BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF COLORADO

IN THE MATTER OF THE	)	
APPLICATION OF PUBLIC	)	
SERVICE COMPANY OF	)	DOCKET NO. 11A-869E
COLORADO FOR APPROVAL	)	
OF ITS 2011 ELECTRIC	)	
RESOURCE PLAN	)	

ANSWER TESTIMONY

OF

WILLIAM A. MONSEN

On Behalf of

Colorado Independent Energy Association,
Colorado Energy Consumers and
Thermo Power & Electric LLC

June 4, 2012

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1. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William A. Monsen. I am a Principal and Executive Vice-President at MRW & Associates, LLC (MRW). My business address is 1814 Franklin Street, Suite 720, Oakland, California.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I have been an energy consultant with MRW since 1989. During that time, I have assisted independent power producers, electric consumers, financial institutions, and regulatory agencies with issues related to power project development, project valuation, purchasing electricity, and regulatory matters. I have directed or worked on projects in a number of states and regions in the United States, including Colorado, California, New England, Wisconsin, and Nevada. Prior to joining MRW, I worked at Pacific Gas and Electric Company (PG&E). At PG&E, I held a number of positions related to energy conservation, forecasting, electric resource planning, and corporate planning. I hold a Bachelor of Science degree in engineering physics from the University of California at Berkeley and a Master of Science degree in mechanical engineering from the University of Wisconsin-Madison. Additional information about my qualifications is provided in Attachment A.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am submitting testimony on behalf of the Colorado Independent Energy Association (CIEA), Colorado Energy Consumers (CEC), and Thermo Power & Electric LLC (Thermo Power).

Q. WHAT ARE THESE PARTIES' INTERESTS IN THIS PROCEEDING?

A. CIEA is a non-profit corporation and trade association of independent power producers (IPPs). CIEA's mission is to foster competitive acquisition of cost-effective resources for the benefit of its members and Colorado ratepayers. Thermo Power, a CIEA member, holds a PPA with the Public Service Company of Colorado (PSCo) that will expire in 2013. Along with other CIEA members, Thermo Power is a likely entrant into PSCo's next All-Source Solicitation. Thermo Power and CIEA accordingly have strong interests in the bid evaluation issues in this proceeding.

CEC is an unincorporated association of energy consumers that purchase electricity and related services from PSCo. CEC also has an interest in PSCo's power solicitations ("requests for proposals" or RFPs), given that future generation resources that PSCo will acquire will determine associated costs to CEC members and other ratepayers.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses refinements to the bid evaluation process, particularly weighing competing bids between utility-owned generation (UOG) and power purchase agreements (PPAs). CIEA members, Thermo Power, and CEC share an interest in ensuring that bids to sell power to PSCo are evaluated in a fair manner and that the selected bid represents the best option for PSCo ratepayers.

My testimony also addresses other PSCo proposals that could put IPPs at a disadvantage relative to UOG projects. In particular, my testimony addresses PSCo's contingency plans for procuring renewable resources in the event of a capacity shortfall, proposed changes to the accounting treatment of PPAs, PSCo's communication with IPPs that submit bids into its power solicitations, and potential financing restrictions in PSCo's model PPA.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My recommendations are as follows:

1. The Commission should require PSCo to use competitive solicitations if it decides to make "opportunistic" resource acquisitions outside of the Electric Resource Plan (ERP) process;
2. IPP contract terms must be appropriately considered in the bid evaluations. To do so, PSCo should change its approach for assessing the true cost of IPP resources over the life of those assets;
3. UOG projects should not be allowed to compete with IPP projects in PSCo's power solicitations and should be allowed only in the case of an RFP failure, especially in this case where there is a wide range of IPPs to meet forecast needs for capacity during the life of this ERP;
4. If a UOG project is built, then rate recovery for the first ten years of the project's life should be set based on the cost and performance assumptions used in its competitive bid or Commission application for the project;
5. If the Commission does not adopt my recommendation to hold UOG projects to their bid cost and operational characteristics for the first ten years of plant

operations, then the evaluation of bids for UOG and IPP resources should account for the differential in ratepayer risk between UOG and IPP projects;

6. PSCo should be required to procure all resources, including contingency alternatives, on a competitive basis;
7. The Commission should not penalize IPPs for unknown or potential lease accounting standards which may or may not be issued;
8. The Commission should require PSCo to submit an application that specifies in detail how PSCo plans to apply any new lease accounting standards in its evaluation of PPAs;
9. To fully implement the Legislature's expressed desire to ensure transparency and accuracy in bid evaluation, bidders should be given an opportunity to correct potential errors in assumptions proposed to be used by PSCo in bid evaluations prior to a final decision on whether the bid should pass the initial screening; and
10. PSCo should not be allowed to impose unnecessary PPA limitations that have the effect of reducing competition.

2. A VIBRANT INDEPENDENT POWER SECTOR BENEFITS COLORADO

Q. WHAT ARE UOG PROJECTS?

A. UOG projects are power projects that are owned by PSCo. These projects are part of PSCo's rate base. PSCo earns a rate of return on the undepreciated book value of UOG projects. These projects can have book lives of 30 years or more.

Q. ARE THERE DIFFERENT TYPES OF UOG PROJECTS?

A. Yes. There are a number of different types of project structures that ultimately result in utility-owned generation. These include Purchase and Sale Agreement (PSA) offers (where the potential counterparty is responsible for developing, permitting, constructing, testing, and completing the facility, which is then handed over to the IOU), Engineering, Procurement, and Construction (EPC) offers (in which the IOU develops and permits the facility, while the potential counterparty is responsible for constructing the facility), and utility development offers (in which the IOU develops, permits, and constructs the facility). There are also hybrids of these three basic types of projects. For the purposes of this testimony, I refer to all of these potential projects as UOG projects.

Q. WHAT ARE IPP PROJECTS?

A. IPP projects are power projects developed, owned, and operated by non-utility entities. IPPs sell some or all of their output to an offtaker (typically a utility) pursuant to a Power Purchase Agreement (PPA). Different PPAs can have different durations. However, for a PPA with a new IPP project, a PPA typically has a term of 10-25 years.

Q. DOES THE PRESENCE OF AN INDEPENDENT POWER INDUSTRY BENEFIT ELECTRIC CUSTOMERS OF COLORADO?

A. Yes. IPPs provide numerous benefits to Colorado. Aside from placing competitive pressure on UOG projects, IPPs provide other benefits to ratepayers. IPPs have been early adopters of new generation technology. They have been responsible for the development of renewable energy resources brought online in Colorado in the last ten years. They have also led the way in technological advances in fossil-fuel power generation by development of more efficient combustion turbine and cogeneration technologies. Additionally, they were the first entities to develop and build power stations based on high-efficiency aeroderivative gas turbines; these turbines are now commonplace.

Q. HOW HAVE IPPS EXERTED PRICE PRESSURE ON INVESTOR-OWNED UTILITIES (IOUS)?

A. IPPs have competed head-to-head with power projects proposed by the IOUs. As a result, they have acted as a check on costs of UOG projects (just as projects developed by IOUs can potentially discipline the IPP sector of the generation market).

Q. WILL IPPS EXERT PRICE PRESSURE ON IOUS IF BOTH UOG AND IPP PROJECTS ARE BID INTO THE RFPS RESULTING FROM THIS PROCEEDING?

A. Yes, assuming that the UOG and IPP projects are compared under a fair set of evaluation protocols. However, there are certain aspects of PSCo's that might be anti-competitive.

Q. WHAT PSCO PROPOSAL MIGHT BE ANTI-COMPETITIVE?

A. PSCo states that it may be necessary or advantageous for PSCo to make "opportunistic" acquisitions of renewable resources outside of the ERP process.[1] It is not clear how PSCo might procure these resources. If PSCo's own resources are used by default as the backstop resource, this would be anti-competitive.

[1] PSCo 2011 Electric Resource Plan (ERP), Volume 1, page 1-44.

Q. WHAT DO YOU RECOMMEND?

A. The Commission should ensure that PSCo uses a competitive solicitation process to select the best "opportunistic" renewable resource purchases. This will ensure that Colorado ratepayers receive the lowest-cost resource consistent with performance requirements.

Q. ARE THERE OTHER BENEFITS THAT IPPS PROVIDE TO COLORADO?

A. Yes. IPPs have invested more than $3 billion in Colorado, they employ more than 1,500 people, and they contribute substantial amounts to state and local coffers through sales and use taxes.

Q. GIVEN ALL OF THESE BENEFITS, HAS THE IPP INDUSTRY BEEN GROWING IN COLORADO?

A. No. In fact, over the past few years the IPP industry has been losing market share in Colorado. At one time, IPPs provided approximately 3,100 MW of generating capacity in the state, representing approximately 53 percent of PSCo's generation during peak periods. However, this amount has recently been reduced to only about 1/3 of PSCo's electricity generation capacity due to PSCo's addition of it Comanche coal plant as a UOG plant on a non-competitive basis, as well as its recent acquisition of Calpine's generating units in Colorado.[2] In its deliberations in this docket, the Commission should take into account how far the pendulum has swung in PSCo's favor in terms of its

[2] The Calpine units were owned and operated by Calpine, one of the major IPPs in the U.S. The fact that the market share for IPPs in Colorado has declined should not be integrated as a problem with IPP's or IPP resources, but rather an indication of the attractiveness of IPP resources, even to IOUs.

generation market share and should strive to bring PSCo's generation portfolio back into a better balance for Colorado and PSCo's ratepayers.

3. COMPETITIVE RFPS SHOULD BE NON-DISCRIMINATORY

Q. ARE PROPOSALS FOR UOG AND IPP PROJECTS COMPARED SIDE-BY-SIDE IN PSCO'S BID EVALUATIONS?

A. They can be. If PSCo submits a proposal for a UOG project in response to its own RFP, PSCo will evaluate its proposed UOG project alongside IPP project bids. PSCo states that it does intend to submit bids for UOG projects into the RFP that is approved through this proceeding.[3]

Q. HOW DO RATEPAYERS BENEFIT FROM HAVING IPP PROJECTS BID INTO PSCO'S RFPS?

A. Some of the ratepayer benefits of competition were discussed above. In addition, David Svanda addressed this issue in depth in his testimony on behalf of CIEA in PSCo's 2007 ERP proceeding.[4] As part of this discussion, he cited five benefits of competitive electricity supply procurement as outlined by the Electric Power Supply Association:

1. With competition in wholesale power markets the established "law of the land," policymakers have new procurement choices beyond utility-owned generation.
2. A comprehensive, robust competitive procurement is the only way to ensure that customers get the best possible deal on electricity in terms of risk, reliability and environmental performance.

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[3] PSCo 2011 ERP, Volume 1, page 1-46.
[4] Testimony of David A Svanda on Behalf of CIEA in Docket No. 07A-447E, April 2008, pages 16 and 17, as presented in Attachment B.

3. A fair, accurate and transparent competitive solicitation process is an important tool at both the state and federal levels for determining the prudence of utility power purchase and investment decisions.

4. Competitive procurement provides a market test to assess any utility proposal to build its own generation on a cost-plus basis.

5. Competitive suppliers build new plants largely at their own risk and expense, shifting risks away from captive utility ratepayers.

Q. IS PSCO'S COMPETITIVE SOLICITATION PROCESS "FAIR, ACCURATE AND TRANSPARENT"?

A. No. UOG projects often receive explicit or implicit advantages in the bid evaluation process relative to bids for PPAs with projects owned or operated by IPPs.

Q. WHY DOES IT MATTER THAT UTILITY AND IPP PROJECTS PRESENTLY DO NOT COMPETE ON EQUAL FOOTING?

A. IPPs and the financing institutions that support them have limited opportunities to enter the Colorado energy markets. If these market participants perceive that there is not fair competition between UOG and IPPs because of inherent bias in the scheme used by PSCo to evaluate bids, there is a chance that some of these entities might choose to forego participation in PSCo solicitations. This might occur because of the high costs to successfully develop IPP projects. If a procurement process is not transparent and believed to be fair, then developers may choose to deploy their resources (e.g., time, personnel, development capital) in more favorable geographic locations. Ultimately, this would likely result in less attractive projects being submitted and, as a result, higher power costs for ratepayers.

Q. WHAT ARE SOME OF THE IMPLICIT AND EXPLICIT ADVANTAGES THAT UOG PROJECTS RECEIVE IN BID EVALUATION?

A. My testimony focuses on the following advantages that UOG projects receive in bid evaluation:

1. IOUs can amortize the costs of UOG projects over a longer term than PPAs for IPPs. As a result, IOUs may be improperly evaluating the actual total cost of IPP projects and over-stating the costs of IPP projects relative to UOG projects.
2. It appears that IOUs are able to exclude from their bids much of the risk associated with the inherent uncertainty in costs and performance of power plant projects while IPPs must internalize some or all of those uncertainties into their project bids.

The following sections address each of these issues.

A. BID EVALUATION MUST APPROPRIATELY ACCOUNT FOR THE DIFFERENT DURATIONS OF RATEPAYER OBLIGATIONS BETWEEN IPP CONTRACTS AND UOG PROJECTS

Q. ARE PROPOSALS FOR UOG PROJECTS EVALUATED BASED ON CAPITAL RECOVERY OVER A PERIOD SHORTER THAN THE PROJECT LIFE?

A. No. UOG projects are generally evaluated based on capital recovery over the project's book life.[5]

Q. WHY IS THIS?

A. Utilities typically recover the costs associated with UOG projects under cost-of-service ratemaking. Thus, the utility typically amortizes the capital costs of the UOG project over the book life of the asset.

Q. IS IT YOUR EXPERIENCE THAT IPPS TYPICALLY HAVE PPAS WITH TERMS SHORTER THAN THEIR PROJECTS' BOOK LIVES?

A. Yes. In many cases, utilities only allow IPPs to offer PPAs with terms that are shorter than the book life of an IPP asset.[6]

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[5] PSCo response to data request CIEA/ CEC/Thermo 2-7.A1, as presented in Attachment C.

[6] This may not be the case if an existing IPP bids to obtain a new PPA after the termination of its existing agreement.

Q. HOW DOES THIS CREATE A DISADVANTAGE FOR IPPS BIDDING TO SELL VIA PPAS?

A. For financing reasons, IPPs proposing projects selling to PSCo pursuant to PPAs need to incorporate repayment of most or all of the project's debt over the initial PPA term (which is capped by PSCo at no more than 25 years).[7] Bids for utility self-builds would instead be evaluated based on capital recovery over the project's book life, which may be 30 years or more. Since future costs can be discounted significantly in present value calculations used in bid evaluations, the longer capital recovery period for UOG project effectively reduces their bid prices. This puts IPP PPA bids at a disadvantage. This problem is exacerbated in this docket by PSCo's stated preference for short-term PPAs having durations of about 10 years.

Q. COULDN'T THE IPP OBTAIN FINANCING OVER A PERIOD LONGER THAN THAT OF ITS PPA?

A. It might be possible for an IPP to have a very limited portion of its overall financing package extend beyond the PPA period. However, entities financing power projects past the end of the initial PPA would see significant risks associated with this so-called "merchant tail." The perception of greater risk would likely result in an increase in financing costs.

[7] This is particularly true when there are limited opportunities to sell project capacity after the PPA term.

Q. HOW HAS PSCO ATTEMPTED TO EVALUATE PROJECTS WITH DIFFERENT LIVES IN THE PAST?

A. In the 2009 All-Source Solicitation, PSCo evaluated project portfolios using the Strategist capacity expansion planning computer model. The period of analysis extended through 2046. Since IPP contract bid terms would fall well short of 2046, it was necessary to fill in replacement resources (and the costs associated with those replacement resources) from the end of the IPP contract term through 2046. PSCo used generic resource cost estimates to represent the replacement power costs after IPP PPAs terminated, as ordered by the CPUC in the 2007 Colorado resource planning proceeding.[8]

Q. HOW DOES PSCO PROPOSE TO EVALUATE PROJECTS WITH DIFFERENT LIVES IN ITS 2011 ERP?

A. PSCo proposes to continue to use the portfolio evaluation approach based on the Strategist model and to fill in the replacement costs after the PPA term (i.e., "backfilling") with resources from its "least-cost self-build portfolio."[9] The costs of these replacement resources would be based on the proposals submitted by PSCo in the All-Source RFP. If the projects proposed by PSCo do not meet the entire resource need after the end of the IPP bids, then PSCo would backfill with generic resources to perform the evaluation. The replacement resource costs are represented in Strategist using an Economic Carrying Charge approach that converts annual fixed revenue requirements

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[8] PSCo's response to CIEA/CEC/Thermo data request 2-6. A1, page 59, as presented in Attachment D.
[9] PSCo 2011 ERP, Volume II, page 2-329.

(which decline over time as the asset depreciates) into an escalating annual cost that results in the same present value of fixed revenue requirements over the project life.[10]

Note that there is no real guarantee that the generic resources that might be needed for backfilling in the later years of the modeling actually are "least-cost self-build" options. They do not necessarily reflect the actual amounts PSCo would bid to construct a self-build, which may be lower than the costs assumed for generic resources.

Q. WHAT DOES PSCO'S APPROACH TO BACKFILLING IMPLY WITH RESPECT TO FUTURE RESOURCE COSTS?

A. PSCo's backfilling approach implies that the costs following the end of the PPA term would necessarily equal the annualized costs of a new company-owned project that is bid into the RFP or a comparable generic plant in the event that company proposals are insufficient to meet the resource need.

Q. WHAT DOES THIS IMPLY IN PRACTICE?

A. This implies that PSCo must believe that either the UOG resources it uses for backfilling the Strategist model are of equal or lower-cost than potential PPA options from IPPs coming off of their contracts or that the IPP coming off of its PPA would retire the plant and not re-bid its capacity into a new RFP.

[10] PSCo 2011 ERP, Volume II, pages 2-328 through 2-332.

Q. IS THE ANNUALIZED COST OF A NEW COMPANY-OWNED PROJECT AT THE END OF A PPA HIGHER THAN THE PPA PRICE?

A. Depending on the duration of the PPA and the technology, the price of the PPA may be lower than the cost of new entry assumed by PSCo in its backfilling approach.

Q. ARE THERE LIQUID WHOLESALE CAPACITY AND ENERGY MARKETS IN PSCO'S SERVICE TERRITORY INTO WHICH IPPS WITHOUT CONTRACTS CAN SELL THEIR POWER?

A. No. IPP projects located in PSCo's service territory are largely limited to selling to PSCo or attempting to export to other locations at an economic disadvantage given transmission availability and cost.

Q. GIVEN THE OPTIONS AVAILABLE TO IPPS COMING OFF OF EXISTING CONTRACTS, WHAT WOULD YOU EXPECT TO BE THE COST OF REPLACEMENT CONTRACTS WITH THESE PROJECTS?

A. I would expect the cost of power under a replacement contract with these facilities to be no less than the going forward costs of the projects coming off of their PPAs (fixed and variable operating costs, including any needed capital additions). In addition, I would expect that the cost of power under a replacement contract would be no more than the cost of new entry by UOG or new IPP projects at the time the IPP comes off of contract. Since the cost of new generation represents a cap on what IPPs can expect to receive in the market, I would expect the replacement cost to fall somewhere between the going forward costs of existing resources and the cost of new entry. Where the replacement costs fall within that range would depend on the level of competition. Because existing resources coming off of a PPA may not have some of the newest technological attributes of brand new IPP or UOG resources in the future, owners of existing IPPs would need to ensure that their prices were low enough to remain competitive.

Q. WHAT DOES PSCO ANTICIPATE WILL OCCUR IN RESPONSE TO ITS RFP FOR DISPATCHABLE RESOURCES ISSUED PURSUANT TO ITS 2011 ERP?

A. PSCo has specifically designed its 2011 ERP to take advantage of the expected surplus of existing capacity with 1,200 MW of projects coming off contracts and an identified resource need of just 292 MW. According to the testimony of Mr. Haeger, PSCo believes that "...existing generation resources should provide the Company the opportunity to acquire the necessary resources at a price that is lower than developing a new greenfield generation project."[11]

Q. GIVEN PSCO'S EXPECTATION THAT IT WILL BE ABLE TO PROCURE EXISTING RESOURCES AT LESS THAN THE COST OF BUILDING A NEW GENERATION PROJECT, IS IT REASONABLE TO BACKFILL WITH NEW RESOURCES IN ITS STRATEGIST MODELING?

A. No. It is clear that as long as there are existing resources at the end of their contract periods, then those resources would be available to provide replacement capacity at a price below the cost of new generation. By assuming new resources will backfill behind proposed IPP PPAs, PSCo is placing those IPP bids at a disadvantage relative to utility self-build proposals (which have no need for backfilling).

[11] Supplemental Direct Testimony of Kurtis J. Haeger, Docket No. 11A-869E, February 13, 2012, page 4.

Q. WHY ARE IPP BIDS PLACED AT A DISADVANTAGE?

A. By overstating ratepayer costs after the termination of the PPA, PSCo overstates the overall cost to ratepayers associated with a PPA. This places the PPA at a relative disadvantage compared to PSCo's UOG proposals.

Q. DOES PSCO HAVE AN INCENTIVE TO OVER-ESTIMATE THE COSTS OF ITS GENERIC RESOURCES THAT ARE USED FOR BACKFILLING?

A. Yes. PSCo has an incentive under its proposed approach to have the generic resources that it uses for backfilling to be relatively expensive in order to burden the IPP bids with more back-end costs. The higher the generic backfilled resources, the less competitive the IPP bid would be in comparison to a PSCo self-build proposal.

Q. WHAT SHOULD PSCO BE REQUIRED TO DO TO ENSURE THAT PPA AND SELF-BUILD PROPOSALS WITH DIFFERENT LENGTHS ARE COMPARED FAIRLY?

A. Rather than drawing only from its own self-build proposals or generic resources, PSCo should be required to include in its least-cost portfolio estimates of the cost of replacement capacity from existing resources scheduled to reach the end of the term of their PPAs during the evaluation period.

Q. HOW SHOULD PSCO DEVELOP ESTIMATES OF THE COST OF REPLACEMENT CAPACITY FROM EXISTING RESOURCES?

A. PSCo could use the results of bids received in the upcoming procurement cycle following this docket to inform its assumptions about PPA re-bid costs. For example, if an IPP project with an expected life of 30 years is coming off a 10 year PPA and is bidding for a new 10 year PPA, it would be reasonable to expect that the replacement costs for the remaining 10 years of its life after the end of the second PPA term would be comparable to the current re-bid for the second PPA.

The results of the upcoming procurement, which is expected to include re-bids from projects coming off their initial PPAs, may also be used to inform the evaluation of future new-build IPP projects. Rather than backfill with new self-builds or generic resources at the end of an initial PPA for a new IPP project (as proposed by PSCo), PSCo should use an estimate of the cost of procuring from that project under a second re-bid contract. The cost of the re-bid contract can be estimated based on the results of the upcoming procurement by comparing re-bid prices to the original PPA prices. That ratio can be applied to a new PPA bid to estimate the cost of backfilling by re-contracting with that resource at the end of its term. To the extent that PPAs have previously been re-negotiated and extended to a longer term (so called "blend and extend" recontracting), the price for the "blend and extend" contract may be compared to the original PPA price to determine the relationship between prices for the original term and the term that has been added to the agreement.

Only after all of the existing uncontracted capacity has reached the end of their useful life would it be reasonable to use the cost of new generation for backfilling at the end of a contract term during bid evaluation.

B. The bid evaluation process must address the differential risk between UOG and IPP projects

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section of testimony will address the need to properly consider the ratepayer risks associated with UOG and IPP projects in evaluating project bids. As will be demonstrated, UOG projects tend to pose higher ratepayer risk than both new IPP projects and recontracting existing IPP facilities. If this risk is not reduced to be more comparable to the risk from IPP projects and if the cost of this risk is not reflected in bid evaluations, PSCo could potentially select a UOG project whose total cost to ratepayers (i.e., incorporating the cost of risk) is higher than competing bids from IPPs.

It is critical to note that risk is only one factor, along with price, term, flexibility, transmission, load support and other elements that affect the assessment of different elements. However, it is an essential factor to capture in the evaluation of competing proposals (and would be ignored under PSCo's proposed bid evaluation proposal).[12]

1. Risk Differential Between IPP and UOG Projects

Q. ARE THERE DIFFERENCES IN THE AMOUNT OF RATEPAYER RISK ASSOCIATED WITH PSCO'S UOG PROJECTS AND IPP PROJECTS?

A. Yes. Since PSCo recovers costs associated with its UOG projects on a cost-of-service basis, ratepayers are at risk for any differences between PSCo's projected costs assumed in bid evaluation and its costs that are actually incurred (and recovered through rates).

[12] Supplemental Direct Testimony of Kurtis J. Haeger, Docket No. 11A-869E, February 13, 2012, page 5.

PPAs typically are not cost-of-service agreements. As a result, IPPs absorb the risk of many cost over-runs. For example, if PSCo priced a UOG bid based on an expected heat rate of 7,000 Btu/kWh, but the plant ended up having a heat rate of 7,500 Btu/kWh because of unforeseen but reasonable circumstances, ratepayers would generally be required to pay for the UOG's reasonably-incurred fuel costs that are higher than expected during bid evaluation. On the other hand, where the project selling to PSCo under a PPA has a guaranteed heat rate of 7,000 Btu/kWh and the IPP's actual heat rate was 7,500 Btu/kWh, the IPP would generally need to compensate PSCo's ratepayers for its failure to meet its guaranteed heat rate. For this and other reasons, the ratepayer risk for a project selling pursuant to a PPA is less than that typically seen in UOG projects.

Q. WHAT ARE UNCERTAIN FACTORS IN UOG PROJECTS FOR WHICH RATEPAYERS MAY BE AT RISK?

A. Uncertain factors in UOG projects for which ratepayers may be at risk include the following:

1. Cost of operations (initially and over time);
2. Fuel prices;
3. Plant performance (initially and over time);
4. Plant availability on critical days;
5. Cost of future capital additions;
6. Potential changes to rate of return over time;
7. Risk of technological obsolescence;
8. Cost of construction;
9. Project completion risk; and

10. Potential impacts on cost of capital.

Q. ARE THERE UNCERTAIN FACTORS IN IPP PROJECTS FOR WHICH RATEPAYERS ARE AT RISK?

A. Yes, there can be a number of such factors. As discussed below, many can be mitigated by contract structure and terms or by other requirements. The factors I have identified, including all the factors identified in Mr. Haeger's testimony,[13] are as follows:

1. New project completion risk (mitigated by collateral requirements and liquidated damages clauses);
2. Fuel prices (depending on contract);
3. Other indexed prices (depending on contract);
4. Potential for price renegotiation (subject to utility and Commission approval);
5. The potential for non-operations on critical days at a cost in excess of performance guarantees (mitigated by PSCo's proposed contract);
6. Cost for replacement power at the end of the PPA; and
7. Debt-equivalence or other accounting risks.

Q. HOW DO THE RISKS OF UOG PROJECTS AND IPP PROJECTS COMPARE?

A. Table 1 below examines each of the identified categories of risk and their applicability to UOG and IPP projects. This table (along with the subsequent explanatory text) demonstrates that UOG projects impose greater ratepayer risk than IPP projects.

[13] Supplemental Direct Testimony of Kurtis J. Haeger, Docket No. 11A-869E, February 13, 2012, page 6.

This difference arises because ratepayers are at risk for all reasonably incurred plant costs and for the lifetime performance of UOG projects, whereas ratepayers are at risk for a smaller subset of elements for PPAs. Of those elements for which ratepayers do bear risk in PPAs, ratepayers face nearly the same risks with regard to UOG projects however, with UOG projects, ratepayers often have less ability to mitigate the impact of these risks. Most of the risks associated with UOG projects are typically borne solely by the ratepayer, whereas for IPP projects, the IPPs are generally required to absorb cost overruns and to compensate ratepayers for performance shortfalls.

Table 1: Comparison of Ratepayer Risks from IPP and UOG Projects

	Ratepayer Risk for Existing IPP Project Recontracting?	Ratepayer Risk for New IPP Projects?	Ratepayer Risk for UOG Projects?
Fuel prices	Usually, but depends on contract	Same as existing IPP	Yes
Cost of operations	Maybe, but depends on contract: ratepayers may bear some (symmetrical) risk from indexed pricing	Same as existing IPP	Yes
Plant performance	No[14]	Same as existing IPP	Yes
Potential for non-operations on critical days	Depends on contract (No, under PSCo's Model PPA)[15]	Same as existing IPP	Yes
Unanticipated capital additions	No	Same as existing IPP	Yes
Risk associated with term of commitment	Yes: risk from uncertainty in cost for replacement power at PPA end, but risk is mitigated by discounting until the end of the contract period and is symmetric.	Same as existing IPP	Yes: risk of technological obsolescence and large increases in cost of fuel over the plant lifetime
Accounting risk	Maybe: ratings agencies (Moody's and Standard and Poor's) already adjust the utility's financial statements to include an estimate of debt for PPAs. Any change from their current methodology resulting from changes in accounting standards could potentially impact the utility's cost of capital.	Same as existing IPP	Maybe: potential impacts on cost of capital
Cost of construction/ potential for PPA price renegotiation	No	Yes, but substantially mitigated by requirement for utility agreement and Commission approval	Yes, with lower "reasonableness" bar for Commission approval
Project completion risk	No	Yes, but substantially mitigated by collateral requirements and liquidated damages clauses	Yes
Rate of return over time	No	No	Yes

[14] PSCo Model Dispatchable PPA, provided as Attachment 3.1-3 to Volume III of PSCo 2011 ERP, Article 12, page 30.
[15] PSCo Model Dispatchable PPA, page N-1.

Q. HOW ARE FUEL PRICE RISK, INDEXED PRICE RISK, AND PROJECT COMPLETION RISK FOR IPP PROJECTS MITIGATED BY CONTRACT LANGUAGE AND STRUCTURE?

A. PPAs typically address project completion risk (including the risk of project delay) by requiring security guarantees from the IPP sufficient to fully compensate the offtaker if the project is not constructed. This security should be adequate to compensate ratepayers for costs related to replacement power and other damages. For example, PSCo's Model PPA requires sellers to pay liquidated delay damages of $300 per MW per day for a delay in commercial operations for up to 120 days past the agreed-upon commercial operation date.[16] Further delay is considered an Event of Default, which would allow PSCo to terminate the PPA.[17] The Model PPA additionally requires IPPs to maintain (until the start of commercial operations) a security fund of $175 per kW from which such damage payments can be made.[18] Mr. Haeger's testimony correctly notes that PSCo "has included security deposits and other conditions in PPAs to help manage [performance and operational] risks."[19] There is no completion risk associated with the recontracting of an existing facility.

Fuel price risk can be assigned either to PSCo or to the IPP, depending on the structure of the agreement. Fuel price risk can also be shared by indexing the PPA price to a market price of fuel. This type of risk and the risk of other indexed pricing should lower the value of the PPA relative to equivalent PPAs that are not indexed. Indexed pricing should

[16] PSCo Model Dispatchable PPA, page A-8.
[17] PSCo Model Dispatchable PPA, Section 12.1 (G), page 29, and Definitions, page A-5.
[18] PSCo Model Dispatchable PPA, page A-11.
[19] Supplemental Direct Testimony of Kurtis Haeger in Docket No. 11A-869E. February 13, 2012, page 6.

therefore only be agreed to in return for a lower-cost PPA. Alternately, PSCo could require the IPP to fully bear the risk of fuel, inflation, and other cost inputs by setting the PPA at a fixed per-kWh amount regardless of changes to cost inputs.

Q. ARE ANY OF THESE RISKS TYPICALLY MITIGATED FOR UOG PROJECTS?

A. No. If a UOG project is delayed or not completed, ratepayers would typically fully bear the cost of procuring replacement power unless the Commission disallows costs because of gross mismanagement of the project's development or construction process. Ratepayers would also bear the reasonably incurred cost of higher-cost power resulting from such items as fuel cost increases during plant construction or throughout plant operations. Ratepayers would be required to pay for replacement generation for the period in which the plant is non-operational, bear the cost of extra fuel and environmental compliance if the plant's heat rate degrades more than expected, and pay the full rate of return and plant depreciation regardless of the level of the plant's availability (assuming all of these charges are deemed reasonable by the Commission).

Q. WHY AREN'T RATEPAYERS AT RISK FOR PLANT PERFORMANCE FOR IPP PROJECTS?

A. PSCo's Model PPAs include performance requirements. If an IPP project does not meet these requirements, the IPP must provide damage payments to PSCo to cover the cost to ratepayers of the performance shortfall.[20] Ratepayers are therefore not at risk for plant performance shortfalls.

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[20] PSCo Model Dispatchable PPA, Article 12, page 30.

Q. AREN'T RATEPAYERS AT RISK FOR POTENTIAL NON-OPERATIONS ON CRITICAL DAYS?

A. Not under PSCo's Model Dispatchable PPA. While PSCo states that under its Model Dispatchable PPA, "the failure to perform on a critical day is not differentiated from failing to perform on any other day,"[21] this is not consistent with the Model Dispatchable PPA provided as an attachment to PSCo's ERP. This Model PPA includes a provision for penalties for non-operations during Escalated System Condition (ESC), which may be called "based upon a shortage of power, a shortage of operating reserves and/or any other reason [for an elevated concern regarding system reliability]."[22] Penalties can be as high as $0.25 per kWh during ESC events.[23] As long as they are set appropriately, such penalties would fully compensate ratepayers for the cost of replacement power were an IPP project not fully operational during as ESC event.

Q. WOULD RATEPAYERS BE AT RISK FOR HEAT RATE DEGRADATION UNDER A TOLLING AGREEMENT WITH AN IPP?

A. For the most part, no. PSCo's model PPA includes a provision for a heat rate adjustment to payments. If the actual plant heat rate exceeds the predicted heat rate by more than 2% over the course of a month, PSCo reduces payments to the IPP to offset PSCo's increased cost of fuel.[24] Ratepayers are therefore at risk for only up to 2% degradation.

[21] PSCo response to CIEA/CEC/Thermo data request 2-9d as presented in Attachment E.
[22] PSCo Model Dispatchable PPA, page A-4
[23] PSCo Model Dispatchable PPA, page N-1
[24] PSCo Model Dispatchable PPA, Article 8.4, page 19.

Furthermore, if an IPP project's heat rate is superior to (i.e., less than) the predicted heat rate by more than 2% over the course of a month, PSCo increases payments to the IPP to compensate for PSCo's reduced cost of fuel, but this payment covers only half of PSCo's avoided fuel costs.[25] In other words, the IPP takes all of the downside risk for heat rate degradation above 2%, while any upside risk for heat rate improvements of more than 2% is shared equally with ratepayers.

Q. WHY IS THERE A RISK DIFFERENTIAL BETWEEN UOG AND IPP PROJECTS WITH REGARD TO CAPITAL ADDITIONS?

A. If capital additions were required over the life of a UOG project, ratepayers would typically be required to bear the full cost of the additions, regardless of whether these costs were anticipated at the time that the project received regulatory approval. For an IPP project, typically the IPP itself would bear these costs.

Q. PLEASE EXPLAIN THE RISKS ASSOCIATED WITH THE TERM OF COMMITMENT.

A. PPAs tend to be of shorter duration than the plant lifetimes over which UOG projects are evaluated and committed to ratepayers. This difference in tenure creates a different type of risk for each of the agreements: for the shorter PPAs, the risk is that PSCo may have undervalued replacement power costs at the end of the contract period when evaluating the PPA; for the longer UOG projects, the risk is that the project may become technologically obsolete over the course of the plant lifetime or economically less useful due to changes in fuel or other operating costs.

[25] PSCo Model Dispatchable PPA, Article 8.4, page 20.

With regard to the forecast risk associated with PPAs, it is important to note that PSCo may either underestimate or overestimate future market costs for the period subsequent to the end of the PPA. The higher the forecast, the less valuable IPP projects will appear relative to UOG projects. PSCo therefore appears to have an incentive to be conservatively high in estimating future replacement power costs, which would imply that the actual risk to ratepayers associated with underestimating replacement power costs is not large. As discussed earlier in this testimony, given the incentives in place, the greater risk may be that PSCo selects a higher-cost UOG project in place of a lower-cost IPP project justified in part by an *overestimate* of power costs after the end of a PPA.

The risk of technological obsolescence (resulting in UOG projects that become uneconomic) can be substantial over a plant lifetime. For example, fuel costs typically are the majority of the lifecycle cost of a fossil-fired generation project. Making a 40- to 45-year bet on the relative price of the fuels, in the face of large fuel price uncertainty, locks ratepayers into potentially very expensive costs if the relative prices of gas, coal or other fuels shift in a dramatic way (as has occurred historically). A shorter-term PPA reduces this risk.

As another example, newer gas turbines that can provide quick start capabilities, fast ramping, and higher efficiencies offer improvements over what was available just five years ago,[26] particularly for integrating variable renewable resources. Utilities saddled

[26] For example, General Electric announced a new generation technology in September 2011, the FlexAero LM6000-PH, which can ramp up at a rate of 50 MW per minute and reach efficiency rates above 80 percent without requiring any water. General Electric Press Release. "GE Launches Advanced Energy Technology for

with older technologies face less operational flexibility and higher heat rates and cooling water requirements, all of which would result in higher costs to ratepayers. A utility in this position would likely continue to operate its aging UOG project at a cost to ratepayers that would be higher than what the cost would be for newer technologies that are now available. In this case, ratepayers would continue to pay a rate of return until the plant is fully depreciated, regardless of how much power the plant was actually providing to consumers. Alternatively, had the utility procured power under a shorter-term PPA, the utility could procure power from a new power project with more-advanced technology and effectively replace the obsolete plant with one that has lower-cost or that better meets system needs. In other words, PPAs allow the utility to make shorter-term bets with ratepayers' money and to defer long-term decisions during periods of uncertainty.

Q. HOW DO THE ACCOUNTING RISKS OF IPP AND UOG PROJECTS COMPARE?

A. The need of PSCo for a significant amount of up-front capital to finance a UOG project could create credit risk and increase PSCo's cost to finance ongoing operations or other capital projects. PSCo could face potential impacts on its cost of capital if PPAs are consolidated on its balance sheet due to potential future change in lease accounting standards; however, as discussed below, this risk is uncertain since future changes in accounting standards may or may not materialize.

Fast, Flexibly Use of Abundant Natural Gas with No Need for Water." September 14, 2011, as presented in Attachment F.

Q. WHY DO YOU BELIEVE THE BARRIER FOR RATEPAYER PASS-THROUGH OF CONSTRUCTION COST INCREASES TO BE HIGHER FOR IPP PROJECTS THAN FOR UOG PROJECTS?

A. If an IPP approaches PSCo seeking a higher PPA price, PSCo is under no obligation to agree. If an IPP proposes such a change prior to signing the PPA, PSCo would be highly unlikely to agree to the higher price unless that bid remained cost-effective even with the increase. Indeed, PSCo reports that it denied a price increase proposed by one of the IPPs short-listed in its 2008 Wind Resource RFP and also denied a price increase proposed by one of the IPPs short-listed in its 2009 All-Source Solicitation.[27] Both requested increases resulted in termination of the PPA negotiations.

If an IPP attempts to obtain an increase in contract price after the PPA has been signed, PSCo would generally have the upper hand in the negotiations because the collateral requirements, liquidated damages clauses, and performance guarantees that are typically part of PPAs would require the IPP to compensate PSCo if it failed to perform under the contract. PSCo would generally not have an incentive to accept a higher price without some benefit offered by the IPP as long as refusing to accept the IPP's offer would result in a better deal for ratepayers (either by maintaining existing contract terms or by triggering damage payments by the IPP).

Under either circumstance, the Commission would be required to approve a higher contract price once PSCo's agreement had been attained. This regulatory approval would

[27] PSCo response to data request CIEA/CEC/Thermo2-9c i, as presented in Attachment E.

generally be provided only if the Commission determined that the revised contract was in ratepayers' best interest.

UOG construction cost increases, on the other hand, are evaluated by the Commission based on the "reasonableness" yardstick, which in general terms means that cost increases are allowed to be passed through to ratepayers as long as no gross mismanagement is evident.[28] This is a much lower bar than the "in the best interest of ratepayers" yardstick that would be used to evaluate a requested PPA price increase. For example, cost overruns due to increases in the costs of labor or construction materials would generally be deemed reasonable and passed through to ratepayers for UOG projects, whereas an IPP would generally not be able to receive a higher PPA price on account of such cost overruns unless the IPP could make an extremely compelling case both to PSCo and to the Commission that it would be in the best interest of ratepayers to proceed with the PPA even at the higher cost.

Q. WHAT IS THIS RATE-OF-RETURN RISK FROM UOG PROJECTS?

A. If PSCo's financing costs increase or there are other increases to PSCo's rate of return over the plant lifetime, this would increase ratepayers' cost for the project. Ratepayers would be required to bear this increase. There is no equivalent risk for IPP projects.

[28] *See e.g.,* C.R.S. § 40-3-101(1).

Q. WOULD IT BE CORRECT TO SUMMARIZE THIS DISCUSSION OF RISKS BY STATING THAT UOG PROJECTS GENERALLY CREATE GREATER RATEPAYER RISK THAN IPP PROJECTS?

A. Yes. While IPP projects do pose some risk to ratepayers, most of these risks are or can be mitigated by damage clauses and other provisions in the PPA. UOG projects share all the risks posed by IPP projects (sometimes in a somewhat different form), but ratepayers are generally more exposed to these risks when they come from UOG projects. In addition, UOG projects pose a number of risks to ratepayers that are generally not posed by IPP projects (e.g., capital additions, plant performance, rate of return).

Q. DON'T RATEPAYERS HAVE BOTH UPSIDE AND DOWNSIDE RISKS FROM UOG PROJECTS?

A. In theory, yes. However, in practice, the downside risk is greater given the incentive in place: if PSCo biases its UOG bid in favor of lower cost and higher performance expectations, it is more likely to have its bid accepted, and it faces little risk from this strategy, since any subsequent cost increases are nearly guaranteed ratepayer recovery as long as they pass the low bar for reasonableness.

Q. ARE THERE ARE ALSO RISK DIFFERENTIALS BETWEEN DIFFERENT IPP PROJECTS?

A. There can be. The amount of ratepayer risk from an IPP project can depend on whether the project is new or existing, whether or not it has a firm fuel supply, the terms of its PPA, the technologies that it uses, its location on the grid, the developers' experience, and other parameters. That said, the risk posed by UOG projects is nearly always greater than the risks posed by IPP projects because IPPs assume a share of the IPP project risks, whereas UOG project risks are generally borne entirely (or almost entirely) by ratepayers.

2. Approaches to Addressing the IPP-UOG Risk Differential

Q. IS THE RISK DIFFERENTIAL BETWEEN UOG AND IPP PROJECTS IMPORTANT TO CUSTOMERS?

A. Yes, according to PSCo, "customers want to strike a balance with the level of certainty and the level of cost. Customers oppose certainty at any cost and oppose complete uncertainty even if the price is lower."[29] In other words, customers are sensitive to risk and would prefer to pay somewhat higher prices in exchange for greater price stability. Risk should therefore be considered as part of bid selection, along with price, timing, and other factors.

Q. HOW DOES PSCO PROPOSE TO ADDRESS THIS RISK DIFFERENTIAL?

A. PSCo is not proposing to apply any risk adjustments to UOG or IPP proposals.[30]

Q. IS THIS REASONABLE?

A. No, given the importance of the risk differential to customers and the ready availability of solutions to significantly mitigate the differential or to incorporate it into the bid evaluation process, it is unreasonable not to consider it. Ignoring the risk differential ignores real ratepayer costs from UOG projects and could result in the selection of projects that are costlier to ratepayers than competing bids.

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[29] PSCo response to CIEA/CEC/Thermo data request 2-10c, as presented in Attachment E.
[30] Supplemental Direct Testimony of Kurtis Haeger in Docket No. 11A-869E. February 13, 2012, page 5.

Q. IN WHAT WAYS COULD THIS RISK DIFFERENTIAL BE ADDRESSED SO AS TO PROVIDE A MORE LEVEL PLAYING FIELD BETWEEN IPP AND UOG BIDS?

A. There are a number of ways to address this risk differential. For example:

1. The Commission could make UOG projects ineligible to compete in competitive solicitations against IPP bids in this docket;
2. The Commission could set cost recovery for UOG projects for the first ten years of operations based on the assumptions presented in the UOG bids; and/or
3. The Commission could require bid evaluators to assign bid adders to UOG projects that impose higher ratepayer risk to account for this incremental risk.

Q. HOW WOULD EXCLUDING UOG PROJECTS ADDRESS THIS RISK DIFFERENTIAL?

A. The easiest way to address the risk differential is to not allow UOG projects to compete in PSCo RFPs in this ERP. In this scenario, all RFP bids would be from IPPs for projects that would pose similar risks to ratepayers. This would allow projects to be considered according to price, performance, and location criteria without the need to evaluate significant risk differential and their impacts.

Q. DO OTHER JURISDICTIONS USE THIS APPROACH?

A. The California Public Utilities Commission recently adopted this approach, ruling, "it is inappropriate to have UOG projects participate in utility generation [Requests for Offers

(RFOs)]."[31] This decision was in agreement with several parties in the case that cited difficulties in comparing UOG and IPP bids, including one of the major California investor-owned utilities, Southern California Edison, which "believes that proposed UOG projects should not be considered in an IOU's competitive bid solicitation because they are fundamentally different from PPAs."[32] In explaining its decision, the California Commission acknowledged the need to address the disparity between UOG and IPP bids and also cited concern over potential market impacts from including UOG projects in utility RFPs:

> Even if theoretically it might [be] possible to have a utility-owned project compete fairly in a utility-run RFO, in practice it will never look fair. In particular, any time that a utility-owned project is selected in such an RFO, it will give an appearance of favoritism. Regardless of how fair an RFO was, if it looks like the one competitor had an inside track or that the judging was [biased], some of the benefits of using an RFO are largely eviscerated. Potential participants may try to avoid that market, which is not a desirable outcome in the context of electricity procurement.[33]

If a competitive solicitation fails to provide a utility with the power that it sought, the California Commission will allow the utility to seek approval for a UOG project using the certificate of public convenience and necessity (CPCN) process. However, before the California Commission would authorize an IOU to propose such a project, the California Commission must determine that the solicitation was fair and that it did, in fact, fail.[34]

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[31] California Public Utilities Commission decision D.12-04-046 in Rulemaking R. 10-05-006, April 19, 2012, page 31, as presented in Attachment G.
[32] Southern California Edison opening brief in R. 10-05-006, page 22, as cited in California Public Utilities Commission decision D.12-04-046, page 29, as presented in Attachment G.
[33] California Public Utilities Commission decision D.12-04-046, page 31, as presented in Attachment G.
[34] California Public Utilities Commission decision D.12-04-046, page 38 and Ordering Paragraph 6, page 74, as presented in Attachment G.

Q. DO YOU RECOMMEND THAT THIS PROCESS BE USED FOR PSCO?

A. Yes, I recommend that the Commission adopt this process for PSCo, particularly for the current ERP. If the Commission determines that PSCo requires incremental power, PSCo should be required to hold a competitive solicitation for this power and should not be allowed to bid in this solicitation. If this solicitation fails, PSCo should be allowed to submit a stand-alone application to the Commission seeking approval for a UOG project that would meet the solicitation criteria. It would be important for the Commission to approve this project only if PSCo could establish that the failed solicitation was fair and was not designed to fail and only if the proposed project seemed reasonable compared with recent bids for comparable IPP projects.

Q. ARE THERE CIRCUMSTANCES THAT WEIGH IN FAVOR OF THIS APPROACH AT THIS TIME IN COLORADO?

A. Yes. First, since the last resource planning process, PSCo's market share of its generation portfolio has greatly increased (from 47%[35] to 68%[36]). Second, this resource plan contemplates only a modest amount of new resource need (292 MW through 2018).[37] Third, several IPP projects are coming off of existing PPAs, making it almost certain that IPP bids will be numerous enough and sufficiently low-cost to fill the limited resource needs in this resource plan. If PSCo were ineligible to bid, it would start to restore Colorado's competitive balance between IPPs and PSCo. Given the termination of a number of PPAs prior to 2018, even if all of the resource need identified in this docket

[35] Testimony of David A. Svanda on Behalf of CIEA in Docket No. 07A-447E, April 2008, page 9, as presented in Attachment B.
[36] PSCo 2011 ERP, Volume 2, page 57.
[37] PSCo 2011 ERP, Volume 1, Table 1.4-2 on page 1-27.

were filled by IPPs, PSCo's market share of the generation portfolio in 2018 would be 73%.[38] Adding the possible replacement of Cherokee 4 and Arapahoe 4 with more flexible IPP resources would leave PSCO's market share at 67%.[39]

Q. HOW ELSE COULD THE COMMISSION ADDRESS THE RISK DIFFERENTIAL BETWEEN UOG AND IPP PROJECTS?

A. The Commission could significantly mitigate this risk differential by setting ratepayer recovery for UOG projects for the first ten years of operations based on the assumptions used in evaluating the UOG bids instead of actual plant cost and performance. Requiring PSCo to adhere to the cost and performance projections used in its bid would put UOG and IPP projects on much more equal footing, rather than allowing PSCo to use one set of values in its bid, a different set of values in its CPCN and, if actual costs exceed the CPCN amount, obtain cost recovery of an even higher amount (as is currently the case). As noted below, PSCo's costs rose in such a way in the bidding, approval, and construction of the Comanche 3 plant.

Q. WHAT SUPPORT IS THERE FOR THIS APPROACH?

A. This approach was recommend by Dr. Tierney and Dr. Schatzki of The Analysis Group in a 2008 paper for the National Association of Regulatory Utility Commissioners (NARUC). Dr. Tierney and Dr. Schatzki identify, as a key safeguard against improper self-dealing, the requirement of "comparable forms of risk mitigation in utility and non-utility offers, such as comparable treatment of offer 'refreshing' and hedging of various types of risks, including development and construction risk, power plant performance

[38] PSCo 2011 ERP, Volume 2, pages. 56-57.
[39] PSCo 2011 ERP, Volume 1, page 1-6 and Volume 2, pp. 56-57.

risk, fuel price risk, and risks tied to changes in law or regulation, such as costs of mitigating carbon emissions."[40] In other words, insofar as IPPs are not able to refresh their offers following Commission approval of their projects, a utility should also not be able to change its cost and performance assumptions following Commission approval.

More recently, the California Public Utilities Commission adopted this approach for UOG projects that are developed as a result of a failed solicitation.[41] In doing so, they cited to the brief of a consumer advocacy group, The Utility Reform Network (TURN):

> The Commission should require that the critical cost parameters of any UOG bid should be binding on the IOU for the first ten years of project operations. "Critical cost parameters" include initial capital costs, capital additions, fixed and variable O&M, and heat rates. TURN witness Woodruff explains that this requirement is appropriate because of "the potential for the costs of UOG resources to escalate from those upon which the evaluation and selection was based." Given the typical treatment for UOG resources, in which IOUs are not held to forecasts of cost or performance after the project achieves initial commercial operation, the Commission must take action to create real accountability so the original selection process is not unfairly biased in favor of UOG.
>
> Absent this type of accountability, IOUs have an incentive to assume superior long term cost and performance advantages of UOG projects. Since the Commission rarely, if ever, revisits these initial assumptions, there is no penalty to making overly optimistic projections that are never realized. Even if they are revisited, the IOU need only demonstrate that the costs are reasonable at the time they are incurred. The absence of any accountability mechanism only emboldens IOUs to game this process to the benefit of shareholders and the detriment of ratepayers.[42]

[40] Susan Tierney and Todd Schatzki. "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices." The Analysis Group. July 2008, p. viii, as presented in Attachment H.
[41] California Public Utilities Commission decision D.12-04-046, pages 34-36, as presented in Attachment G.
[42] TURN opening brief in R.10-05-006, page 7-8, cited in California Public Utilities Commission decision D.12-04-046, page 34, as presented in Attachment G.

The California Commission determined that in the case of a failed solicitation that allows UOG projects to be bid, requiring the IOUs to adhere to their bids "is a reasonable approach to equalize the playing field between UOG and PPA."[43]

Q. DO YOU RECOMMEND THIS APPROACH FOR PSCO?

A. If PSCo is allowed to bid in its RFPs, I recommend that the Commission set cost recovery for PSCo's UOG projects based on the cost and performance assumptions used in the project bid that received Commission approval. This would protect customers from unexpected cost increases, such as the increases faced by ratepayers when the Comanche 3 coal plant was built over budget.[44] It would also eliminate the utility's incentive to underestimate project costs or over-estimate project performance in order to win its own solicitation.

This approach should be used both for UOG plants that are selected in a competitive solicitation (if my recommendation to make UOG bids ineligible for PSCO's solicitations is not adopted) and also for plants approved through stand-alone CPCN applications to the Commission.

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[43] California Public Utilities Commission decision D.12-04-046, page 36, as presented in Attachment G.
[44] Supplemental Direct Testimony of Gregory L. Ford in Docket No. 11A-869E. February 13, 2012, page 2.

Q. WOULD SETTING RATE RECOVERY BASED ON COST AND PERFORMANCE EXPECTATIONS IN THE WINNING BID POSE AN UNDUE RISK FOR PSCO SHAREHOLDERS?

A. No, PSCo would have two options to address this risk: PSCo's shareholders could bear the risk, or PSCo could procure third-party contracts and other hedges to transfer the risk to other parties. The costs of these contracts and hedges could be borne by shareholders, or they could be included in the UOG bid price. PSCo would therefore have the option to entirely shield shareholders from the risk of cost overruns if it wished.

Q. IS YOUR COST RECOVERY APPROACH CONSISTENT WITH PSCO'S PROPOSAL IN ITS ERP?

A. No. On the contrary, PSCo has asked for a 20% cushion on its construction and O&M cost estimates.[45] Furthermore, PSCo states that actual costs will fall within this cushion but does not propose to absorb cost increases beyond this cushion if cost increases turn out to be higher.

Q. IS THIS 20% COST CUSHION REASONABLE?

A. No. IPPs are held to a single price point. As the Commission determined in PSCo's 2008 ERP proceeding, PSCo should be held to this same standard:[46]

> Although Public Service typically provides facility cost proposals in the form of a cost plus or minus a certain percentage variance, we direct the Company to establish a point cost in its proposal. This may be a cost without any percentage variance. Alternatively, Public Service can include any such contingency as a part of its proposed cost, but the point cost used in bid comparison will include the full variance amount, and we will not consider a range. We expect this point

[45] PSCo 2011 ERP, Volume 1, page 1-46.
[46] Decision No. C08-0929 in Docket No. 07A-447E. Paragraph 189 on page 61, as presented in Attachment I.

> cost cap level to be the maximum amount that is used in future cost recovery proceedings, absent a showing of extraordinary circumstances.

Consistent with this ruling, if PSCo submits a bid with a 20% cushion, bid evaluation should be done based on the upper end of the cost range, and ratepayer cost recovery should be limited to this amount. If PSCo fails to meet this price point, ratepayers should not be harmed. Barring this, PSCo has an incentive to underestimate its costs in order to have its bids selected, which then puts ratepayers at risk for uneconomic costs.

Q. WOULD LIMITING RATE RECOVERY TO PSCO'S BID (INCLUDING ANY CUSHION AMOUNT) BE EQUIVALENT TO YOUR PROPOSAL?

A. No. Limiting rate recovery to PSCo's bid would remove the risk differential associated with construction costs, but it would not address the risk differential associated with performance and costs during the first ten years of operations. Ratepayers would continue to be burdened with the costs of unexpected capital additions, lower-than-expected heat rates, higher-than-anticipated O&M costs, and other changes to operating costs. To place UOG and IPP bids on equal footing, total cost recovery for the project (including both construction costs and operating costs) should be limited to the costs and performance characteristics used in the project bid for the first ten years.

Q. IS THIS RATE-RECOVERY APPROACH CONSISTENT WITH THE COMMISSION'S DECISION IN PSCO'S 2008 ERP PROCEEDING?

A. In the last ERP, the Commission determined that steps must be taken to level the playing field between IPP and UOG bids:[47]

[47] Decision No. C08-0929 in Docket No. 07A-447E. Paragraph 187 on page 60, as presented in Attachment I.

> With a rate-based proposal the utility has a reduced incentive to make sure the estimate will cover its costs, and it has a weaker incentive to make sure the project stays within budget. [Footnote 12: As discussed above, we disagree with Public Service's argument that budgeting and internal review provides a meaningful limit on costs.] The IPP has a large incentive in both cases. We agree with CIEA and CEC that we must take steps to place the utility proposal on equal footing with fixed price IPP bids.

Accordingly, the Commission required PSCo to include a cost cap in any of its bids, with expenditures above this cap to be borne by shareholders.[48] The Commission adopted this approach in place of requiring PSCo to submit UOG bids as binding fixed-price bids.[49]

My proposal extends the cost cap approved in the last decision to include not just construction costs, but all plant costs throughout the first ten years of plant operations. However, it stops short of requiring PSCo to submit proposals as fixed-price bids. Instead, my proposal requires PSCo to bear risk for project costs only through the first ten years of operations, thereby allowing PSCo to use cost-of-service ratemaking for its UOG projects for the bulk of the plant's lifetimes. It is therefore in line with the decision in PSCo's 2008 ERP and can be seen as an extension of this decision that would further improve the competitive fairness of PSCo RFPs.

[48] Decision No. C08-0929 in Docket No. 07A-447E. Paragraph 188 on pp 60-61, as presented in Attachment I.
[49] Decision No. C08-0929 in Docket No. 07A-447E. Paragraph 185 on page 59, as presented in Attachment I.

Q. IF THE COMMISSION DOES NOT ADOPT ONE OR BOTH OF YOUR RECOMMENDED APPROACHES TO ADDRESS THE UOG-IPP RISK DIFFERENTIAL, HOW COULD THE COMMISSION INCORPORATE THIS RISK DIFFERENTIAL INTO THE BID EVALUATION?

A. The Commission could develop quantitative measures of the incremental risk from UOG projects that would be applied as bid adders to UOG project bids.

Q. HOW WOULD THESE BID ADDERS BE DEVELOPED AND IMPLEMENTED?

A. The risks to ratepayers from all bids would be explicitly considered by evaluating the potential risk of each bid element. For example, if the O&M price embedded in an IPP bid were a fixed price with a pre-specified escalation rate, it would have no ratepayer risk (i.e., uncertainty) associated with it, since the IPP would absorb any variation in costs relative to the bid. However, if increases in O&M costs relative to the costs used in evaluating a project proposal would be passed through to ratepayers, as is often the case with UOG projects, then the bid evaluation process must consider the potential for O&M cost increases. As described in more detail below, whenever this is the case, the utility and the independent evaluator would add to the O&M cost for the UOG bid an adder to reflect the risk to ratepayers of such a cost increase.[50] This adder is needed to more

[50] If an IOU enters into a long-term service agreement or other type of hedging agreement that assigns a project's cost overruns to a third party, the UOG project would not be assigned the adder associated with the risk covered by that agreement. However, the Commission should require the IOU to file annual compliance reports to ensure that this agreement (or an equivalent agreement) remains in place throughout the life of the project.

accurately assess the true expected costs to ratepayers of projects for which they bear the risk of cost increases.[51]

Q. IS THERE A THEORETICAL BASIS FOR CONSIDERING RISK AS PART OF A BID PRICE?

A. Yes. Consider, for example, the following publications:

- In a 2008 *Electricity Journal* article comparing tolling agreements to renewable energy contracts, Dr. C.K. Woo concluded that a contract's value-at-risk should be incorporated into the decision-making process to account for the different risk profiles of these two types of agreements.[52]

- In the 2008 NARUC paper by The Analysis Group cited above, Dr. Tierney and Dr. Schatzki identified key criteria for evaluating offers. These include "[shifts] in risks among the utility, the seller and retail customers associated with various provisions in the contract, such as fuel price indices, availability penalties, collateral requirements of the utility and supplier, [and other] non-price policy factors and considerations."[53] Furthermore, they note that a "successful evaluation should attempt to account for these costs and risks, assign weights that appropriately reflect the value proposition (and risks) to customers, make comparable evaluations across all offers (including self-build and

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[51] See, for example, C. K. Woo. "Cross hedging and forward-contract pricing of electricity?" *Energy Economics* 23 (2001) p. 1 ("[The energy price] is the sum of a baseline price and a risk premium."), as presented in Attachment J.
[52] C. K. Woo. "Should a Lower Discount Rate be Used for Evaluating a Tolling Agreement than Used for a Renewable Energy Contract?" *Electricity Journal*. Volume 9, Issue 21. November 2008, p. 40, as presented in Attachment K.
[53] Susan Tierney and Todd Schatzki. July 2008, p. 28, as presented in Attachment H.

affiliate offers), and complete evaluations in a timely and efficient fashion to provide proper incentives for bidders."[54]

- In a 1993 *Electricity Journal* article, Susan Morse and Meg Meal discussed the need for all risks associated with a utility build option to be included in the utility build price when UOG offers compete against PPA offers in order to provide an even playing field.[55]

Q. IS THERE PRECEDENT FOR CONSIDERING RISK AS PART OF A BID PRICE?

A. Yes. For example, as part of Pacific Gas & Electric (PG&E)'s proposed reorganization during its bankruptcy proceeding, the Federal Energy Regulatory Commission required PG&E's proposed generation spinoff ("Gen") to "benchmark the PSA's non-price contractual terms against the comparison group. This included analyzing the assignment of responsibilities and risks and the consequences of non-performance by the parties. Gen compared the non-price terms of its PSA with those of typical, arms-length bilateral sales agreements. The terms evaluated included availability risk (a measure of reliability), fuel price risk, dispatch control, hydrologic risk, and Diablo Canyon facility security risk."[56]

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[54] Susan Tierney and Todd Schatzki. July 2008, p. 28, as presented in Attachment H.
[55] Susan Morse and Meg Meal. "Balancing Incentives in a Competitive Marketplace." *Electricity Journal.* August/September 1993, pp 30-31, as presented in Attachment L.
[56] C. K. Woo. "Benchmarking The Price Reasonableness Of A Long-Term Electricity Contract" *Energy Law Journal*, Volume 25 (2004), p. 373, as presented in Attachment M.

Q. ARE BID ADDERS BEING CONSIDERED IN OTHER JURISDICTIONS TO MORE FAIRLY COMPARE BIDS FOR UOG AND IPP PROJECTS?

A. The Oregon Public Utilities Commission has an open proceeding to develop an approach for a quantitative analysis of the comparison between UOG and IPP project risks, "including consideration of construction risks, operation and performance risks, and environmental regulatory risks."[57] Parties to the proceeding have proposed various risk adders that could be applied. Commission approval is pending.

Q. DO YOU RECOMMEND THAT BID ADDERS BE USED IN PSCO RFPS?

A. My primary recommendations are that PSCo not be allowed to bid UOG project in this solicitation, and, if a solicitation fails, that ratemaking for PSCo for the first ten years of UOG operations be set based on the cost and performance assumptions used in the UOG bid. These two approaches are straightforward to implement, and they incentivize more accurate bid development by PSCo, level the playing field between UOG and IPP projects, and reduce customer risk. However, if the Commission declines to adopt either of these approaches, I recommend that bid adders be used to explicitly address the risk differential between UOG and IPP projects during bid evaluation. This is a secondary recommendation because it doesn't incentivize more accurate bid development by PSCo, it doesn't fully address the risk differential between UOG and IPP proposals, and it doesn't protect customers from UOG cost overruns. It is only a partial measure to start to level the playing field between UOG and IPP projects,

[57] Oregon Public Utilities Commission Order 11-001, reopening Docket UM 1182, January 3, 2011, page 6, as presented in Attachment N and at http://apps.puc.state.or.us/orders/2011ords/11-001.pdf.

Q. IF YOUR SECONDARY RECOMMENDATION IS ADOPTED, HOW DO YOU PROPOSE THAT UOG PROJECT BIDS BE ADJUSTED?

A. I recommend that PSCo's bids for UOG projects be adjusted as follows to reflect the differential risk to ratepayers from cost-of-service ratemaking:

1. Heat rate projections should be increased by 10.3%; and
2. Fixed O&M cost projections should be increased by 166%.

The derivation of these adders is discussed in Appendix A.

Q. SHOULD THESE ADDERS BE APPLIED TO ALL UOG BIDS?

A. I recommend that these adders apply to all UOG proposals for which customers are at risk for cost increases during the first ten years of operations. If, however, rate recovery during these years will be based on costs and performance in the UOG bid, or if PSCo is ineligible to bid, no bid adders should apply.[58]

Q. DO YOUR PROPOSED RISK ADDERS ACCOUNT FOR THE ENTIRE RISK DIFFERENTIAL BETWEEN UOG AND IPP PROJECTS?

A. No. There are many risk elements that are not addressed by my proposed adders, since data and time limitations restricted my analysis to the factors that I examined. To fully account for the risk differential, adders should also be developed to account for all other risks, including:

1. Risk of higher capital costs;
2. Operational risks that reduce market values (e.g., plant availability, longer-than-expected ramp rates, life of project);

[58] It might be appropriate to include adders for IPP projects based on the uncertainty in IPP project costs and performance if ratepayers would be at risk for the cost increases.

3. Risk of higher transmission costs;
4. Risk of higher fuel costs;
5. Risk from fuel availability exposure;
6. Risk from greenhouse gas cost exposure; and
7. Congestion risk.

If fuel availability risk is a significant concern, PSCo could additionally assign risk adders to bids that would impose a greater fuel availability risk for ratepayers. In theory, all project risks should be quantified and added to the bid amounts to help identify the true project costs.

In addition, the variance in potential costs from a bid should be assessed. If a UOG project uses cost-of-service ratemaking for cost recovery (i.e., without setting rates in the first ten years based on bid assumptions) and an IPP's fixed costs and operating characteristics are fully specified in the project's PPA, then there is significantly greater uncertainty with regard to the UOG project's costs than the IPP project's costs. A bid evaluation that does not take this cost variance into account could select a project that creates higher costs for ratepayers than competing projects with more firm bids.

The two risk adders proposed in this testimony are plainly just a small step towards addressing the significant risk differential between UOG and IPP project bids. Additional measures are needed to more fully level the playing field and to help restore Colorado's competitive balance. If the Commission declines to make UOG projects ineligible to bid in PSCo's RFOs and declines to set cost recovery for the first ten years of UOG projects based on the cost and performance characteristics in the UOG bids, the remaining risk differential should be addressed in a new Commission rulemaking that is opened upon the culmination of this proceeding for the purpose of developing additional risk adders.

4. CONTINGENCY PLAN ALTERNATIVES

Q. DOES PSCO'S ERP ADDRESS CONTINGENCIES IN RESOURCE PLANNING AND ACQUISITION THAT COULD RESULT IN A CAPACITY SHORTFALL?

A. Yes. PSCo identifies the following potential contingency events:

1. Failed contract negotiations with winning bidders;
2. Bidders withdrawing proposals;
3. Bidders seeking revised terms from those in their bid;
4. Project development delays or cancellation;
5. Transmission development delays; and
6. Higher than anticipated electric demand.[59]

Q. HOW DOES PSCO PROPOSE TO ADDRESS CONTINGENCIES THAT WOULD RESULT IN A CAPACITY SHORTFALL?

A. PSCo proposes a hierarchy in which the company would first use alternative bids from bidders whom PSCo had not yet released from their obligation. PSCo identifies this alternative as being most appropriate for replacing 1st winning bids that do not reach successful contract completion. The next alternative identified by PSCo is to negotiate the acceleration of the in-service date for a resource that has been contracted. PSCo

[59] PSCo 2011 ERP, Volume 1, page 1-59.

characterizes this alternative as being appropriate for a one-to-two year delay in another resource. The third alternative proposed by PSCo (and the first alternative to address situations other than the failure of a selected resource to complete a contract or the delay of a contracted resource) is for PSCo to self-build using the back-up bid filed by PSCo. The final long-term supply option is to substitute the PSCo self-build with a sole source procurement with a "reliable supplier." A reliable supplier would be an IPP with whom PSCo has a "good working relationship" and who is able to supply from an existing facility or an expansion of an existing facility.[60]

Q. ARE THERE PROBLEMS WITH PSCO'S PROPOSED HIERARCHY OF CONTINGENCY ALTERNATIVES?

A. Yes. PSCo's hierarchy essentially puts the company self-build proposals at the top of the queue for responding to some of the contingencies (e.g., higher than expected demand) and creates an incentive for PSCo to quickly clear out the pool of available bidders during contract negotiations. In effect, PSCo has an incentive to create a contingency by taking negotiating positions that cause bidders to drop out, which has the additional benefit to PSCo of placing its self-build proposals next in line to resolve the resulting capacity shortage problem.

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[60] PSCo 2011 ERP, Volume 1, page 1-62.

Q. WHAT IS YOUR PROPOSAL FOR ADDRESSING CAPACITY SHORTFALL CONTINGENCIES THAT WOULD BE ADDRESSED WITH NEW RESOURCES?

A. PSCo should be required to procure all resources, including contingency alternatives, on a competitive basis. The default approach should be to rely on the bids it received through the initial RFP. If, at the time the contingency is recognized, the pool of available bids has been depleted, or sufficient time has passed that the bids are stale, PSCo should be required to provide the opportunity for bidders to resubmit and refresh their bids. Bid selection for contingency alternatives should be performed using the same evaluation process approved in this docket for the initial RFP.

5. CAPITAL LEASE

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. This section discusses issues related to PSCo's intent to assess future PPAs using new lease accounting standards that are expected to be released by the Financial Accounting Standards Board (FASB) in the second half of 2012. PSCo contends that the new lease accounting standard "...would require that all transactions classified as leases be given financial statement recognition as lease assets and lease obligations."[61] Currently, only certain capital leases require such balance sheet recognition.

[61] Supplemental Direct Testimony of Christopher R. Howarth, Docket No. 11A-869E, February 13, 2012, page 2.

Q. WHAT IS PSCO PROPOSING?

A. PSCo is proposing to assess PPAs during negotiations based on the applicable FASB lease accounting standard (i.e., using the lease accounting standard in effect as of the year being assessed). In his supplemental testimony, Dr. Haworth clarified that "[i]f a new standard is issued, the Company will assess the PPA using the lease standards that will be in effect both before and after the effective date of the new standard, in order to identify all accounting standards." [62]

Q. HOW WOULD THE USE OF ONE LEASE ACCOUNTING STANDARD OR ANOTHER AFFECT PPA BID EVALUATION?

A. It is unclear from PSCo's ERP how it intends to apply a new lease accounting standard when "assessing" a PPA. However, the Company does state that it "...is generally interested in avoiding capital leases due to the potentially negative effect that capitalization of lease assets and obligations [could have] on the Company's books...."[63] It is possible that if the new lease standard results in PPAs being treated in the same manner as capital leases, PSCo may attempt to increase the costs associated with such PPAs during bid evaluation so as to avoid taking on the obligation.

[62] Supplemental Direct Testimony of Christopher R. Howarth, Docket No. 11A-869E, February 13, 2012, page 4.

[63] PSCo 2011 ERP, Volume 2, page 2-37

Q. DID PSCO PROVIDE A TIMELINE FOR THE RELEASE OF THE FINAL LEASE STANDARD IN ITS REP APPLICATION?

A. Yes. PSCo's initial ERP filing in October 2011 stated, "A revised lease standard is expected to be introduced in the fourth quarter of 2011 (and effective in approximately 2015)…."[64]

Q. WAS THE REVISED STANDARD ISSUED IN 2011?

A. No. The revised standard was not issued in 2011. In the supplemental testimony filed in February 2012, Dr. Haworth stated that "[i]f the exposure draft is distributed during the second quarter of 2012 it is possible that a final standard would be issued in early 2013 and effective in 2015 or 2016".[65]

Q. DOES PSCO BELIEVE THAT THIS REVISED SCHEDULE IS STILL APPROPRIATE?

A. No. In response to data requests, Dr. Haworth provided an updated timeline: "Given the change in the timeline from the end of 2011 to mid-to-late 2012 for the issuance of the Lease Exposure Draft, we now expect that a final standard would likely not be effective until at least the beginning of 2016, although this has not been formally documented."[66]

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[64] PSCo 2011 ERP, Volume 2, page 2-41.
[65] Supplemental Direct Testimony of Christopher R. Howarth, Docket No. 11A-869E, February 13, 2012, page 3.
[66] PSCo response to CIEA/CEC/Thermo data request 2-16 a, as presented in Attachment O.

Q. GIVEN THE UNCERTAINTY OVER THE TIMELINE FOR ISSUANCE OF NEW LEASE ACCOUNTING STANDARDS, HOW DOES PSCO PROPOSE TO APPLY NEW LEASE STANDARDS WHEN IT ASSESSES PPAS DURING THE INTERIM PERIOD BEFORE THE NEW STANDARDS, IF ISSUED, TAKE EFFECT?

A. PSCo stated that it must comply with the new lease standards after the effective date of the standard. Until then, the existing lease standard will be applicable for PPAs, including during the interim period between the issuance and the effective date of the new lease standard. PSCo has elaborated this approach below:

> Once a new lease standard is issued, there will be a time period prior to the effective date that the guidance from the existing lease standard would need to be followed (i.e. a final standard could be issued in 2013 and be effective starting in 2016. The existing lease accounting standard would need to be followed during 2013-2015, then the new lease accounting standard would need to be followed in 2016 (however, there may be retrospective accounting implications for 2014-2015) through the remainder of the PPA).[67]

Q. HOW DO MOODY'S AND STANDARD AND POOR'S CURRENTLY TREAT OPERATING LEASES IN ANALYZING THE RATINGS FOR THE UTILITY'S DEBT OFFERINGS?

A. While operating leases are not currently reflected on the utility's balance sheet, both rating agencies adjust the utility's financial statements to impute debt related to the operating leases. Even with the imputed debt from the operating leases, both of these

[67] PSCo response to CIEA/CEC/Thermo data request 2- 17b, as presented in Attachment O.

ratings agencies have an "A" rating on this utility. It is uncertain what impact, if any, any new accounting standard would have on the ratings agencies' analysis.

Q. ARE THERE PROBLEMS WITH PSCO'S APPROACH?

A. Yes. There are three main concerns:

1. There is uncertainty related to the timing of the release of FASB's final lease standards. Initially, PSCo stated that a revised lease standard would be introduced in the fourth quarter of 2011. The release of this revised lease standard has been delayed twice. Thus, it is not clear exactly when FASB will release even an exposure draft;
2. If an exposure draft is issued during the resource procurement process, PSCo is proposing to "assess" (or "model") projects using both the old and new lease accounting standards.[68] It is not clear precisely how PSCo would use the results of this "modeling" using the new lease accounting standard in potential negotiations with IPPs, but there is the potential for such "modeling" to incentivize PSCo to view IPPs less favorably relative to company-owned proposals; and
3. PSCo is unsure whether or when it would submit a proposal to the Commission for approval of PSCo's proposed assessment methodology for the new standard's impact on its evaluation of PPAs.[69]

[68] PSCo response to CIEA/CEC/Thermo data request 2-18a, as presented in Attachment O and Supplemental Direct Testimony of Christopher R. Howarth, Docket No. 11A-869E, February 13, 2012, page 4.
[69] PSCo response to CIEA/CEC/Thermo data request 2-17c, as presented in Attachment O.

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. My recommendations are the following:

1. Signed PPAs and PPAs under negotiation should not be affected by the new draft lease standards that may be issued during any solicitation resulting from the current ERP; and
2. The Commission should require PSCo to submit an application that specifies in detail how PSCo plans to apply any new lease accounting standards in its evaluation of PPAs. Such an application may be filed only after the final lease accounting standard has been issued. Depending on when the final standard is issued, PSCo's application could be incorporated in a future ERP or as a stand-alone application. Parties should have an opportunity to review and provide feedback regarding PSCo's proposed approach. The Commission should issue a decision on this matter on an expedited basis.

6. <u>COMMUNICATION WITH BIDDERS</u>

Q. WHAT SORT OF COMMUNICATION WITH PSCO SHOULD BIDDERS HAVE?

A. PSCo should provide each bidder with the assumptions that PSCo used in evaluating that bidder's own bids, such as project operating parameters, transmission interconnection costs, gas supply costs, and wind integration costs. Both the Colorado Legislature (through H.B. 11-1262) and the Commission have recognized that transparency and the ability to correct any errors in the characterization of bids are essential attributes to successful competition.

Q. DOES PSCO PLAN TO PROVIDE SUCH INFORMATION TO BIDDERS?

A. Yes. PSCo plans to provide this information to bidders (with respect to their own bids), but only after initial bid screening and prior to Strategist modeling.[70] In other words, PSCo would screen out certain projects from evaluation first and only then provide bidders with the information upon which the Company based its decisions to exclude their project.

Q. IS THIS A REASONABLE APPROACH?

A. No. It is essential that bidders learn what assumptions will be used to evaluate their bids prior to the initial screening. This is necessary in order to provide bidders with the opportunity to correct any mistakes in these assumptions before their bids are screened. If bids are screened based on incorrect assumptions, PSCo could erroneously reject bids for projects that would best satisfy customer needs, and it would be too late to rectify the error once the bid is rejected.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that PSCo provide bidders with the assumptions that will be used in evaluating their own bids ten days prior to bid screening. During this ten-day period, bidders should have the opportunity to review and, if necessary, correct PSCo's assumptions. In the event that a bidder and PSCo cannot come to agreement as to the value of a particular assumption about the bidder's project, the bid screening should be deferred by up to 15 days, during which time the Independent Evaluator should make a determination as to the appropriate input assumption.

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[70] PSCo's 2011 ERP, Volume 1, page 1-72.

7. MODEL PPA TERMS SHOULD NOT UNREASONABLY RESTRICT BIDS AND COMPETITION

Q. DO CERTAIN TERMS OF THE PSCO MODEL PPA DISADVANTAGE CERTAIN IPPS RELATIVE TO UOG PROJECTS?

A. Yes. Based on advice of counsel, I understand that the Model PPA attempts to restrict or dictate IPPs' flexibility to finance their facilities. These provisions in the Model PPA can interfere with and increase the price of finance, reducing the number of competitive bids and/or increasing bid prices.

Q. CAN YOU PROVIDE SPECIFIC EXAMPLES?

A. Yes. PSCo has revised the definition (from the last model PPA approved by the Commission in the 2007 ERP process) of "Portfolio Financing" (page A-11) to limit the flexibility of IPPs in their ability to structure financing arrangements. It appears that PSCo's revisions attempt to exclude any financing arrangement that cross-collateralize the subject facility of the IPP with its other assets where: (i) PSCo or its affiliates are purchasers of the output of any of the IPP's other generating assets, (ii) the purchasers of the output of any of the IPP's other generating assets do not have at the minimum an unsecured bond rating of Investment Grade or substantially equivalent financial wherewithal; and (iii) the IPP's other generating assets are not all located in the United States or do not generate energy as their primary business.

Q. WHY MIGHT PSCO BE CONCERNED ABOUT THIS FORM OF FINANCING?

A. It is possible that PSCo is concerned about cross-default scenarios that could place an IPP's contracted assets at risk. However, I am not aware of any explicit justification by PSCo in its ERP supporting its proposed change in the Model PPA.

Q. HOW DOES THIS PROVISION DISADVANTAGE IPPS RELATIVE TO UOG PROJECTS?

A. This narrowed definition of what PSCo considers permissible portfolio financing unreasonably restricts the scope of assets that might be bid into PSCo's Phase II RFP. This limitation could effectively exclude bids from IPPs that currently have, or may at some time in the future might use, portfolio financing.

Q. WHAT DO YOU RECOMMEND?

A. The Commission should exclude this limitation in the Model PPA. PSCo has given no justification for such a limitation on IPP financial structures and has not shown how such a change would provide any real or perceived benefit to ratepayers. Instead, this provision could reduce the number of qualified and low cost bids in the Phase II RFPs, which could harm ratepayers through reduced competition. Even if PSCo is concerned about cross-default scenarios that could place an IPP's contracted assets at risk, I am advised that there are other methods to address this concern short of restricting use of this commonplace financing solution. For this reason, the Commission should reject PSCo's proposed change to this provision in the Model PPA.

8. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My recommendations are as follows:

1. The Commission should require PSCo to use competitive solicitations if it decides to make "opportunistic" resource acquisitions outside of the ERP process;
2. IPP contract terms must be appropriately considered in the bid evaluations. To do so, PSCo should change its approach for assessing the true cost of IPP resources over the life of those assets;
3. UOG projects should not be allowed to compete with IPP projects in PSCo's power solicitations and should be allowed only in the case of an RFP failure, especially in this case where there is a wide range of IPPs to meet forecast needs for capacity during the life of this ERP;
4. If a UOG project is built, rate recovery for the project for the first ten years of the project's life should be set based on the cost and performance assumptions used in its competitive bid or Commission application for the project;
5. If the Commission does not adopt my recommendation to hold UOG projects to their bid cost and operational characteristics for the first ten years of plant operations, then the evaluation of bids for UOG and IPP resources should account for the differential in ratepayer risk between UOG and IPP projects;
6. PSCo should be required to procure all resources, including contingency alternatives, on a competitive basis;

7. The Commission should not penalize IPPs for unknown or potential lease accounting standards which may or may not be issued;
8. The Commission should require PSCo to submit an application that specifies in detail how PSCo plans to apply any new lease accounting standards in its evaluation of PPAs;
9. To fully implement the Legislature's expressed desire to ensure transparency and accuracy in bid evaluation, bidders should be given an opportunity to correct potential errors in assumptions proposed to be used by PSCo in bid evaluations prior to a final decision on whether the bid should pass the initial screening; and
10. PSCo should not be allowed to impose unnecessary PPA limitations that have the effect of reducing competition.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A: Development of Bid Adders

Q. HAVE YOU DEVELOPED ADDERS TO ACCOUNT FOR THE DIFFERENCE IN RISK PROFILES BETWEEN UOG AND IPP PROJECTS?

A. I have estimated two sets of adders to address some of the incremental uncertainty in ratepayer costs for UOG projects relative to PPAs. The adders relate to (1) changes in performance relative to the project's initial performance expectations, and (2) changes in O&M costs relative to the project's initial estimates. These adders are discussed further below.

Q. HAVE YOU DEVELOPED SIMILAR FACTORS TO ACCOUNT FOR THE UNCERTAINTY IN IPP PROJECT COSTS?

A. No. I have assumed that IPPs bear the full risk for performance characteristics and O&M costs for their projects. If a PPA were structured to assign some of these risks to ratepayers, adders could be assigned to the appropriate cost elements to reflect this risk.

a) Performance degradation adder

Q. WHY IS A PERFORMANCE DEGRADATION ADDER NEEDED?

A. Performance degradation can come in many forms: for example, heat rates can degrade faster than expected, ramp rates could be longer than expected, and outages can be more frequent than expected. These sorts of degradation increase direct costs, such as costs for fuel and repairs, and also impose indirect costs, such as the cost of environmental compliance required for the additional fuel that is burned when heat rates rise, the cost of ancillary services needed when the UOG project has lower-than-expected operational flexibility, and the cost of replacement power during prolonged outages. Technological obsolescence can also be seen as performance degradation, since the plant's degraded operational characteristics relative to newer technologies reduce the plant's value.

Performance degradation is natural over time and is generally accounted for to a certain extent in the development of UOG and IPP project bids. However, there is a risk that degradation may be faster or start sooner than expected. When this occurs in an IPP projects, PSCo's customers are generally fully protected, since the IPP is bound to continue supplying power at the PPA price regardless of the plant's actual costs and performance. If the plant degrades to such an extent that the IPP can no longer honor the contract, the IPP must pay damages to PSCo to cover PSCo's replacement power costs or the contract could be terminated. These contract provisions protect PSCo ratepayers from the risk of unexpectedly high performance degradation.

No such protections exist for UOG projects. Increases to fuel costs and maintenance costs due to heat rate and other performance degradation are generally passed through directly to ratepayers. Ratepayers would also bear the increased costs that would result from a UOG project being less flexible or less available than expected. UOG projects therefore pose an incremental risk to ratepayers not present in IPP projects.

Q. HAVE YOU DEVELOPED A BID ADDER TO ACCOUNT FOR ALL TYPES OF PERFORMANCE DEGRADATION?

A. No. I have developed a bid adder that accounts only for heat rate degradation. Other types of performance degradation can also be costly and their risk to ratepayers should also be assessed. However, given limitations of time and data, I limited my analysis to heat rate degradation.

Q. HOW DID YOU DERIVE THE ADDER FOR CHANGES IN HEAT RATES?

A. I used a public database of annual financial data and performance characteristics of U.S. utility-owned generation that covers the years 1981 through 1999.[71] I extracted from the database the annual heat rates for all gas-fired generation of at least 150 MW for which the database includes at least three data points over the 19-year period.[72] The resulting dataset includes data for 194 plants.

I would have liked to compare the heat rate for each plant in each year to the heat rate assumed when the project received regulatory approval or, absent that data, the starting heat rate for the plant. However, neither of these data was readily available. I therefore used the minimum heat rate observed in the dataset as a conservative proxy for the expected/starting heat rate. This is a conservative proxy since it may already include significant heat rate degradation from the years prior to 1981.

I compared the annual heat rate recorded in the dataset for each plant to the minimum recorded heat rate for the plant, and I used the average of these changes for each plant as a proxy for the change in average heat rate over the plant lifetime compared to the expected heat rate. This inserts further conservatism into the analysis, since in most cases

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[71] Data files for Fabrizio, Rose, and Wolfram. "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency." *American Economic Review*, 2007, Vol. 97 (September): 1250-1277. Available at http://faculty.haas.berkeley.edu/wolfram/.

[72] I excluded data points that showed heat rates of less than 7,000 Btu per kWh, since these likely represent typographical errors.

the plant lifetime extends beyond the years shown in the dataset, and further degradation beyond that observed in the dataset is likely.

I averaged together all the observed heat rate changes across all the plants to develop a proxy for the average heat rate increase above the expected heat rate, with a value of 10.3%. This 10.3% value should be used as the heat rate adder.

Q. HOW SHOULD THIS ADDER BE APPLIED?

A. If ratepayers would be at risk for the higher costs associated with heat rate degradation, the expected heat rate increase must be incorporated in the bid evaluation. This can be done as a 10.3% heat rate adder or as a heat rate forecast that reflects anticipated degradation resulting in a 10.3% increase in the levelized heat rate over the bid evaluation period. If the utility provides a heat rate forecast showing degradation of less than 10.3% over time, the 10.3% adder should be adjusted so that the degradation included in the heat rate forecast plus the additional heat rate adder sum to a 10.3% increase in the levelized heat rate over the bid evaluation period.

Q. WHY DID YOU RELY ON THE PUBLIC DATABASE OF POWER PLANTS THROUGHOUT THE U.S. INSTEAD OF PERFORMANCE INFORMATION FROM PSCO'S PLANTS?

A. On April 5, 2012, I requested information from PSCo regarding the actual heat rates of all the gas-fired plants developed or purchased by PSCo or an affiliated Xcel company.[73]

[73] PSCo response to CIEA/CEC/Thermo data request 2-1 J, as presented in P.

However, as of May 31, 2012, I had not received this information from PSCo.[74] As a result, I relied exclusively on the nationwide database to develop my proposed heat rate adder for UOG projects.

b) Fixed O&M adder

Q. WHY IS A FIXED O&M ADDER NEEDED?

A. O&M costs can increase for any number of reasons including unexpected maintenance, increases to labor costs, capital additions, and component wear. In addition, routine O&M may be more time-consuming or expensive than expected, unanticipated regulations may increase or complicate maintenance requirements, and unexpected capital additions may incur ongoing maintenance costs.

For thermal plants, environmental regulations can be a major O&M cost driver. The U.S. Environmental Protection Agency (EPA) estimates that scrubbers to reduce sulfur dioxide emissions from coal plants increase O&M costs by up to $300 per kW depending on scrubber type and plant size.[75] The EPA also estimated that compliance with its new plant "section 316(b)" cooling water intake requirements would increase O&M costs for combined cycle plants between 3% and 36% and for coal plants between 1% and 54% depending on the plant's initial configuration.[76] UOG projects subject to these regulations

[74] PSCo responded to the bulk of this data request on May 25, 2012. This response stated that the requested data on actual heat rates would be provided separately in a highly confidential attachment. PSCo Response to CIEA/CEC/Thermo data request 2-1 J, as presented in Attachment P.
[75] EPA. Air Pollution Control Technology Fact Sheet on Flue Gas Desulfurization – Wet, Spray Dry, and Dry Scrubbers, EPA-452/F-03-034, page 2, Table 1b, as presented in Attachment Q.
[76] EPA. Section 316(b) TDD Chapter 2 for New Facilities: Costing Methodology, Table 2-6 on page 2-16, as presented in Attachment R.

that did not anticipate these increases in O&M costs could ultimately cost ratepayers significantly more than originally expected.

Q. HOW DID YOU DERIVE THE ADDER FOR FIXED O&M COSTS?

A. I developed the fixed O&M adder for thermal plants using the dataset of gas-fired plants of at least 150 MW obtained from the database of historic utility generation costs and operating characteristics discussed above.[77] The database did not disaggregate fixed and variable O&M costs but instead included a value for total non-fuel plant O&M costs. In order to obtain an estimate of fixed O&M costs, I assumed a variable O&M cost of $1.50 per MWh and subtracted this from the total non-fuel O&M cost for each plant.[78] From these new data, I derived percentage changes in fixed O&M for each plant compared to the minimum fixed O&M cost observed in the dataset for that plant (on a real dollar basis). As with the heat rate analysis, I used this as a proxy for the change in average fixed O&M costs over the plant lifetime compared to the expected fixed O&M costs. The same conservatisms discussed with regard to the heat rate analysis apply equally here.

I averaged together all the observed fixed O&M cost changes across all the plants to develop a proxy for the average fixed O&M cost increase above the expected fixed O&M cost, with a value of 166%. This 166% value should be used as the fixed O&M adder. For the purposes of bid evaluation, this adder should be added to the fixed O&M costs

[77] As with the heat rate analysis, I excluded plants for which there were fewer than three data points. I also eliminated one plant (Permian Basin) that had too many questionable data points. Including this plant would have increased the fixed O&M adder.

[78] For 1.5% of the data points, subtracting off $1.50 per MWh resulted in a negative O&M value. For the three plants for which more than 1/3 of their data points became negative upon this subtraction, I used the full O&M cost for all data points, assuming that variable O&M costs were not being reported in their O&M costs. For other plants, I excluded any negative values from the analysis and treated the remaining data points consistent with a variable O&M cost of $1.50 per MWh.

stipulated in any proposals that would put ratepayers at risk for direct pass-through of unexpected increases in fixed O&M costs.[79]

Q. WHY DID YOU RELY ON THE PUBLIC DATABASE OF POWER PLANTS THROUGHOUT THE U.S. INSTEAD OF PERFORMANCE INFORMATION FROM PSCO'S PLANTS?

A. I requested information from PSCo regarding the O&M costs of all the gas-fired plants developed or purchased by PSCo or an affiliated Xcel company, specifically requesting the initial estimate provided to the regulator, the estimate approved by the regulator, and actual historic values.[80] I had hoped to assess the difference between projected and actual O&M costs at these plants.

While PSCo provided information in response to this request, the information was not sufficient for performing this analysis for two reasons: (1) for most of the plants, the information on expected O&M costs was specific to one or two units of the power plant (i.e., the units that were recently built or repowered) while the actual O&M data covered the power plant in its entirety, and/or (2) the documentation provided from prior to the plant's construction (e.g., application to the Commission, Commission decision or order) did not specify the expected O&M costs.[81]

[79] If the UOG proposal includes a guaranteed level of non-fuel O&M costs, then the adder should not be applied during bid evaluation.
[80] CIEA/CEC/Thermo data request 2-1 d-e and PSCo response, as presented in Attachment P.
[81] PSCo response to CIEA/CEC/Thermo 2-1 d-e, as presented in Attachment P.

The information provided by PSCo was also insufficient to develop a trend of changes to O&M costs over time because the data provided for most of the plants covered just a few years and, in many cases, these data incorporated both older units and newer units (or newly repowered units) at a single plant.

For these reasons, I was unable to use information from PSCo or Xcel in developing the O&M bid adder, and so I relied exclusively on the nationwide database to develop my proposed O&M adder for UOG projects.