BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA FOR A DETERMINATION THAT ADDITIONAL ELECTRIC GENERATING CAPACITY WILL BE USED AND USEFUL	)))))	CAUSE NO. PUD 200500516
APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA FOR A DETERMINATION THAT ADDITIONAL BASELOAD GENERATING CAPACITY WILL BE USED AND USEFUL	)))))	CAUSE NO. PUD 200600030
IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC FOR AN ORDER OF THE COMMISSION GRANTING PRE-APPROVAL TO CONSTRUCT RED ROCK GENERATING FACILITY AND AUTHORIZING A RECOVERY RIDER	)))))))	CAUSE NO. PUD 200700012

REDACTED VERSION

AMENDED

RESPONSIVE TESTIMONY

OF

JOHN G. ATHAS

ON BEHALF OF

OKLAHOMA ATTORNEY GENERAL

MAY 22, 2007

CAUSE NOs. PUD 200500516, PUD 200600030, and PUD 200700012

REDACTED RESPONSIVE TESTIMONY OF JOHN G. ATHAS

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I. QUALIFICATIONS

Q. Please state your name, position, and business address.

A. My name is John G. Athas. I am a Managing Consultant at La Capra Associates, Inc. My business address is 20 Winthrop Square, Boston, MA 02110.

Q. Please summarize your professional experience and qualifications.

A. I am an electric power industry planning specialist with over 25 years of experience in areas including strategic planning, integrated resource planning, generation planning, economic and financial analysis, marketing, wholesale power market analysis and forecasting, and electric power retail marketing, and rates and pricing.

I am currently a Managing Consultant at La Capra Associates and have served in that capacity since February, 2006. Since joining La Capra Associates, my work has included several aspects of power systems planning and electric industry restructuring, including wholesale and retail market formation, generation asset valuation, resource planning and resource adequacy studies, rates, contracting and retail power marketing.

Immediately prior to joining La Capra Associates, I worked as an independent consultant with Direct Energy developing retail electric business plans. From 2001 to 2005, I was an Associate Director of North American Electric Power at Cambridge Energy Research Associates ("CERA"). In that capacity I was responsible for market analysis and forecasting of power prices for the regions of the Eastern Interconnect for the US and Canada. This region includes the Southwest Power Pool. Prior to joining CERA, I had various planning positions at Northeast Utilities Service Company ("NU") on behalf of corporate NU and its regulated and competitive companies from 1981 through 2000. From 1987 to 1991, I was the Manager of Strategic Analysis and Long Term Resource

Planning at NU, where my responsibilities included conducting NU's Integrated Resource Planning, the analysis of the NU utility companies' competitive position, and various strategic planning efforts regarding diversification leading to the acquisition of HEC, Inc., an energy service company, and the formation of Charter Oak Energy, a competitive generation affiliate of NU.

I hold a Master's of Business Administration with a finance concentration from the University of Connecticut (1987), Master's of Science degree in Mechanical Engineering Sciences from Rensselaer Polytechnic Institute (1982) and a Bachelor of Engineering degree in Mechanical Engineering from the Cooper Union (1977).

A copy of my resume is attached hereto as Exhibit JGA-1.

Q. Please summarize La Capra Associates and its business.

A. La Capra Associates provides consulting services in energy planning, market analysis, and regulatory policy in the electricity and natural gas industries. We serve a national and international clientele from our offices in Boston, providing consulting services to a broad range of organizations involved with energy markets, including public and private utilities, energy producers and traders, financial institutions and investors, consumers, regulatory agencies, and public policy and energy research organizations. Our technical skills include power market forecasting models and methods, economics, management, planning, rates and pricing, energy procurement, and contracting. Over the past several years, our firm has been very active in electric industry restructuring issues, including stranded cost assessments, provider of last resort service, and wholesale and retail market formation. A significant portion of our work involves traditional regulated rate proceedings; this includes a major focus on power supply, base rate, and fuel and purchased power issues.

Q. Have you previously testified before this or other Commissions?

A. I have not previously testified before the Oklahoma Corporation Commission.

I have testified before state commissions in Massachusetts and Connecticut and have testified before siting agencies in Massachusetts and Connecticut. These appearances included topics of generation planning, integrated resource planning, competition, economic development and special utility customer contracts, and the licensing of Select Energy, NU's competitive energy affiliate.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you appearing in these proceedings?

A. I am testifying on behalf of the Oklahoma Attorney General ("AG"). La Capra Associates has been retained by the AG to provide advice and expert testimony with respect to the three Causes that have been consolidated into this proceeding.

Q. Please describe the purpose of your testimony.

A. At the AG's request, I am providing testimony and a statement of position pertaining to applications of Public Service Company of Oklahoma (PSO) and Oklahoma Gas and Electric (OG&E) for certain approvals for the proposed Red Rock generating facility.

My testimony addresses four specific areas of review performed by La Capra Associates regarding each company's analysis to show the need for its respective portion of the facility and that the Red Rock facility as proposed is the least cost alternative for each of the companies.

First, I will discuss our review of issues pertaining to OG&E's IRP analysis. Second, I discuss our review of PSO's IRP. Third, I will discuss the issues uncovered with the

Competitive Solicitation process. Finally this testimony will show that, when comparing the current cost estimated for the Red Rock facility to other base load and combined cycle capacity, Red Rock does have higher costs than alternatives.

In organizing the material I have referenced in my testimony, I have assembled Exhibit JGA-2, which contains the referenced Data Requests that do not otherwise have a specific exhibit number when referenced in the text of this testimony.

My testimony provides foundation and support for the complementary testimony offered by two other witnesses, Daniel Peaco and Lee Smith. Ms. Smith provides testimony pertaining to the cost recovery requests of both PSO and OG&E, and OG&E's rate and financial projections that provide the context for the requested cost recovery treatment for the facility. Mr. Peaco provides testimony pertaining to the overall determination of the validity of the request of the companies, the findings by La Capra Associates in review of the companies' requests, and recommendations of alternatives to the filed Red Rock Facility proposal. My testimony will provide a more detailed description of several facets of our review of the OG&E and PSO information filed in these proceedings.

Q. Would you summarize your findings with respect to the issues before the Commission in this proceeding?

A. In my review, I found that:

1) OG&E's forecast of its future energy requirements and peak load are overstated by approximately [redacted] GWH and [redacted] MW respectfully in 2012. This results from OG&E's incorrect depiction of the real price of electricity in its forecasting modeling. OG&E, which now forecasts a significant increase in price, utilized decreasing prices in its modeling.

2) OG&E's IRP analysis used a load forecast that included all of the forecasted wholesale customer load as well as the OG&E retail load. Eliminating the substantial portion of these loads that OG&E may not have in 2012 would reduce energy requirements in 2012 another 815 GWH and future peak demand by 125 MW in 2012 and thereafter.

3) OG&E has not reflected the potential of Demand-side Management (DSM) resources to economically reduce OG&E's system energy requirements and peak demands.

4) OG&E's IRP modeling analyses, which led OG&E to conclude that it had a need for base load resources and that the Red Rock generation project was a least cost alternative, was flawed. We have worked with OG&E to review these analyses and, in that process, have identified several errors in their economic modeling analyses. OG&E has acknowledged these problems and is working to address them.

5) OG&E did not provide any clear comparative analysis of the economics of the Red Rock project. The Company analysis, provided in response to our request on behalf of the Attorney General's office, appears to show that the Red Rock facility, introduced before 2014, would increase OG&E's system revenue requirements.

6) PSO's IRP analysis has overstated its peak demand and energy requirements. The PSO demand forecasting modeling has been updated since the 2005 IRP. PSO has [redacted] its 2012 peak demand estimates in its 2006 forecast by [redacted] MW in 2012. (Weaver Supplemental Exhibit SCW-3S)

7) PSO's IRP process dismisses economic Demand-side Management (DSM) resources that by our analysis have the potential to economically reduce its energy requirements by 736 GWH and peak demand by 90 MW. PSO's IRP eliminates DSM programs from further consideration during the screening process by its use of the

Rate Impact Test. These programs would pass a different test, the Total Resource Test, more commonly used and recommended by other utilities and regulators. If a pure revenue requirements test was used in PSO's DSM screening, a wide array of DSM programs would pass, involving all customer classes, totaling 500 MW in peak demand reduction. The revenue requirement minimization is the stated goal of PSO in the IRP.

8) PSO's IRP included cost estimates used to justify the need for base load generation as the least cost supply alternative in the IRP analysis. However, these estimates are significantly lower than the costs now estimated for the proposed Red Rock generation project. PSO's more recent analysis shows that the Red Rock project would have higher revenue requirements than a natural gas-fired combined cycle.

9) PSO's IRP does not address three risks that would impact the economics of its decision to propose the Red Rock project. This includes energy forecast, risks of changing environmental regulations for carbon emissions and the risk of higher installed capital costs for new generation.

10) PSO's Competitive Procurement process, which resulted in the proposed jointly owned Red Rock generating project, has shortcomings that call into question the validity of both PSO's and OG&E's claim that Red Rock is a cost effective generating capacity addition.

11) OG&E did not present a clear analysis that supports its assertion that Red Rock produces the lowest reasonable cost outcome. OG&E has responded to Data Requests with information that indicates that the Red Rock project would result in slightly higher revenue requirements than alternative generation plans.

12) When the current forecasted costs of the Red Rock generation facility are worked

into the analysis by the Companies, Red Rock can increase costs of the OG&E system and provide little change costs for the PSO system.

III. SPECIFIC ISSUES WITH OG&E's IRP ANALYSIS

A. OG&E's Analysis of the Economics of the Red Rock Generation Facility

Q. Has OG&E established that Ratepayers benefit from additional generation?

A. As discussed by Mr. Peaco, there are a number of ways by which a utility can establish "need" for a new resource. In this proceeding, OG&E has achieved none of them.

- OG&E has failed to demonstrate that it has a need for additional generating capacity in order to ensure the 12 percent capacity margin required by SPP for system reliability objectives.
- OG&E has failed to demonstrate that it has a need for additional generating capacity in order to improve the overall economics of the resource portfolio from which it meets its customers' electricity requirements.
- OG&E has failed to demonstrate that it has a need for additional generating capacity in order to improve the environmental performance of its resource portfolio.
- OG&E has failed to demonstrate that it has a need for additional generating capacity to meet any other alleged need.

Q. Has OG&E analysis established that there are ratepayer benefits from additional generation in response to increasing energy requirements and peak loads?

A. No. Let me begin by reviewing the results of OG&E's analysis of need for incremental capacity, presented in Exhibit JBL-2. The analysis that leads to the results presented in

Exhibit JBL-2 is implicit in Table II-8 of its IRP. Table II-8 identifies (see Line 5) the level of capacity additions required to ensure that the 12 percent capacity margin required by the Southwest Power Pool is preserved as loads increase through 2016 (as reflected in Line 7). I have replicated this analysis in Exhibit JGA-5, with some minor changes in format, in order to help illustrate the deficiencies that reside within this analysis.

Q. **Does Exhibit JBL-2 provide a reasonable assessment of the timing and magnitude of an OG&E system capacity shortfall?**

A. Exhibit JBL-2 does show a capacity shortfall in the near term for OG&E. This is reflected in Table II-8 of the IRP in the form of the "Additional Forecasted Capacity" (see Line 5). Table II-8 demonstrates the amount of capacity additions required for OG&E to avoid a capacity shortfall, assuming its 12% capacity margin obligation to SPP.

However, the analysis behind Exhibit JBL-2 Table II-8 is flawed. There are four notable problems. The first of these pertains to the underlying load forecast.

Q. **Have you prepared an Exhibit to help illustrate the problems with OG&E's load forecast?**

A. Yes. In Exhibit JGA-5 I have prepared a calculation of the company's need for additional capacity resources that parallels the presentation in Table II-8 of the IRP. The first table in Exhibit JGA-5 is a reformatted version of IRP Table II-8, with the reformatting done in order to show clearly the capacity surpluses and shortages that result under alternate assumptions on load and the levels of resource contributions.

Q. **What problems do you identify in the company's forecast capacity balance?**

A. There are several. First, the capacity requirements projection contained in Exhibit JBL-2 relies on an outdated load forecast, published in July 2005. The assessment should be based on the most recent load forecast. The most recent load forecast was published in August 2006 (Response to AG 2-9a). Note that the 2006 load forecast is somewhat higher than the previous forecast.

Q. Have you prepared a revised view of projected OG&E capacity balance that makes use of the most recent load forecast?

A. Yes, in the second table of Exhibit JGA-5 I have made modifications in order to introduce the 2006 forecast. Its effect on OG&E's on the timing and magnitude of a capacity shortfall for OG&E also can be seen in Exhibit JGA-5

Q. You indicate that there are flaws that undermine OG&E's assessment of its capacity requirements. What are the flaws in the company's capacity requirements analysis?

A. The first major flaw lies in OG&E's assumption that it will continue to be called upon to serve all the energy requirements and peak demands of its current wholesale customers. This assumption is evident in its load forecast (see, for example, Table 7 of Appendix B to the IRP).

Q. Why is this assumption problematic?

A. It is problematic because most of these customers (and more than [redacted] of this load) are not obligated to remain wholesale contract customers beyond [redacted]. (Data Request AG 2-46d) It is expected that the cost of Red Rock energy plus capacity will increase OG&E's average cost of power in the early years of Red Rock's operation. If wholesale load is to pay "its share" of Red Rock, wholesale rates will have to increase. It is also likely that these wholesale customers will have increasing competitive options that will enable them to purchase from alternate suppliers. Since these FERC loads may decrease by more than [redacted] before Red Rock goes into service, there does not seem to be any basis for including all of these loads in its analysis of the economics of base load capacity additions.

Q. What will the impact be if these wholesale contracts are terminated?

A. According to the response to AG-2-46, OG&E's roughly [redacted] MW of wholesale load contractual commitment can cease service by 2010. By including this wholesale load in its planning analysis, OG&E's overstates its energy obligation by [redacted]%.

Q. Please explain your second concern, regarding price elasticity effects in OG&E's load forecast.

A. The OG&E load forecast appears to be overstated because the forecast is based on a price of electricity forecast which is much lower than the price increases described by Mr. Hatfield. OG&E's load forecasts include the effect of price elasticity, which is about a negative 0.1% for residential and commercial customers (AG-19-3). However, its forecasts assume that real prices for electricity for these classes will decrease by about 14% from 2006 – 2012. The assumption about falling prices increases the load projection compared to what it would be if Mr. Hatfield's projected price increases had been used.

The problem lies in the fact that the assumption regarding future prices is in direct contradiction to OG&E's testimony that some large rate increases are expected due to both non-Red Rock capital expenditures and to Red Rock itself. OG&E has estimated, in response to AG-19-4, that its energy requirements would be 0.5% lower in 2012 ([redacted]

MW) in peak demand if it had assumed not a decrease in real prices but rather constant real prices. The forecast should reflect not only this, but also the impact of the higher real prices that the company predicts.

Q. Is there a third flaw in OG&E's load forecast analysis?

A. Yes. The load offsets that OG&E assumes from demand-side programs likely are far below the levels that could be realized through any reasonable effort to secure additional economic energy and demand savings. In any event, in its options for available resources, OG&E has failed to demonstrate that there are not more economic DSM resources that can be deployed rather than new generation.

Q. Please explain.

A. For example, the company tells us in its IRP (at ES-3) that they are doing a DSM study that was not considered in the IRP analysis. The company only presents the recent history of load curtailments (see AG 12-1; OCC 3-1). Also, the Company presents no analysis of the DSM program options regarding energy saving DSM programs in its IRP. Our detailed analysis (discussed later in this testimony) of the DSM program options suggest substantial energy and peak demand savings are potentially economic. Absent an OG&E analysis of DSM programs, we would suggest assuming similar reductions of 815 GWH of OG&E's energy and peak demand (125MW) are a reasonable proxy for the DSM resources that would be economic and available no matter what the alternative supply scenarios.

Q. How would OG&E's projected capacity and energy requirements change as a result of these issues?

A. I have prepared an illustrative view of the Company's need for additional capacity resources, including changes to reflect the concerns I have described. In particular, I assume that:

- OG&E's wholesale loads are excluded, including only its retail load forecast (in keeping with the response to AG 2-46(d);
- Price inputs in the load forecast reflects the rate increases that OG&E's projects in this proceeding; and
- The contributions from demand-side resources are increased to show that OG&E could obtain a strong contribution from energy saving efficiency based DSM programs as well as increase at least modestly its load curtailment program.

The changes to OG&E's projected capacity shortfall timing and magnitude resulting from these changed inputs are presented in Exhibit JGA-5

B. Concerns about OG&E's Analysis and Modeling Processes within IRP.

Q. Did OG&E conduct an economic modeling analysis of its system to demonstrate that its Red Rock proposal is superior to alternatives?

A. Yes. As presented in the OG&E Energy Integrated Resource Plan ("IRP"), the Company used portfolio resource planning models to analyze potential resource strategies from both a cost and a risk perspective. As explained in Mr. Langston's Direct Testimony at page 7, the Company explored different resource strategies and different generation expansion plans based on comparisons of their forecasted system net present value revenue requirements ("NPVRR") over a 30-year period. OG&E also developed and implemented a risk analysis that focused on the uncertainties surrounding key assumptions including fuel prices, environmental costs, capital investment costs, load growth and generating unit operational characteristics.

Q. Please describe the modeling process implemented by the company.

A. OG&E contracted with Burns and McDonnell to perform a generation technology assessment for use in its IRP. OG&E worked with Burns and McDonnell to develop a list of potential resource options that encompassed a range of fuel sources, technologies, and output capacity levels that were judged worthy of further consideration. These are listed in Section IV.A.1.a of the Company's IRP. In establishing the set of resource options for further exploration, certain resource options were deemed to be not realistic resource alternatives during the planning horizon because of technical and/or economic factors. Resources excluded from consideration are listed in that same Section of the IRP. Burns and McDonnell developed operating and cost assumptions for each of the resource options that were judged to warrant further consideration, for inclusion in modeling processes.

The Company relied on two models in its analysis of resource planning options. An initial set of analyses were performed using a Capacity Expansion Module, or CEM. This model was used to identify an optimal generation expansion plan for each of (1) OG&E's defined "base case" scenario (i.e., the Company's assumed base case conditions for customer loads, fuel prices, etc.); (2) four alternate scenarios developed by the company's consultant, Cambridge Energy Research Associates; and (3) and seven "sensitivity" scenarios that address different assumptions regarding the base expansion plan (see IRP Section IV.B.2. Table IV-9 presents the optimal capacity expansion strategies produced by CEM for each of the eleven alternate planning scenarios, as optimized across a 30-year horizon (see IRP Section IV.A.).

The CEM model is fairly efficient in its ability to explore a large number of competing resource options in identifying an optimum generation expansion plan in response to a given set of input conditions. However, CEM sacrifices a degree of accuracy to achieve this efficiency. Therefore, the company uses a Planning and Risk application, known as PAR, to evaluate the impact on total revenue requirements of the Base Case and alternate scenarios (see IRP Section IV.A). The PAR model also is used to explore the impacts of varying assumptions regarding four key variables (i.e., changing retail loads, changing natural gas prices, changing coal prices and potential emissions costs). IRP Figure IV-20 presents the NPVRR probability distribution based on PAR runs for all cases.

Q. What were the results of the company's modeling effort?

A. Table IV-9 of the IRP presents capacity expansion plans (i.e., the first ten years) and the NPVRR costs for each, for the "base case" and 11 alternate planning scenarios explored by OG&E. OG&E reports that the Red Rock facility (i.e., its proxy in the IRP process, a "Super PC-365" unit) was selected as part of the optimal portfolio under base case conditions and in six of the other planning scenarios.

Figure IV-20 of the IRP presents the results of the risk analysis that OG&E applies to each expansion plan. This analysis considers revenue requirements "at risk," due to variations in the possible cost outcomes for four major risk factors: the retail load forecast, natural gas prices, coal prices and emissions costs. Based on this analysis, the company concludes that the probability that its "base case" expansion plan (which includes Red Rock) will have the lowest NPVRR is approximately 65%. It also concludes that none of alternate expansion plans perform significantly better than the base case expansion plan. See Draft IRP at IV-26.

Q. How does OG&E use these results?

A. Based on the results of its analysis, OG&E recommends a resource procurement strategy that includes a "400 MW Joint Coal Base Load Unit" — i.e., Red Rock — entering commercial operation in 2011, and RFPs (and the Enid facility repair and upgrade) for peaking capacity to satisfy incremental capacity needs up until that coal plant enters commercial operation (see IRP Table V-1).

Q. Does OG&E's modeling analysis produce reasonable results?

A. No. There were a range of problems with OG&E's modeling processes that ultimately undermine the results of its IRP and render invalid the conclusion that Red Rock reasonably should be part of an optimal resource plan. These problems included the following:

- Deficiencies in the range of resource options explored by OG&E;
- Problems with model mechanics/the algorithms by which the model operated on input data;
- Problems with the data used as inputs to the model;
- Problems with the way in which certain model outputs were interpreted; and
- Problems with the risk analysis that represented the last step in the modeling process.

Q. Did these problems with the model by which OG&E developed its recommendations affect its IRP action plan?

A. Yes. These problems with OG&E's models distorted the output results of its resource planning models. Their presence raises serious questions regarding the validity of its resource planning recommendations identified by OG&E in the IRP.

Q. Did OG&E explore a number of potential resource options as part of its resource planning process?

A. The company explored the potential new capacity resources identified in Table IV-1 of its IRP.

Q. Did OG&E give adequate consideration to investments in demand-side resources as a potentially cost-effective response to load growth?

A. No. Demand-side options, efficiency based and load curtailment programs, have received inadequate attention from OG&E. In my judgment, to date an insufficient effort has been made to secure determine the economic potential for these resource to reduce either energy requirements or peak demand or both.

Q. What level of demand-side contribution has OG&E used in its IRP planning studies?

A. IRP Table II.8 shows that, for purpose of determining its capacity planning margins in the Base Case scenario, OG&E has assumed the level of peak demand reduction remains constant at the historical level, 127 MW across the study. Thus OG&E has made the simplistic assumption that it can not identify either economic energy efficiency or demand curtailment program that would prove to be economic.

Q. What is the source of the 127 MW contribution from demand-side resources that is factored into the IRP?

A. This figure is a capacity contribution for curtailable loads, which is based on the number of customers (and associated loads) signed up for the programs, as well as their expected participation if called upon to curtail their loads. OG&E indicates that this determination is reviewed annually (response to AG 12-1).

Q. Has there been a DSM Study performed for OG&E?

A. Yes, but only limited to studying demand response potential, not the potential of Demand Side programs. The Applied Energy Group, Inc. completed a Demand Response Study for OG&E in July of 2005 (see attachment OCC 3-3_Att.). The Demand Response Study states (at 34) that "this study represents a preliminary examination of the potential for demand response programs in OG&E's service territory." It also states that "there are indications that demand response may be cost-effective" and recommends that OG&E develop more data and analysis before embarking on further investment in demand response programs (Study at 34).

Q. Did OG&E implement the Applied Energy Group's recommendations?

A. The company states in its IRP Section III.A.5 that it is currently studying the potential to obtain incremental DSM resources. However, the study will not be completed until 2007, "and may require an update to the IRP if the results indicate that there are meaningful changes in the DSM capacity." It is important to note that we have not found anywhere in the IRP analysis and documents that models DSM as anything other than offering capacity savings (data Response AG 10-7, att). It is not apparent that OG&E is considering energy efficiency based, and thus energy savings based, DSM. An alternate view may have a considerable impact on the company's IRP analysis. Given that OG&E's view is that it has a looming capacity shortfall as well as growing energy requirements (see, e.g., Exhibit JBL-2), the company reasonably could have been expected to take steps to ensure an earlier completion of the current study.

Q. Under current circumstances, would you expect demand-side resources to be increasingly attractive?

A. Absolutely. DSM programs produce a resource providing energy and capacity savings that otherwise must be met through supply-side investments in new resources. The value of demand-side programs, particularly those that focus on capacity savings, can be expected to reach a maximum for a utility that is contemplating major supply-side investments. As the value of DSM programs rise, the investments in those programs can be expected to become increasingly cost-effective. As such, the Commission should send a clear message to OG&E that the Commission expects to see increasing its commitment to demand-side programs as a resource to meet the growing consumer demands for energy and capacity.

Q. Do you see any evidence of an increasing commitment by OG&E to demand-side resources?

A. As is evidenced in IRP Table II-8, OG&E is anticipating no increase in the effects of demand-side resources across the ten-year planning horizon ended 2016. The company states only that the study is underway and should be available "before the end of the year" (IRP at ES-3). The Company has not provided any specifics on the scope of the study nor provided any evidence in this proceeding that potential DSM energy savings or additional demand reducing programs are getting consideration.

Note, for example, that OG&E estimated a "value of DSM" from its PAR model of $[redacted] per kW-year (in $2006; Response to Data Request AG 10-7_Att.). The response also indicates that DSM programs are assumed to produce no energy savings. This demonstrates a very limited view of DSM's potential.

Q. Can you provide an example of more aggressive activity to identify and implement demand-side measures that may serve as benchmarks for OG&E?

A. Yes. The state of Vermont has an annual energy efficiency program budget level of about $30 million. At that funding rate total annual energy savings from the 2007 through 2012 activities could reach 850 GWh out of about 7000 GWh and still growing, or about 125 MW of peak demand reduction. Vermont has less than a 1200 MW total state peak demand. This means they plan to achieve a 12% reduction in energy requirements for their utilities due to cost-effective energy efficiency programs. If by 2012 OG&E could only capture half the opportunities of Vermont on a percentage basis, 6% of OG&E's demand (1,800 GWH, 350 MW), could be eliminated. This alone is the equivalent energy generated by over 200 MW of a base load coal-fired facility. Also, when Connecticut was facing short supplies during the summer of 2004, ISO New England (which is responsible for maintaining the reliability of the bulk power system in that state), determined it should issue an RFP seeking alternate resource proposals. Through this RFP, the level of resources ultimately available to Connecticut during peak conditions increased by roughly 250 MWs, roughly twice the 127 MWs in capacity savings projected by OG&E across the ten-year planning horizon. Note that Connecticut's peak load requirement is of comparable size to that of OG&E. These two are simple examples that benchmarking would produce a substantial inventory of DSM that should be included in the IRP analysis and likely the Company's plans.

Q. What would you expect to see as an outcome of that analysis?

A. First, as I discuss later in this testimony, my evaluation of the PSO DSM program data estimates that there is at least 90 MW of cost effective, using a Total Resource test, of energy saving programs. I would thus expect to see at least 100 MW of energy efficiency DSM programs prove economic on the OG&E system. Of course this estimate is without any specific OG&E program data. Also, since we have seen in this docket alone that the estimated cost of construction of new generation facilities has been increased by [redacted]% by OG&E (Exhibit JGA-3), the value of load curtailment programs must be increasing at least that much. If the amount one can pay for Demand Reducing Load Curtailment participation increases, so should the amount of participation. This is clearly demonstrated by the Connecticut experience. A conservative conclusion would be to expect participation in, and demand reduction effect of, to increase by at least 20%. Therefore I would suggest that another 25 MW of DSM effects would easily prove cost effective and should be included in establishing a view of the timing and magnitude of OG&E's capacity shortfall.

Q. What do you conclude?

A. Even though at this point, OG&E has failed to identify any additional cost effective demand-side resources, I am confident that a substantial reduction to the forecasted retail energy requirements is achievable even within the next 5 years and should be considered in OG&E's resource planning. I would utilize at least 125 MW of peak demand reduction and an energy requirement reduction of 815 GWH as my starting point in determining when the current and committed fleet of supply resources is no longer sufficient to meet required capacity margin levels for OG&E.

Q. What other concerns do you have regarding the range of supply options that was considered by OG&E?

A. OG&E excluded from its analysis of potential resource options purchases from existing (or planned) generating facilities in other parts of the SPP market. OG&E has represented that it plans to explore such opportunities through the RFPs that it will issue (see IRP Table V-1). However, this approach is problematic because the company is beginning to make resource commitments as if no such purchase (or acquisition) options exist.

Q. Do attractive procurement alternatives exist in the SPP market?

A. There are times when generation assets are put up for sale by their owners at below-market prices, because the financial owners can be under pressure of one type or another. This is more likely to occur when markets are in a "surplus" condition such that generation providers must compete vigorously with one another to secure sales opportunities. OG&E has not allowed the choice of surplus capacity purchases to be an option for its 'optimization' process.

Therefore, before OG&E makes any decisions to build new generation, for example, it should be expected to give serious consideration to whether any supplies from other parts of the SPP region could be acquired at lower cost (and recognizing that incremental transmission costs may have to be considered in this analysis). What is now an "unknown" in OG&E's resource planning analysis is whether a resource exists in some other part of the SPP that (with some level of transmission improvements) could cost-effectively serve OG&E's needs for some time into the future.

Q. Has OG&E developed any assessment of the cost-effective potential of distributed generation resources?

A. No. This potentially important source of additional capacity has not been considered in OG&E's IRP model (see the response to Data Request AG 12-13).

Q. In reviewing OG&E's planning models (i.e., CEM and PAR), did you learn of problems in the mechanics/workings of those models?

A. Yes, during the course of the March workshop and in subsequent discussions, several problems with model mechanics came to light.

Q. Please describe those problems.

A. A first problem was discovered related to the way that the McClain facility was depicted in the model. As initially set up, the model outputs were projecting that McClain could be expected to operate at higher capacity factors than coal units that were projected to have notably lower operating costs. This was, of course, a counterfactual result that required subsequent model revisions. The "fix" is documented in the response to Data Request AG 20-1, which states that "the modeling was adjusted so as to require the McClain unit to be run as one unit," whereas previously the McClain facility had been modeled "as two separate units." OG&E states in AG 20-1 that "this change mirrors the historic and expected output of McClain."

Q. Where there other problems with model mechanics?

A. OG&E has worked with our team at La Capra Associates over the last two months to improve the quality of the analysis modeling. La Capra Associates in this review process has acted as a vetting team testing the credibility of the model results. We have had numerous iterations with OG&E's team in a cooperative manner, resulting in several responses to data requests. At this junction we are still communicating with the OG&E team concerns about some aspects of the modeling we see during the vetting role we have ended up providing. An example of this is as follows. A review of the revised model outputs revealed other anomalies in the anticipated dispatch of certain coal based facilities. OG&E staff indicated that a problem resided in modeling assumptions for certain "environmental" costs (e.g., O&M costs to support scrubbers) that had been included in the modeled costs of new coal-fired facilities, but not in the costs of existing coal-fired facilities. OG&E states in its response to Data Request 20-1 that its model was adjusted to reflect the impact on existing OG&E units of the installation of environmental equipment, as proposed by OG&E in its March 30, 2007 filing with the Oklahoma Department of Environmental Quality ("ODEQ") to satisfy Regional Haze requirements. When this change was made the results started indicating that the newer more efficient coal capacity would dispatch before the older more costly coal facilities. This shows the detailed review required and still in process between the La Capra Associates team and OG&E.

Q. Did OG&E's IRP model factor the potential sale of emission allowances into the resource planning process?

A. No (Data Request AG 17-14). Depending on the resource plan selected and the level of emissions allowances consumed under a given expansion plan; the number of emissions allowances consumed will vary. This means that the modeling process was ignoring the different levels of surplus emissions that would be available (e.g., for sale) under different expansion plans. As described in the response to Data Request AG 20-1, OG&E has since introduced modeling changes to reflect emissions costs of each generating unit. This change serves to ensure a consistent treatment of allowances (all of which would remain intact/unused, given the separate tally of emissions costs).

Q. Did you identify any problems with the modeling process as it relates to the interface between the CEM and PAR models?

A. It appears that a substantial problem may reside in the interface between the CEM and PAR models. As explained above, CEM is effective in exploring large numbers of competing resource options across an extended period of time (i.e., the 30-year term of a planning period); however CEM sacrifices a degree of accuracy to achieve this capability. In reviewing output from the CEM and PAR models, I found evidence that the expansion plans that CEM identifies as optimal may not be optimal.

Q. Please explain.

A. As documented in the response to Data Request AG 20-1 (Exhibit JGA-3), the company found it necessary to introduce modeling changes to its CEM and PAR models in response to discussions at the March Workshops. In the response to Data Request AG 20-2, OG&E presents the output of its models which identify a revised Base Case. This revised Base Case indicates that CEM selected Red Rock in 2011 as part of the optimal portfolio (see AG 20-2, Att_1 Supplemental., and line 9 of the generation tab of Att_2).

However, the response to Data Request AG 22-1_Att 3 presents the results of a subsequent set of model runs in which Red Rock was excluded. Setting aside the results of the "Operating Risk" analysis (which are a separate set of calculations performed using PAR that is beyond what is evaluated in CEM), consideration of "Levelized Capital Costs" and "Total Expected Operating Costs" reveal that the "No Red Rock" scenarios actually had lower combined costs when evaluated by the more accurate PAR model. The results cited above from Data Requests AG 20-2 and 22-1 also are presented in Exhibit JGA-7. Since CEM would have had the flexibility to choose resources other than Red Rock in the revised Base Case, the fact that it did choose Red Rock means that CEM failed to identify a resource plan that PAR would determine to be optimal in NPVRR terms.

Q. What are the implications of this evidence that CEM does not always identify the least-cost in the (AG 20 and AG 22) model reruns that you requested?

A. This throws the results presented in Table IV-9 into question. The assertion that Red Rock is a good economic choice because it was chosen by CEM is not backed by analyses using PAR. It seems quite possible that, had the company tested the "optimal" expansion plans identified by the CEM model on a with- and without-Red Rock basis using the more accurate PAR model, it might have provided a true indication of the economics of the Red Rock project.

Q. What is your recommendation?

A. The Commission should not rely on the results of Table IV-9 without further testing. At a minimum, each of the scenarios that include Red Rock as part of the CEM-identified optimal expansion plan should be tested in PAR, without Red Rock available, to ensure that the more accurate PAR model reaches the same conclusion. This additional comparative analysis would show whether there are other expansion strategies for which excluding Red Rock would reduce total costs.

Q. Were there problems with the data used as inputs to the model that supports OG&E's IRP report?

A. Yes, a number of the input values to the IRP were outdated. These included some relatively important inputs, such as the capital costs of key generation options in the model. Many of the input costs in the IRP were based on Burns and McDonnell study that was published on February 2006 (IRP, Appendix H). Based on its analysis of coal and CC costs, OG&E determined that coal would be the most cost-effective option. The input costs for the unit that serves as the proxy in the modeling for the Red Rock facility, the "Super PC-365," had a capital cost (prior to owner's cost) input value of [redacted] per kW (see IRP Table IV 1). This amount is [redacted]% below the $[redacted] per kW that derives from the $[redacted] billion total cost estimate in the September 2006 Sargent and Lundy cost estimate (OCC 1-31). The $[redacted] billion figure corresponds to the amount that OG&E now seeks to have pre-approved (see Langston Direct Testimony at 19). As is indicated in the response to Data Request AG 20-1 (Exhibit JGA-3), it was necessary for the company to increase its assumptions regarding the costs of coal generation facilities by [redacted]%, and combustion turbine and combined cycle facilities by [redacted]%, in order to bring its model inputs up-to-date.

Note that the $[redacted] per kW figure cited above is $[redacted] billion in capital costs, less the total escalation amount identified on the bottom of page 1 of the September 2006 Sargent and Lundy cost estimate, divided by Sargent and Lundy's estimate of the net capacity output. This calculation ensures that my comparison of capital costs included in the IRP to the current estimate is done in 2006 dollars and at net output values, to be consistent with IRP Table IV-1.

Q. What are the implications for the resource plan results?

A. First, the costs of the plan will be higher due to the fact that the costs of the primary supply alternatives are more expensive.

Second, the higher costs would lead to higher prices of electricity. As discussed above, price elasticity effects would reduce the load forecast.

Third, the economics of coal options erodes relative to combined cycle due to the fact that capital costs are a larger fraction of total cost of power for coal facilities. This has the potential to alter the timing of resource additions and the types of resources to be added. The resource planning analysis done for the IRP in 2005 would have a more favorable assessment of the merits of coal relative to other options than an analysis done with the more current cost information.

Q. Did you find problems in the conclusions drawn by the Company from its analyses?

A. Yes. First, OG&E notes at the end of IRP Section IV.B that there is not much disparity in the NPVRR amounts between the scenarios (see IRP Table IV-9), and suggests that this is partly because production costs attributable to the company's existing **6,122** MW supply portfolio are included in the calculation. However, it is likely that the differential between NPVRRs is overstated by these analyses. As circumstances change, in the future, the details of each scenario will change.

The utility is unlikely to remain "locked into" resource procurement strategy that time shows to be unsuitable to circumstances. This means that the differential NPVRRs are overstated as we would expect at some point the resource plans to converge on similar resource additions for the remainder of the study period. I would expect that the NPVRR differentials in any given case (i.e., as listed in IRP Table IV-9) will almost certainly be less than presented. I have concerns about drawing any conclusions from the full array of results shown in that table.

Problems with OG&E's Risk Analysis

Q. Do you see problems with the risk analysis that represented a final step in OG&E's IRP modeling process?

A. As a general matter, I support OG&E's efforts to evaluate the significant risks that may affect the company's resource plan in terms of both costs and benefits that ultimately may accrue to the company and its ratepayers. Moreover, testing potential generation expansion plans under a series of plausible scenarios can provide useful insights into how competing expansion plans may perform over time. However, there are problems with the risk assessments that OG&E performed.

Q. What kinds of problems do you identify?

A. I find two problems. First, OG&E's presentation is deficient because it does not consider the cost and risk performance of the expansion plan that includes the proposed Red Rock facility in relation to the next best expansion plan. As a consequence, even if the CEM modeling is successful in identifying the least-cost expansion plan for a given set of resource assumptions (a premise that is in question, as discussed above), one cannot determine whether the next best resource option would cost only a small increment more (i.e., in NPVRR terms) than the Red Rock proposal. Thus, the as-filed IRP leaves as an unknown the degree to which the Red Rock option outperforms the next best alternative.

A second problem ultimately compounds the first. Specifically, there are significant risks that have not been considered, or not been fully accounted for, in OG&E's analysis. The obvious result here is that the planning process leaves ratepayers exposed to risks that reasonably might be mitigated through the planning process.

The unavoidable consequence of the two problems taken together — failing to explore the costs of the next best option and not considering key risks in the planning process — is that the planning process falls short. Here, because OG&E's IRP did not visibly evaluate the NPVRR cost performance of the next best option, we, and likely the Commission, cannot determine whether any important risks can be avoided at relatively low cost, simply by substituting other resources into the preferred expansion plan.

Q. Can a view of the "next best" expansion plan be developed fairly easily?

A. Yes. This testing readily can be performed (the company already has attempted some in developing its responses to Data Request Set AG 22). This comparative analysis can provide insight into the magnitude of the benefits offered by proposed new resources. Absent an analysis that demonstrates how the next best alternative would perform, the Commission cannot know whether the cost differential between the two options is as little as one dollar. Note that if the cost differential between an expansion plan containing a proposed new resource and the next best option is small, a careful consideration of attendant risks becomes critical.

Q. Have you attempted to evaluate the performance of the "next best" option in your review?

A. I have attempted to have this analysis performed by OG&E, using their models and their latest view of input costs and characteristics. This cooperation has produced some useful information, although as mentioned we are still working iteratively with the Company in that process. The responses to Data Request AG Sets 20 and 22 (Exhibit JGA-7) provide an example of the type of "with" and "without" Red Rock analysis that should be completed if the Commission is to have a complete view of the benefits of one resource option relative to another.

Q. Once a view of the costs of the proposed optimal and next best resource options have been identified, what next?

A. With this foundation, the analysis readily can turn to the risk analysis. As indicated, there are significant risks that have not been considered, or not been fully accounted for, in OG&E's analysis. Note that the analysis I recommend would consider the costs of competing resource options (and/or expansion plans) in NPVRR terms, for example, and then assess those options in relation to different risks presented. This is exactly the approach taken by OG&E in earlier planning processes (see, for example, the "Qualitative Trade off Criteria" presentation that was incorporated into the company's January 21, 2005 Resource Plan Overview, at 16, in CONFIDENTIAL AG 2-2_Att. 1). I find this to be a useful — and intuitive — approach to resource planning.

Q. What risks does OG&E focus on in its risk analysis?

A. The "key" risks in OG&E's IRP identified in Section IV.C.2 of the IRP as follows:

- Short-term volatility in retail loads driven by weather conditions;
- Uncertainty in the long-term growth in demand for electricity, which is driven by long-term economic factors;
- Uncertainty in the price of power generation fuels, primarily natural gas and coal;
- Future environmental regulations; and
- Capital cost risk (which the company considers outside of its PAR model).

Q. Are these valid risks?

A. Yes, but its true key risks should be defined somewhat differently. Some risks in the company's list may fall short of qualifying as "key" risks. For example, OG&E has not made a case that short-term load volatility presents it with any unusual risks (nor has it made the case why a substantial investment in base load coal option would improve its position in this regard). By contrast, OG&E's analysis does not include several substantial risks that the Red Rock project would present to itself and its ratepayers. For example, the company's analysis does not consider the financial stress that a substantial base load generation investment would introduce in relation to the extensive capital additions program that the company is otherwise proposing (see Motley Direct Testimony at 10-11).

Q. What risks do you see as paramount for OG&E from the standpoint of resource planning?

A. Based on the information available to me through this proceeding, I would summarize the key risks to the company and its ratepayers as follows:

- Fuel price risk (as OG&E has suggested);

- Risk resulting from future environmental regulations (as OG&E has suggested);
- Capital cost escalation risk;
- Financial risk related to unanticipated transmission /bulk power system investments to meet NERC reliability standards;
- Financial risk related to OG&E's anticipated capital investment program; and
- Rate impact risks.

Q. Please explain your view of the fuel price risk to which OG&E is exposed.

A. I agree with OG&E's view that fuel price risk should be a substantial factor in its resource planning process. However, given the recent experience in coal prices (cite), and the potential for substantial increases in the demand for coal nationally and internationally as more generation suppliers consider new coal-based facilities, I have concerns with the limited prices explored by the company in Section IV of the IRP.

Q. Please explain your view of the degree to which OG&E is exposed to risks from future environmental regulations.

A. I agree with OG&E's view that future environmental regulations pose a risk. However, I am concerned that OG&E's analysis of environmental risk, and in particular the risk from potential CO2 regulation, may be understated. As we understand it, the updated runs of the PAR model assume a tax of roughly one half the highest estimate cost by CERA for each ton of carbon emitted. The risk values calculated through PAR are well below this amount. This may not give a true picture of the risk involved. According to CERA, the peak exposure could be nearly double the sum total of the "cost" and "risk" figures presented in OG&E's PAR analysis. Moreover, the CERA number is considerably smaller than a number of carbon cost estimates with which I am familiar.

Q. Please explain your view of capital cost escalation risk.

A. Major investments in new generation always carry some risk that capital costs may increase beyond levels anticipated at the time that investment decisions are made. Depending on circumstances, this risk can be important. I understand that OG&E has incorporated this risk into its analysis of resource options. The response to data requests in Sets AG 20 and 22 provide, for example, summaries of fuel, SO_2, NO_x, CO_2, and "other" risk calculations. However, as of this writing it is not clear how the dollar amount that OG&E attributes to these risk factors were calculated.

Q. Please explain your view of the degree to which OG&E is exposed to risks from system improvements to ensure system reliability, in response to the Red Rock facility.

A. This is a risk that may be substantial. The company asserts that its 12% capacity reserve margin will not be affected by the introduction of the Red Rock facility (see AG 17-4; check). OG&E does not anticipate contingency analyses that might identify other reliability risks associated with adding such a large facility (see AG 7-11). However, this new unit will be the largest on the Oklahoma bulk power system. As such, it is quite possible that SPP will require system improvements to ensure that system reliability is not compromised. In other power systems, I have observed that supplemental generating capacity (i.e., in addition to the first new generating unit) can be required to ensure system reliability under contingency situations. It is normal for reserve requirements to take into account the largest unit on a system.

Q. Please explain your view of the financial risk related to OG&E's anticipated capital investment program.

A. This appears a major problem. OG&E has indicated that it plans to pursue a $[redacted] construction initiative. Because of the potential financial impacts of this initiative, the company has proposed to implement its Red Rock Construction Rider (RRCR). Essentially this means that the Red Rock facility is introducing a measure of financial risk that the company feels compelled to address. OG&E, however, has indicated that there were not even communications between those responsible for resource planning and those responsible for capital planning generally to determine if resource planning strategies could be implemented to mitigate the risks presented by the overall capital planning program. This financial risk is one that should be considered in the resource planning process.

Q. What is your view of the rate impact risks that merit consideration in OG&E's resource planning process?

A. Rate impacts are often a consideration in resource planning processes. In this instance, the company is proposing its RRCR in order to mitigate the rate impacts that it suggests may accompany the commercial operation of the Red Rock facility. The risk that rate impacts may approach unacceptably high levels is one that should be factored into OG&E's resource planning process.

Q. Does OG&E's risk analysis incorporate all of these significant risks?

A. No, it does not. While the list that I present is not intended to be all-inclusive, it does reveal some important limitations in the company's risk analysis. As a consequence, the results of OG&E's planning process are in question.

Q. Has OG&E introduced improvements to its resource planning models to address some of the deficiencies that you have previously identified?

A. Yes it did. Changes to the CEM and PAR models were introduced in order to address a number of significant problems were completed several weeks ago on April 13, 2007, with the submittal of OG&E's response to Data Request AG 20 (Exhibit JGA-3).

Q. Do OG&E's recent modifications to its resource planning models remedy all of the problems that you discuss above?

A. The changes that OG&E has recently introduced appear to have remedied a number of problems in its planning models. However, some remain that cause concern.

Q. Which problems remain?

A. The remaining problems may be summarized as follows:

- The range of resources considered in OG&E's resource planning processes is still overly constrained. Notably, the capacity savings that could result from embracing demand-side opportunities with greater enthusiasm are still not incorporated into the company's need analysis and planning models. Moreover, potentially cost-effective procurements from suppliers elsewhere in SPP still are not considered;
- I have continuing concerns that the company's models still are not accurately defining the optimal expansion plans for a given set of scenario planning conditions;
- The interpretations applied to model outputs still can be distorted because the NPVRRs presented in recent model "reruns" reflect costs of expansion plans that optimized relative to varying input assumptions, then "locked in" as each new expansion plan is tested under base case conditions. The Base Case scenario presented still suffers from implicit deficiencies (e.g., the load forecast is problematic). Moreover, the alternate scenarios that they present (i.e., in the response to Data Request AG 20-2) are unrealistic in that they assume continued build out

across 30 years of alternate expansion plans that would be known to be faulty after only a few years. In short, they depict the results of expansion plans that would never be implemented, and compare those results to OG&E's proposed base case expansion plan. As before, this approach makes no allowance for modifications to bring a given expansion plan into line with the emerging reality. Consequently, the NPVRR costs likely are overstated.

- OG&E's approach still offers only limited perspective on how the "next best" option to Red Rock would perform.

- All of the dominant risks that confront OG&E still are not considered in the recommendations that OG&E has developed, including some that could alter the company's view of the optimal resource plan.

IV. SPECIFIC ISSUES WITH PSO's IRP ANALYSIS

In this section of my testimony, I will review specific areas of PSO's 2005 Integrated Resource Plan ("2005 IRP") and 2006 Integrated Resource Plan ("2006 IRP") and the associated testimony of Mr. Stuart Solomon, Mr. Scott Weaver, Mr. Timothy Hostetler, and Mr. George Fitzpatrick filed in this Cause in December 2005, February 2006 and July 2006.

Q. Please summarize your findings with respect to PSO's 2005 IRP and 2006 IRP?

A. In my review, I found that:

1) PSO has proposed an integrated resource plan which generally conforms to proper planning elements to be considered in determining the need for new resources;

2) PSO's energy and capacity requirements assessment is highly dependent upon its forecast of future system loads. This forecast is not a sufficient basis for pre-approval of the requested base load capacity due to:

   i. The lack of assessment of the uncertainties in the forecasted energy requirements and peak demand;

   ii. The limited consideration of demand side management and demand response programs to mitigate the growth in demand;

   iii. The limitations in the derivation of peak load projections from an energy forecast method;

   iv. The more recent, lower peak load forecast produced in "2006 IRP".

3) PSO's options screening precludes direct comparative analysis of demand side measures with supply options. The DSM measures considered were pre-screened as not beneficial based upon a rate impact basis and not included in the Strategist analysis using a revenue requirement screening test.

4) PSO's analysis of energy and capacity requirements are based on an assumption that no power imports are available from affiliates (SWPECO or AEP East) or the SPP market. PSO's recommendation assumes full build out of capacity in PSO's system by 2008 sufficient to meet some of today's energy requirements and the growth in energy requirements, as well as 100 percent of PSO's forecasted capacity margin requirement, with local generation.

5) PSO's economic analysis seeks to minimize long term present value of revenue requirements (25 years). PSO has not prepared an annual forecast of near term revenue requirements or rate impacts of its proposed plan. Given the capital-

intensive nature of base load capacity additions, the now terminated Lawton facility, and the addition of [redacted] MW of peaking generation, the near-term rate impacts of these collective additions should be assessed.

6) PSO has conducted uncertainty analysis with respect to its natural gas price forecast, but not with respect to the forecast of energy requirements, including peak demand, or to changing environmental regulations.

Q. What changes or supplements to the PSO IRP analysis do you believe will allow a more precise viewpoint to develop on the overall economics of the proposed Red Rock project?

A. I recommend that PSO should, in order to remove doubts about its IRP analyses and recommendations,

i. conduct a comprehensive assessment of the potential for energy efficiency, demand side management, and demand response programs with lower overall revenue requirements;

ii. demonstrate that its revisions to their Energy and Peak Demand forecasting methodology are producing a reasonable hourly demand forecast, as well as incorporating alternative forecasts as either sensitivities or scenarios;

iii. conduct an assessment of the firm transfer limits between PSO and other SPP systems be conducted to define the potential for purchase of firm capacity in the SPP market from other sources, considering planned transmission upgrades included in SPP's system plan; and

iv. provide an updated IRP analysis reflecting the power plant costs and characteristic information now available as a result of the Red Rock project cost estimations that is now being requested as Used and Useful.

Q. What planning process did PSO use in developing its recommendation on the need for capacity?

A. PSO prepared its "2005 Integrated Resource Plan" in the Spring of 2005 and initially relied on this planning process as the basis for its recommendation. The 2005 IRP included a 7-step planning process. A similar process was used in the 2006 IRP. This includes a forecast of loads and reserve requirements, assessment of existing and new resource options, and an analysis of the economics of those options. I will provide my comments on each of the seven steps and PSO's assessment in each step in a moment.

PSO has developed a ten year schedule of capacity additions based on a 25-year planning analysis. The decisions at issue in the planning process are those that will result in the next capacity additions in the next several years. However, the longer term analysis is necessary to reasonably address the long term economics of long-lived generation investments being considered. PSO has conducted this long term assessment by evaluating alternative supply plans with the objective of minimizing the cumulative present value of revenue requirements over a 25 year period.

This Process was updated in the Spring of 2006 and filed as part of the testimony of Scott Weaver.

Q. Is PSO's resource planning process a reasonable one?

A. This process is consistent with the process used by most utilities in preparing a long term resource plan and is a constructive framework. This is a reasonable framework for this effort. I have a number of specific concerns or suggestions in each of the seven steps, but the overall process is a reasonable one in most respects.

One notable limitation of PSO's framework is the absence of any consideration of shorter term rate impacts. The process should include an analysis of the annual revenue requirements of the final plan to assure that the plan meets near term rate objectives as well as long term economic objectives.

A. PSO's IRP Process

Q. Please describe the specific comments you have regarding the seven steps of the PSO planning process.

A. My specific comments on PSO's approach to each of the seven steps are provided in sequence below. In later sections of my testimony, I describe specific issues that affect the results of this process.

<u>1. PSO's Load Forecasting Methodology and Results</u>

Q. Please describe the load forecasting method used by PSO.

A. PSO's forecast of electric energy and peak demand used in the 2005 IRP and in the economic analysis used in the determination of need for peaking capacity was prepared in the summer of 2004. At that time, the forecasting methodology used to prepare the forecast was econometric.[1]

The first step in the forecast development is an econometric forecast of energy sales by customer class. This energy sales forecast uses historical data and economic and

[1] PSO's summer 2004 forecasting method is described in its 2005 IRP documents on pages 8 through 11. More recently, the PSO forecast has included elements of end use forecasting methods, as well.

demographic forecasts as inputs. Econometric modeling of this type is commonly used in the industry for energy sales forecasts in situations where the economy and population are expected to be the primary determinants of energy consumption. End use models are used in situations where significant shifts in the types of end uses are anticipated relative to historical consumption.

This sales forecast is converted to a forecast of energy requirements of the generation system by adding in an estimate of losses in the transmission system.

PSO's peak load forecast is derived from this energy forecast and historical relationships between energy requirements and peak demand. In effect, the ratio of peak demand to energy requirements, the system load factor, is held constant over the forecast period. Thus, the peak demand forecast growth rate tracks the energy requirements forecast.

Q. Do you have any concerns with the load forecasting methodology utilized by PSO in their application in this Cause?

A. Yes. I am concerned that the uncertainty in energy and peak demand forecasts was not assessed in the 2005 IRP or the 2006 IRP. There are many important uncertainties in load forecasting and load is commonly a key uncertainty addressed in resource planning studies. In the context of this Cause, determining the need for additional energy serving resources, the uncertainty in the forecast of energy requirements and peak demand is very important, more so than uncertainty in fuel prices which were the primary sensitivity variable examined in the economic assessments conducted by PSO.

Q. What are the implications of these load forecasting methodology concerns for the determination of peaking capacity requirements in this Cause?

A. It is important to recognize the limitations of the forecast, particularly the energy and peak load forecast, in making determinations for pre-approval of investments in peaking capacity. In effect, PSO is asking the Commission to bet on this peak load forecast in this Cause. Given the significance that the load growth has in the recommendation that PSO has put forward, the information provided on the forecast of energy and peak demand and its uncertainty is very limited.

2. *Review and Assessment of Current Generation Resources*

Q. Please describe PSO's review and assessment of its current resources.

A. In this step of the process, PSO makes assessments about the ability of its existing generating units to economically provide capacity in the future. In concept, this review considers the ongoing costs to maintain the unit in active service through the planning period relative to market capacity alternatives. Alternatives to continued operation include retirement, mothballing, life-extension or repowering of the assets.

For the 2005 IRP and 2006 IRP, PSO review included a screening of its units leading to more formal assessments of Southwestern Units 1 & 2 and Tulsa Unit 3. Mr. Weaver describes this in his Direct Testimony as a "Disposition Review" (pages 21 – 23). PSO concluded that the Southwestern Units were suitable for continued operation through the planning period. It concluded that investments in upgrades to [redacted] were warranted to restore that unit's ability to start and operate at a rating of [redacted] MW.

With the upgrades to [redacted], PSO's 2005 IRP and 2006 IRP assumed that all existing generating units remain in service throughout the planning period at current ratings.

Q. What aspects of this assessment are relevant to the determination of the need for capacity?

A. This assessment is important to the determination of the need for particular capacity, in light of the fact that PSO's generation fleet includes substantial amounts of older gas and oil fired capacity. More than 2[redacted] MW (nearly [redacted] percent of PSO's total capacity) resides in oil and gas fired units that are at least 30 years old.[2] A resource planning analysis for a system of this type must consider the longer term physical, economic, and environmental viability of these assets. This would include both the possibility that some units may not be viable longer term and may need to be removed from service and the possibility of life extensions or repowerings for these units at costs below that of new sources. PSO's recent repowering of Northeastern Unit 1 is an example of this type of investment that expanded the unit's capacity and improved its efficiency. To the extent that such investments in these older units are feasible and cost effective, they should be considered as part of the resource planning process.

Q. Do you have any concerns with PSO's assessment of its current generation?

A. Yes, I am concerned that PSO has not conducted any formal study of life extension or repowering options of any of its aging gas-fired steam units. PSO has indicated that no studies of this type have been done for the 2005 IRP and have not been conducted at any time in the recent past. Apparently, the Northeastern Unit 1 repowering is the last such study conducted. The Disposition Review described by Mr. Weaver was much more limited in scope.[3]

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[2] The PSO units and their ages are listed in Exhibit SCW-6 included in the Direct Testimony of Scott Weaver.

[3] Supplemental Testimony of Mr. Scott Weaver p 27-29

PSO prepared the 2005 IRP and 2006 IRP without a formal long term assessment of the optimal use of these older generating assets. While it is unlikely that repowering would be justified solely on a capacity basis (reduced energy production costs would also be an important consideration), these options should be examined and, if feasible, considered as part of the resource planning process just as investment in new peaking capacity is considered.

3. Reliability Analysis/Reserve Criteria

Q. Please describe PSO's reliability analysis and reserve criteria.

A. PSO's 2005 IRP and 2006 IRP utilize the SPP minimum requirements for capacity margin of 12 percent, which is equivalent to a reserve margin of 13.6 percent of PSO's peak load. This reserve requirement is a long standing SPP criterion that PSO has used in its planning. PSO must have installed generation capacity and firm purchase commitments equal to 113.6 percent of peak load to meet this requirement.

In the 2005 IRP and 2006 IRP, PSO has assumed that this requirement will be met with generation within PSO's system. Mr. Timothy Hostetler indicates that the SPP system has become congested, allowing little opportunity to obtain available transfer capability (ATC) over the transmission system to buy or sell capacity. This assumption does not alter the SPP reserve criterion, but it does restrict the ability of firm capacity purchases from sellers in the SPP region to contribute to PSO's plans to meet that criterion.

Q. What aspects of this assessment are relevant to the determination of the need for capacity?

A. The reserve requirements have a very direct bearing on the need for additional capacity. Peak load plus required reserves is the criterion that each utility in SPP must meet to assure adequate supplies of generation for system reliability.

The transfer capacity limitations have a direct impact on PSO's need for capacity in that it restricts the sources of capacity that can be considered to meet PSO's reserve requirement. Mr. Hostetler indicates that PSO cannot rely on firm capacity from SWEPCO, AEP-East, or other SSP suppliers due to these limitations and, therefore, the peaking capacity requirement becomes localized to PSO's system. This is significant due to the fact that PSO has, in recent history, relied on firm capacity imports from the surplus SPP market.[4]

Q. Do you have any concerns regarding reliability analysis and reserve criteria?

A. I do not have a concern with the reserve margin requirement, as that is consistent with SPP's requirements and that standard has been used for some time by SPP and the Oklahoma utilities.

However, the transmission congestion and transfer capacity limitations are an issue that is new for PSO and is a substantial change from PSO's prior resource plans.

Q. Do you have any other concerns about the reliability impacts of resource capacity?

A. The IRP analysis performed by PSO does not evaluate the impact of increasing the largest sized capacity unit on the system. Normally increasing the size of the largest

[4] See Myron D. Adams Responsive testimony in Cause No. PUO 200200038 (November 5, 2002) at p 8-15

contingency would tend to increase the Operating Reserve requirements. The increase in operating reserve required by a large, 900 MW class unit is provided either by the allocation of some amount of existing capacity toward supplying this duty or from quick start capacity such as aero derivative combustion turbines. In either event there is likely to be an increase in costs associated with a 350 MW increase in the largest contingency. If it required additional aero-derivative combustion turbine capacity the investment could be between $150 and $200 million dollars. That has not been discussed in any PSO or OG&E analyses.

4. <u>Determination of Adequacy of Current Resources/Need for Additional Resources</u>

Q. What is your viewpoint regarding the timing of when PSO's existing resources will no longer provide sufficient capacity to meet the requirements set forth by SPP?

A. In JGA-4 I have prepared our analysis of the Capacity, Demand and Reserve requirements (CDR). This CDR is in similar format to those provided in the testimony of Scott C. Weaver. This CDR shows the timing of need for capacity, given the expiration of contracts with other suppliers, including affiliates, new demand forecasts, and reflects the settlement in the peaking case whereby the Lawton Cogeneration contract is terminated and the parties agreed to let PSO proceed with the installation of peaking capacity. In JGA-4 we see that the existing resources are unable to satisfy PSO's capacity requirements in [redacted]. By [redacted], the Company is deficient by between [redacted] MW and [redacted] MW.

5. Identification of Capacity Resource Options

Q. How extensive was PSO's list of resources either in generation or demand management resources?

A. PSO developed cost and performance characteristics for many configurations of simple cycle combustion turbines for peaking duty, several configurations of combined cycles for intermediate duty and a full array of coal fired generation capacity for base load duty. I would note that there is no incorporation of renewable generation options beyond current capacity. Also, in the PSO IRP screening process each of these duty cycle types, i.e. Combustion Turbine versus Combustion Turbine, are part of the supply screen process using bus bar costs on a $ per kilowatt-year basis (Weaver Supplemental Exhibit SCW -10)

Q. Did PSO develop an extensive set of DSM programs also?

A. Yes within the materials PSO supplied (worksheet of George Fitzpatrick, AEP DSM Evaluation_v1-PSO) we see a large number of programs to stimulate and create incentives for energy efficient equipment utilization within the residential and commercial customer classes.

Q. If PSO developed an extensive set of DSM programs options why there are no DSM programs included in the resource plans?

A. PSO has screened out the resource potential of DSM utilizing a Rate Impact Measure within the Demand Program screening process, which I will discuss later on in this testimony in detail.

6. ***Determination of Optimal Resource Mix and Timing***

Q. How does PSO determine its Optimum Resource Mix?

A. PSO utilizes the commercial model *Strategist* to evaluate the total cost of a resource portfolio as a Net Present Value (NPV) over 25 years. This model includes capacity related costs such as carrying charges, to recover return of and return on investments, fixed O&M and taxes. In addition the production costs are estimates capturing the dispatch of the full PSO system of resources, their fuel usage and expenditures, variable O&M costs, the cost of environment emission allowances consumed and economy interchanges for purchases and sales with neighboring utility systems. PSO finds five resource plans where the plan was optimized for a particular fuel price forecast. After finding these all are then simulated under all five fuel price forecast scenarios. These plans are then compared for overall economics and robustness under these variations in fuel price futures,

Q. Are the other aspects of analysis you would expect a company to include in its IRP analyses?

A. Yes. This analysis focuses solely on 25 year NPV costs using levelized carrying costs in its analysis. This work would be more informative if in addition the company modeled the annual revenue requirements. This would give indications of rate impacts in the short term for different plans, which would be informative regarding the potential financial feasibility of each of the resource plans.

Also the IRP would be enhanced with some analysis of the uncertainties regarding load growth, environmental regulations and their cost implications, and installed capital cost. In addition some degree of integration of transmission planning, rather than the infinite bus analysis would provide additional guidance for the resource procurement steps.

7. *Implementation Considerations*

Q. Does PSO's IRP give proper consideration to implementation issues of the identified and recommended generation resources?

A. Actually very little if any consideration of the actual implementation is included in the generation planning exercise that PSO has performed under the IRP analysis. IRP is silent on locational issues for resources to capture transmission cost minimization or reliability maximization.

B. PSO's 2006 IRP is Remains Void of New Demand Management Resources

Q. Have you found any differences regarding Demand-Side Management resources between the IRP results updated for 2006 and the original filing of the 2005 IRP analysis?

A. No. Both plans fail to include economic DSM programs that the Company identified as having potential.

Q. Please summarize your findings with respect to Demand-side Management resources within PSO's 2005 IRP?

A. I did extensive analysis on the economics of the programs that PSO developed and 'tested' in its screening process and found that PSO's analysis was flawed. In my review of PSO's DSM analyses and data, I found that:

1) A more appropriate analysis of the data demonstrates a potential for around 736 GWH of energy savings and 500 MW of additional annual peak load reduction;

2) A determination of the economics of PSO's DSM programs' design using a Total Resource Test would have resulted in significant energy requirement reductions as well as a reduction in peak;

3) While PSO has developed extensive DSM program options for its integrated resource planning analysis, demand management is not integrated into PSO's IRP analysis. DSM is not actually treated as a resource option alternative to new generation;

4) The DSM forecast included in the IRP plan which serves as the basis for analysis was limited to only 7 MW based on PSO's screening out of most DSM measures. Our independent analysis shows the potential for about 2,000 GWH of energy savings and 500 MW of additional annual peak load reduction if PSO were to use a pure "Utility Cost" or revenue requirements test.

Q. Please summarize what you did to produce an alternative estimate of cost-effective Demand-side Management resources.

A. I have prepared a quick analysis of the potential impacts of making several changes to the DSM program in a cumulative sequence. These analyses were conducted solely by adjusting assumptions and evaluation statistics within the DSM Evaluation Spreadsheet model proved by the Company in this proceeding.[5] The adjustments included:

i. Utilizing the economic criteria to a "Utility Cost" (UC) or revenue requirements minimization test rather than the rate impact test used by the Company;

[5] My review of the limited information on the actual DSM screening activity consisted of reviewing the program spreadsheet model provided the work papers of George Fitzpatrick. The Company did not have a report describing all the programmatic assumptions made by during the DSM screening efforts it conducted and which were conducted on its behalf.