in the IRP process. Public involvement in the IRP process consisted of a ½-day session wherein the Company met with customers, concerned consumer groups and Commission Staff to discuss the inputs to the IRP. Questions and comments were solicited from all present.

STAFF RECOMMENDATION

After a complete evaluation of the Company's IRP, its methodology and conclusions, the Staff recommends that the Commission direct the Company as follows:

1) That in future IRPs, models that were tested but subsequently rejected in favor of the documented models be reported (along with a summary of why the alternatives were rejected), including customer usage over seasonal and annual time periods, a range of natural gas price forecasts from multiple sources, and price elasticity of demand.
2) That in future IRPs, the Company address the "full spectrum of DSM opportunities available to the Company, including conservation and efficiency measures" that were part of the IRP process prior to Order No. 27098 and that the IRP process be modified to require that a cost/benefit evaluation of all feasible DSM measures be performed and that the Commission consider actions aimed at creating a mechanism that will result in all cost-effective DSM measures being implemented.
3) To specifically describe and evaluate the additional resources that will be acquired, developed or constructed to eliminate demand deficits in commodity supply and transportation in all future IRPs.

4) That the Company publish an addendum to the Resource Optimization section of the IRP addressing the changed lateral transportation capacity deficit positions stated in the Company's response to production request.

Respectfully submitted this 29th day of August 2006.

Cecelia A. Gassner
Deputy Attorney General

Technical Staff: Harry Hall

i:umisc:comments/intg06.3cghh

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 29TH DAY OF AUGUST 2006, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. INT-G-06-03, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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