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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS	)	**CASE NO. IPC-E-15-01**
IN THE MATTER OF AVISTA CORPORATION'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS	)	**CASE NO. AVU-E-15-01**
IN THE MATTER OF ROCKY MOUNTAIN POWER COMPANY'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS	)	**CASE NO. PAC-E-15-03**

Idaho Conservation League and the Sierra Club

Direct Testimony of R. Thomas Beach

April 23, 2015

IPC-E-15-01
BEACH, Di
Idaho Conservation League and Sierra Club

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Idaho Power has filed a Petition asking the Commission to reduce from 20 years to two years the term of power purchase contracts with large renewable generation projects developed in its service territory under the Public Utilities Regulatory Policies Act (PURPA). Idaho Power is concerned that, if the 20-year term is retained, it may have to execute up to 885 MW of additional contracts with solar projects in Idaho. The utility has expressed concerns with the lack of need, the cost, and the system reliability impacts of this additional renewable generation.

The Idaho Conservation League and the Sierra Club oppose Idaho Power's Petition. First, it is clear that the intent of the utility's Petition is to make it impossible to finance additional solar projects in its service territory. Capital-intensive solar projects cannot be financed with two-year contracts. It is questionable whether such a step complies with the legal requirements of PURPA to encourage the development of qualifying renewable generation that can be developed at the utility's avoided costs. If Idaho Power does not want to comply with its PURPA obligations, there are well-established ways for the utility to replace its traditional PURPA obligation and for the state of Idaho to assume greater control over utility procurement of renewable generation in the state. However, these alternative means will require fundamental changes to the energy markets in Idaho.

Second, the prices in PURPA contracts are set based on the utility's avoided costs, that is, on the costs that the utility would incur for the same amount of power if it did not purchase the PURPA generation. As a result, Idaho Power's ratepayers will be indifferent, on a forecast basis, to the purchase of the additional solar generation. Idaho Power claims that it is too risky and unnecessary to make these long-term commitments. This testimony responds to these arguments, and shows that this fixed-price renewable generation will offer significant benefits to Idaho Power's ratepayers in addition to avoiding higher cost power, including:

- **Low-priced solar generation.** There is a limited window of opportunity for Idaho Power to purchase low-cost solar generation before the 30% federal investment tax credit expires at the end of 2016.

- **REC sales revenues.** Idaho Power will gain additional revenues from the sale of the renewable energy credits (RECs) associated with this power, or, alternatively, from reduced costs to comply with future regulations limiting the carbon emissions from Idaho Power's system.

- **Hedging benefits.** Fixed-price power hedges against future volatility in energy market prices.

- **Lower market prices.** Zero-variable-cost renewable generation will reduce energy market prices in the West generally.

- **Capacity options.** The solar generation will provide a new capacity option that will have value if existing coal-fired capacity is retired earlier than expected.

- **Economic development.** The potential solar projects represent an investment of about $2.7 billion in clean energy infrastructure in Idaho Power's service territory in the near future, thus providing economic benefits associated with this new development of modern clean energy facilities.

This testimony quantifies each of the above benefits. These significant benefits, combined with the avoided cost pricing for the additional solar generation, mean that this generation will offer significant net economic benefits to energy consumers in Idaho, regardless of whether this renewable generation serves Idaho consumers or helps neighboring states to comply with their renewable portfolio standards.

ICL and the Sierra Club also address Idaho Power's concerns with the system reliability impacts of additional solar generation. Significant studies have been conducted in recent years of the operational and reliability impacts of integrating high levels of wind and solar generation on the Western Electricity Coordinating Council (WECC) grid. A much higher penetration of solar generation is feasible in the WECC than what would result from these solar contracts. Changes in the energy markets in the WECC already are underway to facilitate renewables integration, such as the energy imbalance market that began operations in November 2014. By the end of 2015, utilities that operate in all of the states that neighbor Idaho will be participating in this market.

The Commission's IRP method for setting avoided cost prices provides for regular updates of avoided cost prices to reflect changing loads, natural gas prices, and the need for generation. As a result, the avoided cost prices for solar have declined as additional PURPA generation has been added. Further updates of these prices are likely before the additional solar is approved, which is likely to result in even lower prices. At the indicative prices for the additional solar generation, Idaho Power will be obtaining this renewable generation at a reasonable price compared to solar contracts elsewhere in the U.S.

Finally, ICL and Sierra Club suggest that the Commission consider changing the IRP method to allow more frequent updates to Idaho Power's capacity position. This would produce even more accurate avoided cost pricing in the future, and at least partially address Idaho Power's concerns in this regard.

I. INTRODUCTION

Q: Please state your name, address, and business affiliation.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: I have over 30 years of experience in utility analysis, resource planning, and rate design. I began my career at the California Public Utilities Commission, working from 1981-1984 on the initial implementation in California of the Public Utilities Regulatory Policies Act (PURPA) of 1978. I then served for five years as an advisor to three CPUC commissioners. Since entering private practice as a consultant in 1989, I have served as an expert witness in a wide range of utility proceedings before many state utility commissions. This includes sponsoring testimony on PURPA-related issues in state regulatory proceedings in California, Oregon, Nevada, North Carolina, and Vermont. Prior to this experience, I earned degrees in English and Physics from Dartmouth College and a Masters in Mechanical Engineering from the University of California, Berkeley. My curriculum vita is attached to this testimony as Exhibit ICL/SC-301.

Q: On whose behalf are you testifying in this proceeding?

A: I am appearing on behalf of the Idaho Conservation League (ICL) and the Sierra Club.

ICL intervened in this case due to ICL's continuing interest in the development of clean, indigenous energy resources in Idaho through various means, including energy sales agreements between independent developers and electric utilities under PURPA. Such development can ensure that Idaho's electric system provides reliable, fair-priced service that protects the clean air, clean water, and stable climate that are foundational public values for Idahoans. Accordingly, ICL has a strong interest in the major change the Idaho utilities propose in the terms of their PURPA agreements.

The Sierra Club is a national, non-profit environmental and conservation organization dedicated to the protection of public health and the environment. Sierra Club has joined with ICL in this case on behalf of itself and nearly 2,400 Sierra Club members who live and purchase utility services in Idaho. Sierra Club's Idaho members have a direct and substantial interest in this proceeding as a result of its potential impact on additional solar deployment in Idaho and on the environmental, health and economic benefits that would result from the addition of this renewable generation to the Idaho electric system.

Q: Have you previously testified or appeared as a witness before the Idaho Public Utility Commission?

A: Yes, I have. I testified on behalf of ICL in Case No, IPC-E-12-27 concerning proposed changes to Idaho Power's net metering service.

Q: Do you have any exhibits?

A: Yes. Exhibit ICL/SC-301 is my curriculum vitae. Exhibit ICL/SC-302 are certain discovery responses from Idaho Power. Exhibit ICL/SC-303 is a fact sheet about the new Energy Imbalance Market involving PacifiCorp, the California Independent System Operator (CAISO), Puget Sound Electric, and NV Energy.

II. BACKGROUND ON PURPA

Q: Idaho Power's Petition generally describes the requirements of PURPA. Do you have anything to add to this background?

A: Yes. ICL Witness Adam Wenner provides a more detailed legal analysis. As a consultant with over 35 years of experience in this field, I offer the following economic perspective. Congress enacted PURPA to encourage a new, free market for the independent development of generation from resources that would reduce our nation's dependence on fossil fuels, with the goal of increasing the energy security and independence of the U.S. PURPA required public utilities, who enjoyed a state-sponsored monopoly in the generation market, to purchase power from cogeneration and small renewable power producers, collectively called "qualifying facilities" or QFs, at prices that could not exceed the utilities' "avoided cost." In the words of the statute, avoided costs are "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source."[1] PURPA's must-take requirement at an avoided cost price was intended to offset the monopsony power of the utility as the sole buyer of generation in its service territory. Congress limited purchase price to the utility's avoided cost in order to achieve a balance between the interests of ratepayers and PURPA generators, so that the price would be both "just and reasonable to the electric consumers of the electric utility and in the public interest" and "not discriminate against qualifying cogenerators or qualifying small power producers" in comparison to the utility's other supply options. The FERC and the courts have found that a price set at 100% of the utility's avoided cost satisfies this dual standard and the intent of PURPA to encourage QF development.[2] In essence, the economic design of PURPA was to simulate the outcome of a free

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[1] *Section 210(d) of PURPA (92 Stat. 3117, 16 U.S.C. § 2601).*
[2] *18 C.F.R. § 292.304(b)(2);* American Paper Inst., Inc. v. American Elec. Power Serv. Corp., *103 S. Ct. 1921 (1983).*

and open market that would encourage QF development, if QFs could offer generation at a competitive cost equal to or less than the incremental cost to the utility of procuring power from other sources. PURPA generation purchased at the avoided cost price would be reasonable for the consumer because it would be no more expensive than if the monopoly utility had generated the power itself or purchased it from another source.

Q: PURPA was enacted almost four decades ago. Have Congress and the FERC enacted significant changes to PURPA since then?

A: Yes. PURPA was the key first step in the development of independent power generation in the U.S. The success of this new industry in many states under the PURPA framework enabled the creation, in the 1990s and early 2000s, of viable and less-regulated markets for electric generation in many regions of the U.S. Over time, these markets have expanded to include, in some states, competition in generation at both retail and wholesale levels, as well as non-discriminatory access to electric transmission through regional transmission organizations (RTOs) with independent system operators of the transmission grid. In addition, many states have enacted renewable portfolio standard (RPS) programs, based on states' traditional authority over utility procurement, designed to provide long-term markets for the new renewable generation that previously had been developed principally through PURPA. Responding to these developments, Congress enacted the Energy Policy Act of 2005 (EPAct), which implemented a new Section 210(m) of PURPA. This section allowed a utility to petition the FERC for relief from the "must purchase" requirement of PURPA if FERC found that QFs in that utility's territory have access to sufficiently competitive wholesale markets for long-term sales of capacity and electric energy.

Q: Have utilities in other states and regions successfully petitioned the FERC under Section 210(m) of PURPA to end the PURPA must-purchase obligation?

A: Yes. However, this has occurred in states that have opened their generation market to substantial competition at the wholesale level. For example, when the major California investor-owned utilities (IOUs) successfully petitioned the FERC for relief from the PURPA must-purchase obligation for QFs larger than 20 MW, they were able to show that California had taken the following steps to provide viable long-term wholesale markets for QF generation:

- A CPUC-approved program for the IOUs to conduct competitive solicitations for long-term contracts with at least 3,000 MW of existing or new cogeneration QFs;
- A state-enacted RPS that required the California IOUs to purchase 20% (now 33%) of their generation from RPS-eligible renewable generators by 2020, implemented through regular competitive solicitations to procure RPS generation under long-term contracts of up to 25 years;
- A resource adequacy program requiring the IOUs to purchase capacity from QFs and merchant generators to meet near-term resource adequacy requirements; and
- Non-discriminatory access to the transmission system and to an auction-based, day-ahead wholesale energy market operated by a FERC-regulated RTO, the California Independent System Operator (CAISO).[3]

It is important to note that the PURPA must-purchase obligation remains in place in California (and in most other RTO/ISO footprints) for QFs up to 20 MW in size, and that the must-

[3] *Pacific Gas & Electric et al,* 135 FERC ¶ 61,234 (issued June 16, 2011).

purchase obligation can be re-instated if the FERC finds that long-term wholesale markets are no longer available to QFs.

Q: Idaho Power's Petition, at page 33, asserts that the RTOs in which the PURPA must-purchase obligation has ended do not provide markets for wholesale sales longer than three years, citing the testimony of William H. Hieronymous from Case No. GNR-E-11-03, which is attached to Idaho Power's Petition. Do you agree with this argument?

A: No. The flaw in this argument is that the key feature necessary to end the PURPA must-purchase obligation is that renewable and cogeneration resources must have access to long-term power purchase agreements. These new long-term markets are based on procurement programs, principally RPS programs, sponsored by the states under their authority over utility procurement, not through the RTOs. Again, the California RPS program noted above is an example of such a state-sponsored RPS program that provides long-term contracting opportunities for renewable QFs in California. 29 states have RPS programs, and an additional 8 states have less stringent renewable portfolio goals; these 37 states include virtually all of the states whose utilities operate within RTOs and have deregulated wholesale markets.[4]

Q: Has the state of Idaho or electric utilities serving Idaho taken steps that might allow it to petition for relief from the PURPA must-purchase requirements.

A: I am not aware of any such steps that have been taken in Idaho; instead, in this docket the utilities are asking the Commission to make changes that would clearly frustrate the intent of the state's PURPA program. The Petition and Ms. Grow's testimony both mention the possibility of petitioning FERC for relief from the must-purchase obligation under Section 210(m), as well as a

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[4] *See* www.dsireuse.org website data on RPS programs.

range of other changes to Idaho's PURPA program modeled on changes that have been made in California and Texas.[5] However, Idaho Power is not suggesting the pursuit of any of those options at this time.[6]

In my judgement, most of these steps to substantially change the PURPA program in Idaho would require the state to adopt a successor program, such as an RPS, to provide a viable long-term wholesale market for QF generation, and also could require broader changes in the wholesale markets in Idaho and perhaps in the region. Furthermore, even if some of these changes to PURPA were judged to be desirable – for example, even if Idaho enacted an RPS in order to provide more predictable, state-regulated development of renewable resources in Idaho – the competitive market conditions necessary for their approval by the FERC do not yet exist in Idaho. As a result, the longstanding PURPA framework, including the must purchase requirement, will be a feature of the energy landscape in Idaho for the foreseeable future.

III. THE TERM OF PURPA CONTRACTS

Q: What is your recommendation on the utilities' proposal to reduce from 20 years to two years the maximum term for prospective PURPA contracts for QF projects whose size exceeds the cap for eligibility for the published PURPA rate?

A: The proposed reduction in the maximum term for these QF contracts should be rejected, for the reasons presented below.

[5] *Petition*, at pp. 4-5: *Grow Testimony*, at pp. 14-15.
[6] *Petition*, at p. 5: *Grow Testimony*, at pp. 15-16.

Q: What is the first reason why Idaho utilities should continue to make a 20-year contract available to QFs?

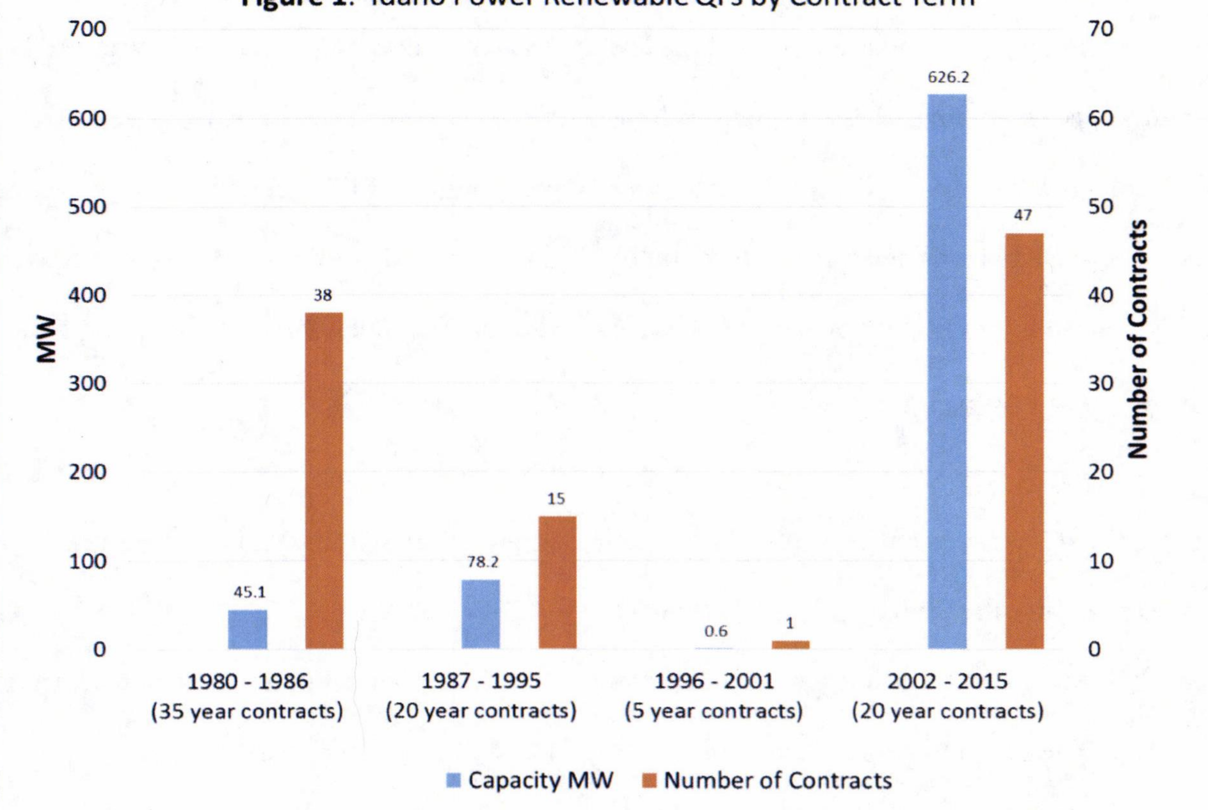
A: As ICL Witness Adam Wenner explains, and I agree, a contract term of this length is necessary to realize PURPA's policy goal of supporting QF development. I also fully agree with Idaho Power's statement on page 8 of the Petition that "the maximum contractual term for a mandatory purchase under PURPA is an extremely important term and condition of the contract and sale." In fact, it is decisive – in my experience, states have successfully encouraged the development of QFs when they have offered long-term (15-year to 35-year) contracts at known avoided cost prices. In contrast, when only short-term (5 years or less) contracts have been available, very few QFs are developed. As I will discuss below, the history of QF development in Idaho and other states supports this conclusion. Developers of solar projects and other renewable QFs will not be able to obtain financing for their projects if all that they can show the lender is that they have a customer for the power for just the first two years of a 25-year project life. In addition, the current indicative pricing for levelized avoided costs for a two-year solar contract are about $29 per MWh, more than 50% below the $60 to $64 per MWh range of avoided costs for the recently-approved 20-year solar contracts.[7] As a result, removing the availability of a long-term contract at avoided cost prices appears likely to make uneconomic QFs that could be developed at avoided cost prices with a long-term agreement. Without an RPS or other state-sponsored procurement program for renewable QFs, it becomes questionable whether Idaho Power's proposed two-year maximum term for PURPA contracts adequately supports QF development in its service territory, as PURPA requires.

[7] Based on data in Idaho Power Response to J.R. Simplot Production Request Question No. 3.

Q: The Petition and the testimonies of Idaho Power's witnesses Ms. Grow and Mr. Allphin present information on the long history of the development of PURPA projects in Idaho. What do you observe about this history?

A: Virtually all of the QF projects successfully developed in Idaho have done so under power purchase contracts with terms of at least 20 years. This includes the small hydro projects developed in the 1980s and 1990s, the wind projects developed in 2010-2012, and the 461 MW of solar projects that the Commission approved in 2014-2015. **Figure** 1 illustrates this history, showing the number and capacity of the QFs that have been successfully developed as a function of the available term of QF contracts.

Figure 1: Idaho Power Renewable QFs by Contract Term



The history shown in Figure 1 is not surprising – renewable energy projects have no fuel costs (except for biomass) but are capital-intensive, and, in my decades of experience I have observed that long-term contracts are essential to access financing on reasonable terms. This need for long-term assurance of capital recovery is the same for QFs as it is for a utility that proposes to build a new power plant and seeks Commission approval for long-term recovery of the plant's costs by including them in rate base. This history suggests that, without long-term, 20-year contracts, QFs will not be developed in Idaho.

Q: What other states provide similar histories?

A: California offered 20- to 30-year PURPA contracts in the 1980s, with renewable QFs provided fixed energy and capacity prices for up to the initial ten years of the contract. About 5,000 MW of renewable QF generation was developed in the state in the late 1980s; most of this capacity is still operating today and now is the lowest cost generation available to the state's RPS program. This development ceased when the long-term contracts were suspended in the late 1980s, and did not revive until after the enactment of the California RPS program in 2004, which again made available long-term contracts of up to 25 years. As another example, the recent active development of solar QFs in North Carolina is founded upon the availability of 15-year contracts at known, fixed prices.

Q: Can you cite a recent example where another state commission has dealt with utility requests to reduce the term of PURPA contracts?

A: Yes. Recently, the utilities in North Carolina asked the commission in that state to shorten the term of PURPA contracts to a maximum of 10 years, a reduction of 5 years from the maximum of 15-year term that in recent years has resulted in significant development of solar QFs in that state. The North Carolina Utilities Commission rejected this request, finding that the term of QF contracts should be long enough to enable QF projects to be financed:

> While the Commission initiated this docket to investigate the need to alter avoided costs determinations, the evidence presented by the buyers and sellers of QF power fail to justify altering the Commission's earlier decisions on term length and related provisions. As discussed earlier, a QF's legal right to long-term fixed rates under Section 210 of PURPA is well established as a result of the FERC's *J.D. Wind* Orders. The FERC has made clear that its intention in Order No. 69 was to enable a QF to establish a fixed contract price for its energy and capacity at the outset of its obligation because fixed prices were necessary for an investor to be able to estimate with reasonable certainty the expected return on a potential investment, and therefore its financial feasibility, before beginning the construction of a facility. In her responses to cross-examination questions about various Duke Energy Renewables projects, DEC/DEP witness Bowman acknowledged the foregoing by stating that PURPA does not require the best financing, just the ability to secure it.[8]

The circumstances that North Carolina faced – with the utilities strenuously claiming to be overwhelmed by solar QF development – are very similar to those in Idaho today, so this decision is directly relevant to this case.

Q: Idaho Power's testimony highlights that it is allegedly not allowed to consider "NEED" in acquiring PURPA resources.[9] Instead of the draconian step of shortening the term of QF contracts, what other steps could Idaho take in order to allow the state greater control over its acquisition of renewable resources?

[8] North Carolina Utilities Commission, *Order Setting Avoided Cost Input Parameters* (Docket No. E-100 Sub-140, issued December 31, 2014), at pp. 19-20. Hereafter, "*North Carolina Avoided Cost Order*".
[9] *Petition*, at p. 27.

A: The Idaho Legislature could enable the state to exert more control of renewable development by enacting an RPS for Idaho. This would allow Idaho utilities to show the FERC that the state has created a long-term wholesale market for additional renewable generation to serve consumers in the state. This showing would be important if the state's utilities were to petition the FERC for relief from the PURPA must-take requirement under Section 210(m), as it was for the California utilities. More generally, an RPS would provide an outlet for renewable development that is under direct state control by the Legislature and the Commission. In states that have RPS programs, when the RPS goal in reached, renewable developers and proponents need to ask the state legislature or regulatory commission to increase the program target. For example, this has already occurred several times in California, as successive RPS goals have been reached.[10] Control over renewable development largely passes to the state, and away from the federal PURPA requirements. Although a state RPS does not automatically allow a utility in that state to avoid the PURPA must-purchase obligation, it would make it more difficult for a would-be QF to assert to the FERC that the utility has not done enough to promote QF development, if the utility was in compliance with the state's RPS program. Further, as noted above, an RPS can be an integral part of a showing under Section 201(m) to end the must-purchase obligation.

Finally, an RPS would allow Idaho consumers to benefit directly from the extensive renewable development that has already occurred in the state, and that could continue in the future. Because Idaho has no RPS, and because Idaho Power either does not acquire or sells the

[10] California's initial RPS goal, enacted in 2004, had a goal of 20% renewable generation by 2017. This goal was later advanced to 20% by 2010, and then increased to the current 33% by 2020. Legislation has been introduced this year for a further increase to 50% by 2030. California's investor-owned utilities acquire RPS resources through regular competitive solicitations in which new renewables are procured under the dual standards of (1) least-cost and (2) best-fit to the needs of the utility. Each utility's need for RPS generation is subject to an extensive planning process overseen by the California Commission, similar to Idaho's IRP process.

renewable energy credits (RECs) associated with the renewable resources that it purchases, Idaho Power cannot and does not claim that it serves its customers with this renewable generation.[11] The utility's Petition compares the amount of renewables on its system to the RPS requirements in other western states that have RPS programs, but these comparisons are meaningless because the RECs associated with this generation are not retired. As a result, renewable development in Idaho supports the RPS programs in other states but does not provide new, clean generation to Idahoans or add to the amount of renewable generation in the region as a whole.

IV. THE COMMISSION'S IRP METHOD IS WORKING WELL

Q: Do you agree with the Commission's conclusions in its recent orders approving solar contracts that the IRP method of setting avoided cost prices for these contracts is working well?

A: Generally, yes. The IRP method allows the fuel price and load forecasts used in calculating avoided cost prices to be updated every year. The Company also is able to include previously-approved QF contracts in these updates.[12] The result of such updates is that the price in solar contracts has declined as fuel and load updates have occurred and as additional contracts have been added, as shown in **Table 3**. The table reflects that the initial solar contracts used a July 2013 capacity sufficiency year,[13] while in the contracts submitted in October 2014, the date of sufficiency had been pushed out to July 2021.[14]

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[11] The utility's Application and testimony discusses at length the substantial renewable development that has occurred in Idaho under PURPA, but the utility carefully footnotes its text and figures with the revealing disclaimer that "Idaho Power cannot represent to customers that they are receiving renewable energy from the QFs." See *Allphin Testimony*, at p. 8, footnote 1; also, *Petition*, footnote to the figure on p. 11.

[12] *See Order No. 32697* at p. 22.

[13] *See Order No. 33016.*

[14] *See Order No. 33159.*

Table 3: *Idaho Power Solar Contract Prices* [15]

Contract	Date Application Submitted	20-year Price ($/MWh)
Approved Contracts		
Grand View PV Solar Two	7/25/2014	73.41
Boise City Solar	7/25/2014	72.15
Simco Solar	10/20/2014	63.94
Murphy Flat Power	10/20/2014	63.80
American Falls Solar	10/20/2014	63.61
American Falls Solar II	10/20/2014	62.66
Orchard Ranch Solar	10/20/2014	62.21
Mountain Home Solar	10/17/2014	61.43
Pocatello Solar 1	10/17/2014	61.33
Clark Solar 2	10/17/2014	61.03
Clark Solar 4	10/17/2014	60.87
Clark Solar 3	10/17/2014	60.67
Clark Solar 1	10/17/2014	59.97
Potential Contracts		
Project A1		52.83
Project A2		54.10

The even lower indicative prices for the potential solar contracts A1 and A2 indicates that Idaho Power may be using a capacity sufficiency date that is even further in the future. It is my

[15] Data on approved contracts are from Idaho Power Response to Idaho Irrigation Pumpers Association Production Request No. 11. Data on the potential contracts are from Idaho Power Response to Staff Production Request No. 9.

understanding that the IRP methodology prices will be further revised when Idaho Power files its 2015 IRP on June 30, 2015. Given that indicative solar contract prices are approaching $50 per MWh, which is at the low end of solar PPA prices as reported by the Lawrence Berkeley National Lab (LBNL),[16] it is not clear to me that all of the 885 MW of projects will be able to be developed successfully at these prices. In fact, I reviewed Idaho Power's response to Simplot discovery Question 4 and observe that, of the 885 MW of possible solar projects, consisting of 48 projects, the Company can cite only 14 projects that have progressed far enough to receive indicative prices and only 1 project that has a draft sales agreement.

In my judgement, the Commission should be pleased that the IRP method is working as intended. As more solar capacity has been added, the avoided cost price has fallen based on Idaho Power's capacity position and future need. It is simply not true that the Commission's avoided cost methodology fails to consider the future need for new capacity – as the need for capacity is pushed further out into the future, the avoided cost price falls. It is basic economic principle that, as prices fall, fewer projects will be built. And it is also true that if additional solar can be developed at the new, lower prices that reflect the utility's current need, then Idaho's consumers will benefit from additional renewable generation at even lower costs. As I will discuss in detail below, there are many benefits of this new renewable generation that are not included in the avoided cost price. The Commission should reject Idaho Power's proposal to turn its back on these benefits by reducing the term of these PURPA contracts, a step that essentially would relieve the utility from its PURPA obligations. I share the perspective of Commission staff that was cited in Order 32697:

[16] Bolinger, Mark and Weaver, Samantha, *Utility-scale Solar 2013: an Empirical Estimate of Project Cost, Performance, and Pricing Trends in the U.S* at pp. 26-31 and Figure 16, (LBNL, September 2014) (Hereafter "LBNL Solar Cost Report").

"[t]he proper mechanism for accounting for utility need is not to relieve utilities of their obligation to purchase, but instead to establish prices for capacity and energy that properly recognize the utilities' need, or lack of need, for capacity and energy."[17]

V. RATEPAYER BENEFITS FROM FIXED-PRICE PURPA GENERATION

Q: Idaho Power alleges that the continued availability of long-term contracts "inflates the power supply costs borne by customers."[18] Do you agree with this contention?

A: No. Not only does Idaho's IRP methodology produce reasonable avoided costs that reflect the utilities' needs, as I will explain below, Idaho Power's customers will realize significant additional net benefits from the utility's purchase of renewable generation under PURPA – benefits that are not included in the avoided cost price. These include:

1. REC sales revenues, or avoided costs for reducing carbon emissions
2. Hedging benefits
3. Market price mitigation benefits
4. Capacity optionality
5. Local economic benefits

Further, Idaho Power's assertions that QF generation will displace less expensive generation are simply not credible.

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[17] *Order No. 32697* at p. 19, citing Tr. at 1090.
[18] *Petition,* at p. 21, also, generally, pp. 20-25.

Generally, it is important to remember that the prices in these contracts are set based on the best available estimate of the utility's avoided costs, that is, the costs which the utility would incur if it did not buy from the QF, but instead generated the power itself or purchased it from another source. Assuming that these estimates are as accurate as possible (which we will discuss below), then by definition these contracts will not have an adverse impact on Idaho Power's customers, because the utility's costs will be no different than if they had not purchased this generation. Idaho Power's Petition and testimony present numerous figures and tables showing how the utility's PURPA expenses are increasing significantly and would be even higher with the 885 MW of proposed solar contracts.[19] This data is irrelevant assuming that the proposed contracts are priced at the utility's avoided costs, because the increased PURPA expenses will be offset by corresponding reductions in Idaho Power's costs for the other resources that the new PURPA generation will replace. Customers will be at least indifferent to the purchase of the PURPA generation, which is the basic tenet of PURPA.

Q: Please respond to Idaho Power's assertion that this additional PURPA generation will displace less expensive generation, such that "the Company's overall net power supply expense, on a dollars per MWh basis, would increase, adversely impacting customers."[20]

A: Significantly, when asked for the impact of these PURPA contracts on future retail electric rates, the utility conceded that it had not done that analysis.[21]

Further, the utility's allegation of adverse ratepayer impacts is not true, because the utility is making apples-to-oranges comparisons among its generation costs. The cost of PURPA

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[19] *Petition,* at pp. 22-23; *Allphin Testimony,* Exhibit No. 7.
[20] *Petition,* at pp. 23-25.
[21] Idaho Power Response to Staff Production Request No. 2, included in Exhibit IPC/SC-302.

generation is an all-in, long-term cost that includes both the energy and capacity provided by this generation. Moreover, the QF power is delivered to Idaho Power within its service territory, without incurring the cost of transmission from out-of-state locations or regional markets. For example, the Company compares its PURPA generation costs to Mid-Columbia (Mid-C) market prices.[22] The Mid-C prices do not include the costs of the transmission capacity (including, in the future, Boardman-to-Hemingway) necessary to deliver Mid-C power to Idaho. In addition, the comparison to general Mid-C prices does not consider that, in some peak hours, this power is not deliverable to Idaho due to transmission constraints; in these hours, PURPA generation can displace internal Idaho Power gas-fired peaking resources that are more expensive than Mid-C prices.

Similar problems exist with the comparisons to the Company's coal, natural gas, and non-PURPA purchased power expenses.[23] In response to ICL's discovery, Idaho Power responded they provided only the fuel costs for coal and gas.[24] Idaho Power's comparison between PURPA prices and coal costs do not include the incremental capital or O&M expenses associated with the utility's coal generation, or with the transmission costs to move this power into Idaho. Likewise, the natural gas expenses do not include the incremental capital, natural gas pipeline reservation costs, or O&M expenses associated with the utility's gas generation. Moreover, the PURPA contract costs for the solar contracts will be fixed for the 20-year contract term, while the variable costs of coal, gas, and other purchased power will increase significantly over the next 20 years. When costs are compared on an apples-to-apples basis and measured over the full expected life of these contracts, the PURPA generation is no more expensive than the

[22] *Petition,* at pp. 23-24; also *Allphin Testimony,* Exhibit 10.
[23] *Petition,* at p. 24; also *Allphin Testimony*, Exhibit 8.
[24] Idaho Power Response to ICL Production Request No 5, included in Exhibit IPC/SC-302.

marginal or avoided cost of the generation that it will displace, as required by the Commission's IRP method of setting avoided cost prices. In fact, for the reasons discussed below, the solar contracts will offer benefits that will result in lower power supply costs for Idaho Power's customers.

i. REC revenues / avoided carbon mitigation costs

Q: What other benefits do Idaho Power's customers realize from PURPA generation?

A: In the absence of an RPS, Idaho Power sells the renewable energy credits (RECs) associated with the renewable resources that it purchases, and the revenues from these sales are a benefit for ratepayers. Pursuant to Commission Order No. 32697, QFs who sign long-term contracts with pricing under the IRP method must supply 50% of the associated RECs to Idaho Power. And it is my understanding that Idaho Power sells any RECs the Company holds and returns to revenue to customers. If the Commission reduces the maximum contract length so that future QFs have no opportunity to access project financing, then it is my understanding Idaho consumers would not enjoy additional revenue from future QFs.

Q: Does Idaho Power receive significant revenue from these REC sales that benefit its ratepayers?

A: Yes. These revenues for 2010-2014 are shown in the following table:

Table 1: *Idaho Power REC Sales*

Year	REC Sales *(MWh)*	Revenues *($ M)*	REC Price *($/MWh)*

2010	808,862	4,485,724	$5.55
2011	596,225	6,517,833	$10.93
2012	445,687	3,592,782	$8.06
2013	251,774	564,378	$2.24
2014	598,736	3,218,529	$5.38
Average	540,257	3,675,849	$6.80

I expect that the purchasers of these RECs use them to meet RPS compliance obligations in neighboring states in the West. All of the other states in the WECC have RPS programs or goals, except for Wyoming.

It is my understanding that 95% of the Idaho-jurisdictional revenues from these REC sales is returned to consumers in Idaho. Based on this track record, the 885 MW of additional solar contracts could add $7.8 million per year in additional REC revenues to the benefit of Idaho Power customers.

Q: Will Idaho Power benefit if it retains the RECs associated with this generation?

A: Yes. If the RECs are retained and retired, then Idaho Power can claim a share of the carbon emission reductions associated with this power. Assuming that the 885 MW of potential solar contracts displace gas-fired generation at a heat rate of 8.0 MMBtu per MWh, and using the carbon emission costs that Idaho Power assumed in its last IRP ($14.64 per ton in 2018, escalating at 3% per year), the value of Idaho Power's 50% share of these reductions in carbon emissions is about $7.2 million per year over the life of these resources, or about $4 per MWh.[25] In the High Carbon case in the IRP ($35 per ton in 2018, escalating at 9% per year), the value of these carbon reductions is $28 million per year or $15 per MWh. I am not aware of what steps Idaho Power may take to comply with the proposed federal carbon emission regulations under Section 111(d) of the Clean Air Act, but these benefits can be considered a proxy for the future compliance costs that the utility may avoid by increasing its purchases of renewable generation.

ii. Hedging benefits

Q: Idaho Power argues that "at a time of unprecedented changes in the technological, economic, and regulatory landscapes faced by the electric industry today," it is risky for consumers to commit to long-term fixed-price contracts. Do you agree?

A: No. Based on my 35 years' experience in the energy industry in the western U.S., the "landscape" has always been changing, and it is difficult to tell whether the changes on the horizon today are more unprecedented than they have been in the past. With any fixed-price power purchase contract – and with any significant capital investment by the utility in generation or transmission – there is always a risk that the alternatives will prove to be less expensive over the long-term. This is a risk that consumers bear with PURPA contracts, with other purchases in wholesale markets, and with the alternative of utility-owned fossil-fuel plants whose capital costs are largely fixed once they are approved for cost recovery through rate base and whose fuel costs are subject to significant market risk. Idaho Power complains that the prices or terms of QF contracts cannot be modified once they are signed, yet it is also difficult to modify the costs for

[25] To be fair, any new sources of renewable or low-variable-cost generation will produce such benefits, including Idaho Power's hydro repowering mentioned in the Application.

utility owned generation included in the rate base once they have been authorized. If it is too uncertain and too risky to forecast avoided cost prices for 20 years, then it is also too risky to evaluate the merits of a new utility-owned resource (such as the planned Boardman-to-Hemingway transmission line), or even to make decisions based on the long-term projections in an Integrated Resource Plan.

The North Carolina commission recognized this in its recent avoided cost order, concluding that the uncertainties in future energy markets will impact ratepayers regardless of whether the utility contracts with QFs at avoided cost or builds its own resources:

> Failure to calculate accurately a utility's avoided cost means ratepayers will pay for the additional energy and capacity whether the utility builds the plant and places it in rate base or the utility pays QFs avoided cost rates. The Commission concludes that establishing avoided cost rates based upon the best information available at the time and making such rates available in long-term fixed contracts, as required by Section 201 of PURPA should leave the utilities' ratepayers financially indifferent between purchases of QF power versus the construction and rate basing of utility-built resources.[26]

Q: Do fixed-price contracts for renewable generation provide a benefit to consumers as a hedge against future uncertainty and volatility in energy and fossil fuel markets?

A: Yes. The alternative to the PURPA contracts is reliance on marginal utility fossil generation (mostly natural gas-fired) and/or market purchases, whose prices also are influenced heavily by gas prices. The value for ratepayers of hedging this exposure is simple: fixed-price

[26] *Supra* n. 8, *North Carolina Avoided Cost Order*, at p. 21.

generation protects against periodic spikes in natural gas prices. Such spikes have occurred regularly over the last several decades, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 2** below.[27]

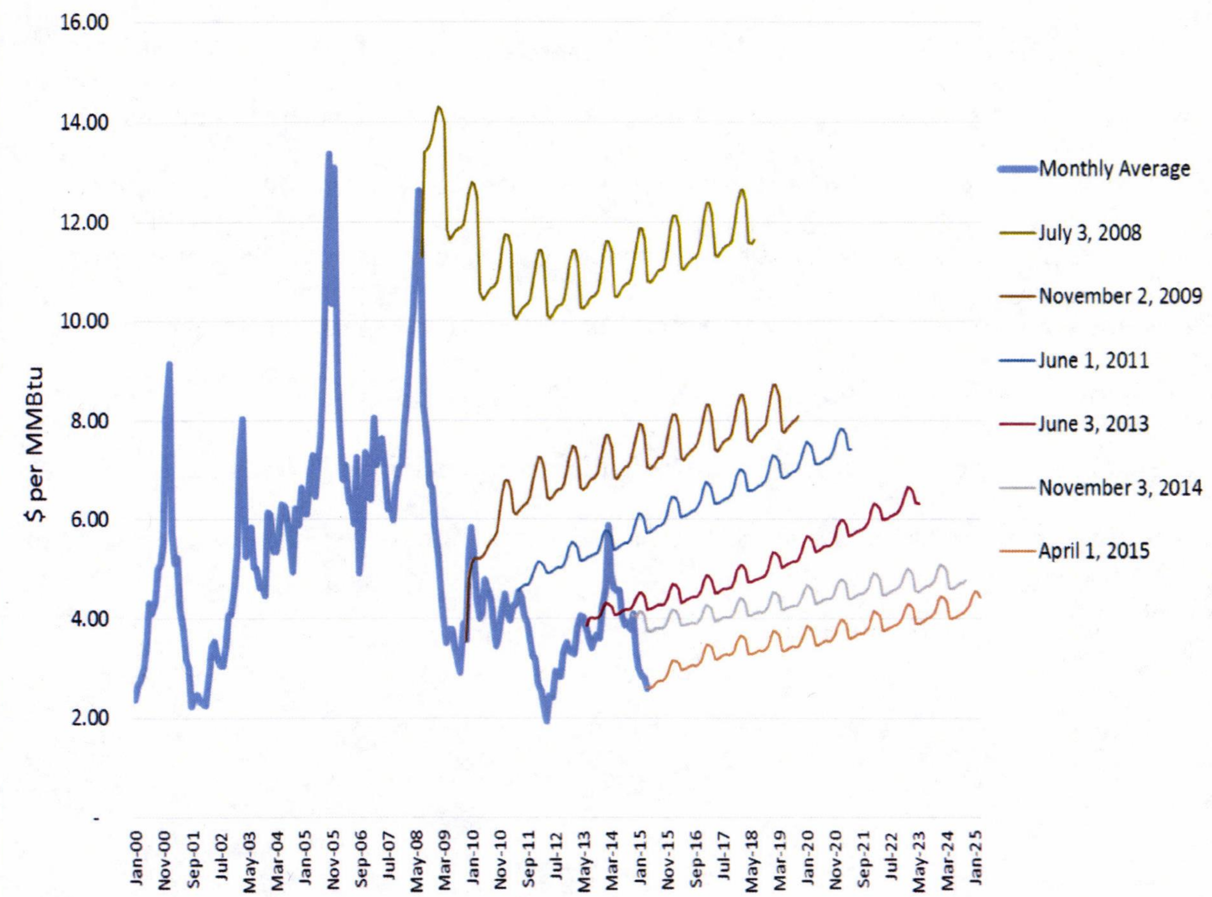

Figure 1: Henry Hub Market Prices
Monthly Average and Selected 10-Year Forward Market Prices

Fixed prices also hedge against market dislocations or generation scarcity such as was experienced throughout the West during the California energy crisis of 2000-2001 or as is occurring today with the extreme drought in California and long-term, drier-than-normal conditions elsewhere in the West. In 2014, the rapidly increasing output of solar projects in California made up for

[27] Figure 2 based on Chicago Mercantile Exchange data.

83% of the reduction in hydroelectric output in the state due to the multi-year drought.[28] Obviously, there is a risk that consumers may not benefit if future prices turn out to be lower than anticipated, but, if that happens, there is the compensation that consumers will enjoy the low prices for the portion of their needs that is not hedged. Despite this risk, hedging in a commonly accepted practice in utility operations and regulation.

The economic literature generally finds that the fixed-price, zero-fuel-cost nature of renewable generation provides a positive value as a hedge against future increases in fossil fuel prices. For example, in a recent study the Lawrence Berkeley National Lab (LBNL) compared fixed-price, long-term wind contracts to the range of expected prices for gas-fired generation, based on the range of recent Energy Information Administration (EIA) gas cost forecasts.[29] LBNL concluded that current wind PPA prices in the range of $50 per MWh offer significant benefit as a hedge against the expected range of future fossil fuel prices, even in today's low-price environment for natural gas as a result of the shale gas revolution. Here is the key figure from the LBNL study:

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[28] Based on Energy Information Administration data for 2014, as reported in Stephen Lacey, *As California Loses Hydro Resources to Drought, Large-Scale Solar Fills in the Gap: New solar generation made up for four-fifths of California's lost hydro production in 2014* (Greentech Media, March 31, 2015). Available at http://www.greentechmedia.com/articles/read/solar-becomes-the-second-biggest-renewable-energy-provider-in-california.

[29] Bolinger, Mark, *Revisiting the Long-term Hedge Value of Wind Power in an Era of Low Natural Gas Prices*, LBNL-6103E, (March 2013). Available at http://emp.lbl.gov/sites/all/files/lbnl-6103e.pdf

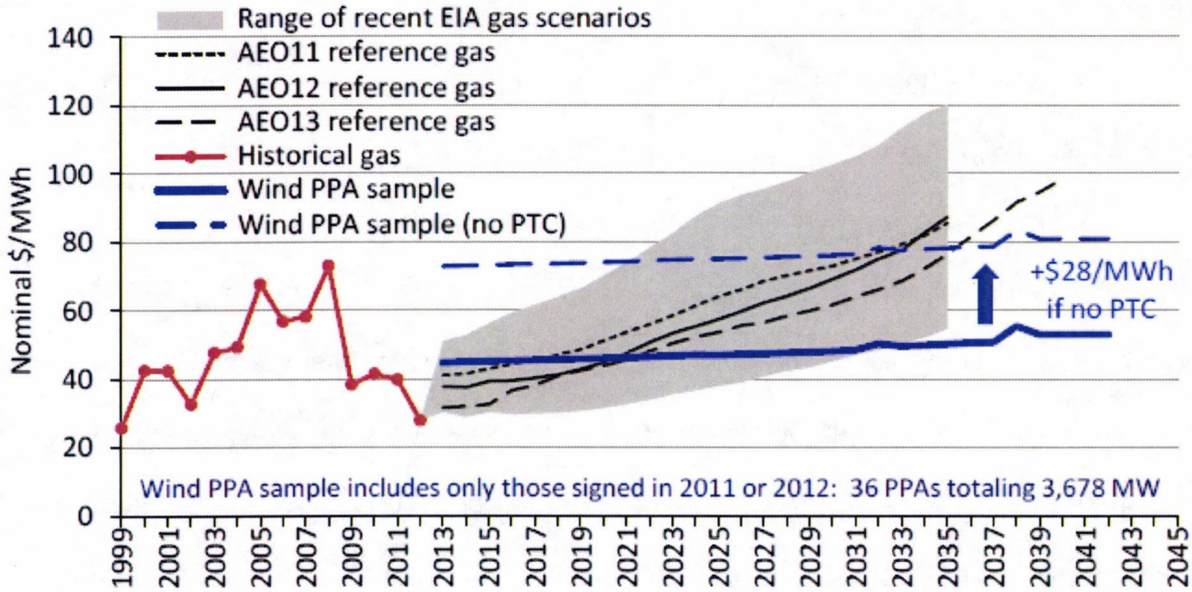

Figure 9. Comparison of Recent Wind PPA Sub-Sample to Projected Range of Natural Gas Prices

A number of studies have quantified these hedging benefits. In the West, Public Service of Colorado has estimated that the long-term (20-year) hedging benefits of distributed solar resources on its system are $6.60 per MWh.[30]

In light of this well established economic theory backed up by empirical studies, it is remarkable that Idaho Power, when asked in discovery whether "long-term, locked-in price estimates [in PPAs] could potentially benefit Idaho Power in some circumstances," the utility's response was a flat "no."[31]

iii. Market Price Mitigation

[30] Xcel Energy Services, *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System: Study Report in Response to Colorado Public Utilities Commission Decision No. C09-1223* (May 2013), at pp. 6 and 43, and Table 1. This study used the cost of options contracts in the gas futures market to calculate the hedging benefit. Similar methods have been used in many other solar valuation studies in other regions of the U.S.

[31] Idaho Power response to Staff Production Request 18, included in Exhibit IPC/SC-302.

Q: Will an increasing penetration of new renewable generation in Idaho and the West have an impact on energy market prices?

A: Yes. This new solar generation will increase the electricity supplies available to Idaho Power. Because this generation is must-take (and has zero variable costs), it will displace the most expensive fossil-fired or market resources that Idaho Power would otherwise have generated or purchased. The addition of this local generation will reduce the demand which Idaho Power places on the regional markets for electricity and natural gas. With this reduction in demand, there is a corresponding reduction in the price in these markets, which benefits Idaho Power when it does buy power or natural gas in these markets. This "market price mitigation" benefit of renewable generation is widely acknowledged, and has become highly visible in markets that now have high penetrations of wind and solar resources. The magnitude of these benefits will depend on the overall amount of renewables on the western grid.

Q: Are you aware of any modeling of this benefit in the West?

A: Yes. The National Renewable Energy Laboratory (NREL) and GE Consulting have undertaken the Western Wind and Solar Integration Study (WWSIS), a major, multi-phase modeling effort to analyze much higher penetrations of wind and solar resources in the western U.S.[32] Although this work focused on the West Connect area (basically, Arizona, Colorado, New Mexico, Nevada, and Wyoming), the modeling has included the entire WECC grid in the U.S., including Idaho. For example, the WWSIS study of high penetrations of solar (25% penetration in West Connect) also included 15% solar penetration in nearby states, including 1,000 MW of

[32] The high penetration solar results from the WWSIS are reported in NREL and GE Consulting, *Impact of High Solar Penetration in the Western Interconnection*, at p. 8 and Figure 19 (December 2010). This report, as well as all reports from the WWSIS, are available on the NREL website at: http://www.nrel.gov/electricity/transmission/western_wind.html.

solar in Idaho. This modeling included analysis of the impact of increasing solar penetration on market prices in the West; the results for spot prices in Arizona are shown in the figure below. Generally, the high penetration solar cases (15% to 25% penetration) result in 10% to 20% reductions in spot market prices. Note that the largest reductions in market prices from a 5% increase in penetration occurs at the low penetrations of solar, which is where the West is today. Only in California is on-line solar penetration approaching even 5% today.

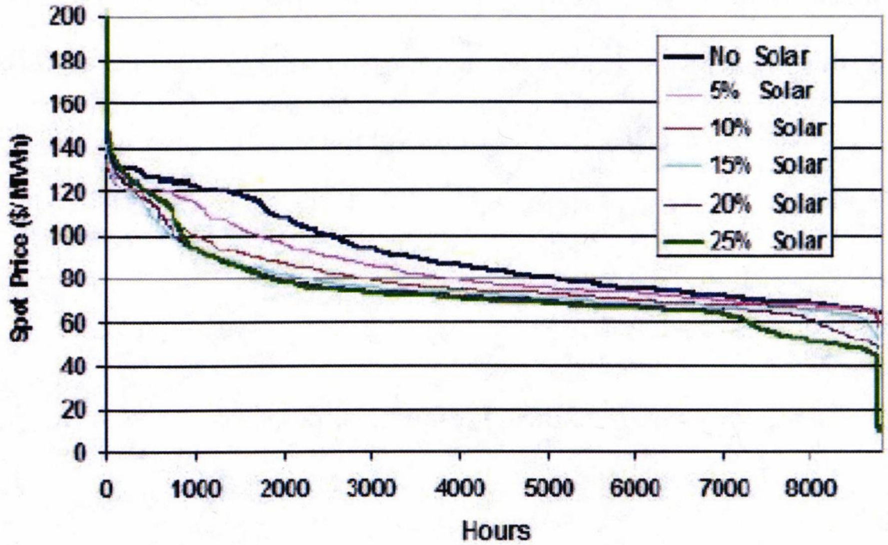

Figure 19 – Arizona Spot Price Duration Curves.

The same market mitigation benefits exist on the natural gas side. Renewable generation reduces marginal gas-fired generation, thus lowering the demand for natural gas. A study by LBNL has estimated that the gas-related market mitigation benefits of renewable energy range from $7.50 to $20 per MWh of renewable output.[33]

[33] *See* Wiser, Ryan; Bolinger, Mark; and St. Clair, Matt, *Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency,* at ix (January 2005), Available at: http://eetd.lbl.gov/sites/all/files/publications/report-lbnl-56756.pdf

As context for how these market price reductions might benefit Idaho consumers, the utility's net electric market purchase expenses in 2015-2016 are forecasted to be $9.3 million; its natural gas expenses are anticipated to be $57.2 million.[34]

Q: Are the fuel hedging and market price mitigation benefits that you have calculated related?

A: They are related in that both involve energy market prices for electricity and natural gas. The fuel hedging benefit for consumers results from a reduction in the volatility of these market prices – in other words, in a reduced risk of periodic price spikes in these commodity markets. The market price mitigation benefit is from an overall reduction in the levels of these market prices. Thus, these benefits are related but do not necessarily overlap.

Q: Will some of Idaho Power's other potential future resource options also realize such benefits?

A: Yes. To be fair, any new sources of renewable or low-variable-cost generation will produce such benefits, including Idaho Power's hydro repowering mentioned in the Petition. However, historically PURPA, and the long-term contract Idaho allows, has been a major source of new generation that provides these benefits.

iv. Capacity optionality

[34] *Direct Testimony of Scott Wright*, IPC 2015-2016 PCA, Case No. IPC-E-15-14, at Tables 1 and 2. Net electric market costs are the sum of Accounts 555 (Purchased Power Non-PURPA) and 447 (Surplus Sales). Gas costs are from Account 547 (Other Fuel).

Q: Will these additional solar resources provide new generating capacity in Idaho Power's service territory?

A: Yes. In developing the 2015 IRP Idaho Power assumes that solar generation will provide annual capacity equal to about 20 – 30%, and peak hour capacity up to 51% of its nameplate capacity.[35] This is based on a very conservative 90% exceedance method. In contrast, other RTOs and control areas in the U.S. use 70% or 50% exceedance methods to assess the capacity value of solar. Thus, the additional 885 MW of solar resources would add at least 280 MW[36] and as much as 440 MW[37] of capacity. All of this capacity would be internal to Idaho Power's system, and will not require additional out-of-state transmission capacity to be deliverable to Idaho Power's customers.

Q: Initial results from Idaho Power's 2015 IRP show the next need for capacity is not until 2025, when the 461 MW of approved solar contracts is included in the resource stack.[38] Is there a potential benefit even if the additional 885 MW of solar capacity comes on-line before it is expected to be needed under the utility's current IRP?

A: Yes. Idaho Power has no immediate need for capacity based on its current IRP, and this lack of need is priced into the solar contracts, both those that the utility has signed recently and those that it might sign in the near future. This assumed lack of need results in lower prices in these contracts. However, events may occur that accelerate Idaho Power's need for capacity. One example is the recent short-term cutback in Idaho Power's demand response programs, which

[35] Idaho Power presentation to the IRP Advisory Committee on October 2, 2014 at page 4. Available at: https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/presentation100214.pdf
[36] The 90% exceedance value.
[37] 50% of nameplate based on the on-peak capacity factor.
[38] Idaho Power presentation to the IRP Advisory Committee on February 5, 2015 at pages 29 - 30. Available at: https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/presentation020515.pdf

resulted in a significant short-term acceleration of date of the utility's first need until the funding for that program was restored.[39] Another possible factor that could accelerate Idaho Power's need is the retirement by 2020 of a portion of the utility's coal capacity, which could occur for a variety of reasons, including the cost of additional emission controls, decisions made by Idaho Power's partners to terminate their involvement in these plants, or compliance needs related to the federal government's Clean Power Plan.

As a result, the possible renewable contracts provide Idaho Power essentially with a free option to replace from 280 MW to 440 MW of existing capacity prior to the current date when capacity otherwise is expected to be needed. In other words, customers in Idaho will gain insurance, at no cost, against events, which might threaten reliability by suddenly accelerating the need for capacity. Based on the capacity costs that appear to be included in Idaho Power's IRP-based indicative prices for the potential solar contracts, the value of this option is $9 million to $14 million per year assuming that the capacity is needed in a year before 2022.

v. Local economic benefits

Q: Will there be economic benefits from Idaho from additional development of the state's indigenous resources?

A: Yes. The construction of an additional 885 MW of solar generation in Idaho will represent an investment of $2.7 billion in Idaho, assuming a capital cost of $3,000 per kW.[40] Not all of this money will be spent in Idaho, of course, but there will be significant short-term

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[39] See *Order No. 33016* at pp. 1-2, and *Order No. 33084* at p. 5.
[40] *Supra n. 16,* LBNL *Solar Cost Report,* at pp. 11-14.

employment benefits during construction as well as permanent employment operating and maintaining these facilities, as well as royalties to landowners and property taxes to local communities. Significantly, these facilities will be located in Idaho, so the economic benefits are more likely to accrue to Idahoans than if these were out-of-state power plants, power purchases from regional markets, or transmission lines that only terminate in Idaho (such as Boardman-to-Hemingway).

vi. A window of opportunity to procure low-cost solar

Q: Idaho Power asserts that the PURPA contracting process generally means that QFs will request long-term contracts at times when forecasts of future avoided cost prices are high. Is this concern present today?

A: No. Natural gas prices today are quite low in historical terms, particularly for longer-term forward contracts. Figure 2, above on page 18 also shows several examples of the 10-year forward price for natural gas at the Henry Hub in recent years. This shows that today's avoided costs are relatively low. New sources of clean energy are competitive with this price. Put simply, if today's independent QF developers can meet or beat this avoided cost, then it will be a good deal for ratepayers.

Q: Is this a good time to contract for new solar generation, in terms of the price for this renewable generation?

A: Absolutely. Idahoans need energy every day and the PURPA contracts supply this energy at or below the utilities' avoided costs. It is critical to recognize that the 30% federal investment tax credit (ITC) expires at the end of 2016, after which it will drop to 10%. As a result, the levelized cost of solar generation is expected to rise significantly for several years beginning in 2017, until cost reductions for this technology can offset the loss of this significant incentive. Using a generation cost tool developed for the WECC, the drop in the federal ITC could add $15 to $20 per MWh (+20% to +25%) to solar contract prices after 2017.[41] As a result, now is an opportune moment to purchase solar generation at contract prices that may not be available for a considerable period after 2016.[42] Based on solar PPA prices surveyed by LBNL through mid-2014, the utility-scale PPA prices at which Idaho Power has procured solar generation (and today has a window of opportunity to procure more) are comparable to the solar PPAs being procured elsewhere in the country, as shown in the figure below.[43]

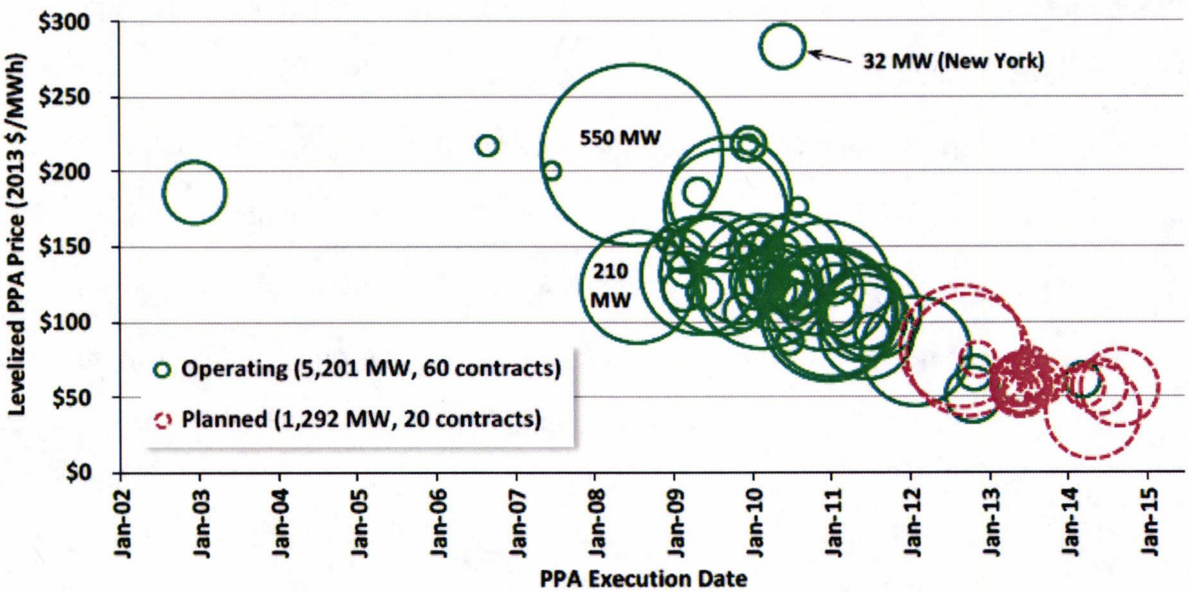

Figure 16. Levelized PPA Prices by Operational Status and PPA Execution Date

[41] Based on the *2012 WECC Generation Costing Tool*, developed by Energy & Environmental Economics for the WECC. Available at https://ethree.com/public_projects/renewable_energy_costing_tool.php, assuming a $2,000 per kW utility-scale solar PV capital cost in 2017.

[42] This is what the California utilities concluded in 2013, even though they had largely contracted adequate generation to reach the state's 33% by 2020 RPS goal. *Supra* n. 28, Lacey, Steven *As California Loses Hydro Resources to Drought, Large-Scale Solar Fills in the Gap.*

[43] *Supra* n. 16, LBNL *Solar Cost Report*, at pp. 26-31 and Figure 16.

VI. SYSTEM RELIABILITY

Q: Idaho Power is concerned that it will not be able to integrate additional intermittent solar generation into its system, and that the new resources will aggravate the oversupply situation that it faces at certain times of the year, principally in the spring months when hydro resources are abundant. Please comment.

A: First, it is my understanding that Idaho Power recently completed a solar integration study and is currently expanding this study to include larger penetrations of solar power.[44] Also, the recent solar QF contracts in Idaho require the QF project to cover these integration costs. Second, Idaho Power could reduce the oversupply issue by 15 – 29% by idling the Valmy coal plant in 2016 and 2017.[45] Third, as I explain below recent studies of the western grid conclude the system can integrate high solar penetrations and that evolving market mechanisms, like the Energy Imbalance Market, can facilitate this integration.

The integration of higher levels of wind and solar resources presents a challenge to utilities and grid operators across the U.S., not just in the West. In recent years, significant effort and numerous studies have been conducted on the operational and system reliability impacts of the increasing penetration of variable renewable resources. The WWSIS is the most significant such effort in the WECC. As noted above, the WWSIS included a high solar penetration study that considered a 25% solar penetration in the West Connect area, and 15% penetration in the rest of the WECC (including 1,000 MW of solar in Idaho). The WWSIS concluded that it will be

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[44] *See* IPC-E-14-18.
[45] Based on data from Idaho Power Response to ICL Production Request No 6.

feasible to operate the WECC grid at these levels of solar penetration in the WECC, provided that certain operational changes are made. The key findings of the WWSIS include:

- Increasing the size of the geographic area over which the wind and solar resources are drawn substantially reduces variability.

- Scheduling generation and interchanges subhourly reduces the need for fast reserves.

- Using wind and solar forecasts in utility operations reduces operating costs by up to 14%.

- Existing transmission capacity can be better used. This will reduce new transmission needs.

- Demand response programs can provide flexibility that enables the electric power system to more easily integrate wind and solar—and may be cheaper than alternatives.

Efforts are already underway to implement such changes. Most notably, PacifiCorp has joined with the CAISO to create a new energy imbalance market (EIM) that is intended, among other benefits, to address the first two findings of the WWSIS – balancing wind and solar resources over a larger geographic footprint and reducing the costs of integrating such resources by balancing the system more efficiently on a sub-hour basis. A white paper from the FERC staff explains the benefit's of an EIM for renewable integration:

> An EIM could enhance the reliability of the bulk power system as the system moves towards higher levels of variable energy resources. Balancing authorities need reserves that are loaded and able to reduce output, as well as reserves that are

unloaded and able to increase output, in order to respond to the variability from variable energy resources. Without an EIM, the variability from variable energy resource output in the Western Interconnection is not diversified across balancing authorities. An EIM could help manage variable energy resources more reliably by pooling variability over a larger area, and redispatching resources to help manage imbalance energy caused by variable energy resources.[46]

The EIM began operations on November 1, 2014, and achieved $6 million in savings for its participants in just the first two months of operation.[47] NV Energy and Puget Sound Energy will be joining the EIM in October 2015 and October 2016, respectively; thus, by the end of 2015, utilities that operate in all of the states that neighbor Idaho will be participating in this market.[48] In discovery, Idaho Power stated that it cannot join the EIM because it lacks the transmission rights to do so (presumably, a lack of rights to access the CAISO balancing area).[49] However, it is my understanding that utilities can participate in the EIM using Available Transmission Capacity even if they do not have rights to the CAISO area[50] and that the EIM will be modifying its protocols to allow expansion to non-contiguous balancing areas within the WECC.[51] Significantly, the costs of participation in the EIM are based largely on how much you use it, and

[46] FERC, *Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market*, at p. 17 (February 26, 2013) Available at: http://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf

[47] CAISO, *Benefits for Participating in EIM*, at slide 3 (February 11, 2015) Available at : http://www.caiso.com/Documents/Presentation-PacifiCorp_ISO_EIMBenefitsReportQ4_2014.pdf

[48] A fact sheet from PacifiCorp about the EIM is Exhibit IPC/SC-303 to this testimony. See also https://pse.com/aboutpse/PseNewsroom/NewsReleases/Pages/PSE-to-Join-Energy-Imbalance-Market.aspx.

[49] Idaho Power response to J.R. Simplot Company Production Request 16, included in Exhibit IPC/SC-302.

[50] For example, NV Energy plans to use Available Transmission Capacity, and not firm transmission rights, for its EIM transfers. See CAISO, *Energy Imbalance Market Year 1 Enhancements - Draft Final Proposal*, at p. 3 (February 11, 2015). Available at: http://www.caiso.com/Documents/DraftFinalProposal_EnergyImbalanceMarketYear1Enhancements.pdf

[51] *Ibid.*, at pp. 19-21.

participants retain dispatch authority within their control areas. In essence, the EIM promotes the more granular and efficient exchange of power among the participating control areas.

Although the WWSIS study showed the ability to integrate 15 – 25% solar penetration, the rest of the West, except for California, is not close to even a 5% level of solar penetration today. Thus, today Idaho Power should be able to integrate the possible level of solar generation on it system, especially if it can obtain greater access to balancing resources in the region through mechanisms such as the EIM. In addition, the 461 MW of approved solar contracts will be sited in or close to Idaho Power's Treasure Valley load center; I assume that the additional 885 MW will be interconnected directly to Idaho Power's system as well. Because these resources will be internal to Idaho Power's system and will produce significant power during the utility's summer on-peak hours, they should reduce loadings on the congested transmission paths into Idaho during these summer peak periods, further increasing Idaho Power's access to regional markets. Additional capacity on the transmission system serving Idaho also may become available as a result of the retirement of out-of-state coal units serving Idaho Power. This available transmission capacity will expand access to the regional markets that are increasingly seen as the key to successful integration of a growing penetration of renewable generation.

VII. REFINEMENTS TO THE IRP METHOD

Q: You have stated above that ICL and the Sierra Club believe that the IRP Method is working well. Please elaborate.

A: In my judgment, the IRP method accurately predicts future avoided energy costs, and captures the need for additional generation through the timing of capacity payments. As a result, there is no need to shorten the term of PURPA contracts out of a concern that these contracts will be a future burden for ratepayers in Idaho. To the contrary, as discussed above, they offer many benefits to consumers that are not captured in the avoided cost price.

Q: Are there ways in which the IRP method might be improved so that it would reflect Idaho Power's avoided costs even more accurately?

A: Possibly. ICL and the Sierra Club recommend that the Commission consider allowing Idaho Power to include the energy and capacity contribution of each QF with a signed contract when calculating the avoided cost values for the next subsequent QF, instead of updating its capacity position just once a year. In essence, this refinement would allow more frequent updates to Idaho Power's capacity position. This more granular calculation of avoided costs based on the utility's up-to-date capacity position and need could further increase the accuracy of the IRP method, and at least partially address Idaho Power's concerns in this regard.

Q: Does this conclude your direct testimony?

A: Yes, it does.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-15-01

CASE NO. AVU-E-15-01

CASE NO. PAC-E-15-03

Idaho Conservation League and the Sierra Club

Direct Testimony of R. Thomas Beach

Exhibit 301

R. Thomas Beach C. V.

IPC-E-15-01
BEACH, Di
Idaho Conservation League and Sierra Club

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has participated actively in most of the major energy policy debates in California, including renewable energy development, the restructuring of the state's gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning California's large independent power community. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of PURPA.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning California's Renewable Portfolio Standard program, including the calculation of the state's Market Price Referent for new renewable generation. He has also worked for the solar industry on the creation of the California Solar Initiative (the Million Solar Roofs), as well as on a wide range of solar issues in other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, electric transmission and interconnection issues, property tax matters, standby rates, QF efficiency standards, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English. Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CPUC

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    · *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    · *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    · *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    · *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    · *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    · *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

- *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

- *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

- *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

- *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

- *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

- *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

- *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

- *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

- *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

- *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

- *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    · *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    · *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    · *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    · *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    · *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    · *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    · *Natural gas pipeline safety policies and costs*

75. a. Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar Energy Industries Association and the Solar Alliance, (Docket No. 09AL-299E – October 2, 2009).

    - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Vote Solar Initiative and the Interstate Renewable Energy Council, (Docket No. 11A-418E – September 21, 2011).

    - *Development of a community solar program for Xcel Energy.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

    - *Costs and benefits of net energy metering in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

    - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

    - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)

    - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

    - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)

   - *Standby rates for net-metered solar customers, and the cost-effectiveness of net energy metering.*

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony of R. Thomas Beach on Behalf of Geronimo Energy, LLC. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

   - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony of R. Thomas Beach on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-15-01

CASE NO. AVU-E-15-01

CASE NO. PAC-E-15-03

Idaho Conservation League and the Sierra Club

Direct Testimony of R. Thomas Beach

Exhibit 302

Idaho Power Responses to:

A. Commission Staff Request No. 2

B. ICL/Sierra Club Request No. 5

C. Commission Staff Request No. 18

D. J.R. Simplot Request No. 16

REQUEST NO. 2: Idaho Power's Petition states on page 21 "The continued and unchecked addition of extremely large amounts of intermittent wind and solar QF generation onto Idaho Power's system at long-term fixed rate prices when the Company has no need for additional generation inflates power supply costs borne by customers and degrades the reliability of the system." How does Idaho Power expect the recent addition of 461 MW of solar contracts to impact customers' retail rates? Does the Company expect rates will have to increase once the contracted solar projects are online and Idaho Power is purchasing the energy? If Idaho Power expects rates will increase, has the Company estimated the approximate rate or revenue requirement increase? If so, please provide the estimate.

RESPONSE TO REQUEST NO. 2: The Company expects 100 percent of the costs associated with the additional 461 MW of solar contracts to be collected from customers through retail rates. The extent to which retail rates would change as a result of the referenced solar contract costs requires a modeled forecast of power supply expenses that must include a comprehensive set of assumptions that is not known today and is subject to debate. To date, Idaho Power has not performed such an analysis.

The Company's request in this case is to prospectively limit the contract term for projects above the established surrogate avoided resource ("SAR") eligibility cap and seeks to mitigate the risk of uncertain rate impacts that exist associated with additional generation that is not needed to satisfy any near-term capacity or energy requirements.

The response to this Request is sponsored by Mike Youngblood, Regulatory

Projects Manager, Idaho Power Company.

REQUEST NO. 5: Please reference the Direct Testimony of Mr. Aliphin Exhibit No. 8 that shows certain FERC account expenses for the years 2010, 2012, and 2013:

a. Do FERC Account Nos. 501 (coal) and 547 (gas) include either fixed O&M costs, incremental capital additions, or the costs associated with the return on rate base and associated taxes for Idaho Power-owned coal and gas plants?

b. Please provide the fixed O&M costs, incremental capital additions, and the revenue requirements associated with the return on rate base and associated taxes for Idaho Power-owned coal and gas plants for the years 2010, 2012, and 2013. For gas plants, please also include gas pipeline capacity or reservation costs if not included in Account 547.

c. If available, please provide the data in Exhibit No. 8, plus the data requested in Part (a) of this question, for the years 2011 and 2014.

RESPONSE TO REQUEST NO. 5:

a. No. The cost items that fall within Federal Energy Regulatory Commission ("FERC") Accounts 501 (coal) and 547 (gas) are those items which fall within the FERC Uniform System of Accounts definitions for those respective FERC accounts. In this case, they are fuel-related expenses for the production of steam for the generation of electricity (FERC Account 501) and cost of fuel delivered at the station of all fuel, such as gas, oil, kerosene, and gasoline used in other power generation (FERC Account 547). They do not include fixed operation and maintenance ("O&M") costs, incremental capital additions, or the costs associated with the return on rate base and associated taxes.

b. Fixed O&M costs, incremental capital additions, and the revenue requirements associated with the return on rate base and associated taxes for Idaho Power-owned coal and gas plants are included as part of a comprehensive cost-of-service study conducted in the preparation of a general rate case; they are not determined individually or on an annual basis. As such, these items were included in the comprehensive class cost-of-service studies filed in the Company's 2008 and 2011 general rate cases (Case Nos. IPC-E-08-10 and IPC-E-11-08, respectively), as well as the rate increase determination due to the inclusion of the Langley Gulch power plant (Case No. IPC-E-12-14). These studies can be found in the documents filed by the Company in the respective cases, which are located on the Commission's website at the following addresses:

Year 2010— Case No. IPC-E-08-10
http://www.puc.idaho.qov/fiteroom/cases/summary/l PCEO8I
0.htm I

Year 2012— Case No. IPC-E-11-08
http://www.puc.idaho.qov/fileroom/cases/summary/IPCEI I
08.html

Year2O13—Case No. IPC-E-12-14
http :Ilwww.puc.idaho.gov/fileroom/cases/summary/l
PCE1214.html

c. The information requested for 2011 is equivalent to the information for 2010. The information requested for 2014 is equivalent to the information for 2013.

The response to this Request is sponsored by Mike Youngblood, Regulatory Projects Manager, Idaho Power Company.

REQUEST NO. 18: On page 22, the Petition states that “- - - the risk and potential harm increases, the longer the price estimates are locked in.” Does Idaho Power believe long-term, locked-in price estimates could potentially benefit Idaho Power in some circumstances?

RESPONSE TO REQUEST NO. 18: No.

The response to this Request is sponsored by Mike Youngblood, Regulatory Projects Manager, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 16: Has the Company investigated the impacts of Idaho Power joining the PacifiCorp-California ISO energy imbalance market as a potential way to reduce costs associated with intermittent generation or for any other reasons? If not, why not? Please provide all studies or analyses of the impacts of Idaho Power joining the PacifiCorp-California ISO energy imbalance market.

ANSWER TO REQUEST FOR PRODUCTION NO. 16: Idaho Power has not studied participation in the PacifiCorp-CAISO energy imbalance market primarily because Idaho Power does not have any transmission rights that would allow it to participate in the PacifiCorp-CAISO energy imbalance market

Idaho Power is participating in the Northwest Power Pool efforts to study the feasibility of an intra-hour market similar to an energy imbalance market referred to as the Security Constrained Economic Dispatch and will continue to evaluate the PacifiCorp-CAISO energy imbalance market and other market opportunities as they become available.

The response to this Request is sponsored by Tess Park, Director Load Serving Operations, Idaho Power Company.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-15-01

CASE NO. AVU-E-15-01

CASE NO. PAC-E-15-03

Idaho Conservation League and the Sierra Club

Direct Testimony of R. Thomas Beach

Exhibit 303

California ISO/NVEnergy Energy Imbalance Market Fact Sheet

California ISO
Shaping a Renewed Future

NVEnergy
A MIDAMERICAN ENERGY HOLDINGS COMPANY

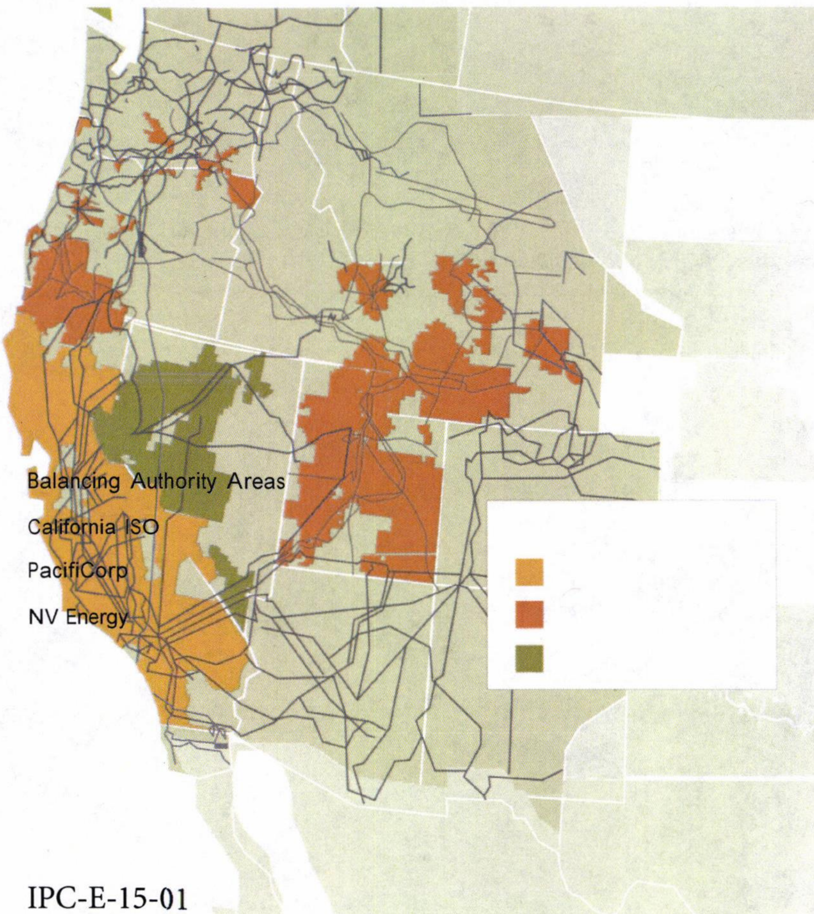
Seven states participating in the Energy Imbalance Market

The ISO and PacifiCorp launched into the first western real-time energy balancing market into operation on November 1, 2014. NV Energy has obtained approval from both the Federal Energy Regulatory Commission (FERC) and the Public Utilities Commission of Nevada (PUCN) and will go live with the Energy Imbalance Market (EIM) in fall of 2015. Studies conducted by both companies of their participation in EIM show significant economic and reliability benefits that accrue to customers in the NV Energy, PacifiCorp, and ISO areas. Participants in the EIM can leverage generation resources across the entire EIM region, with the added benefit of more frequent dispatching in real time to optimize available energy supplies. The EIM is an important tool for operators across the region to facilitate increased integration of renewable resources.

Background

The ISO announced a partnership with Portland-based PacifiCorp in February 2013 to develop an EIM that would operate across participating balancing areas. Following a robust public stakeholder process, the ISO developed a market design that was approved by the ISO Board in November 2013. PacifiCorp began participating in the EIM in November 2014. With NV Energy, the expanded EIM would cover seven states and over 44 million people.

Reliability benefits



The EIM strengthens grid reliability by balancing supply and demand closer to when electricity is consumed and by allowing system operators real-time visibility across neighboring grids. The ISO is leveraging its existing market systems to identify fluctuations in supply and demand, and then automatically find the best resource to meet current needs across a larger region. This, in turn, optimizes the interconnected high-voltage system as market systems automatically manage congestion on transmission lines.

Renewable integration benefits

While the nation's energy supply becomes more diverse, regional coordination and finely tuned dispatches become more important as changing weather conditions produce variability in wind and solar power generation. An EIM improves the ability to manage resource output deviations, smoothing out power flows in real time so that renewable energy is effectively *integrated onto the grid. By combining the NV Energy, PacifiCorp, and ISO's diverse portfolio, the seven-state EIM will make it possible to share more variable renewable resources such as wind or solar during times of under- or overgeneration.*

Easy and economical entry and exit

Studies indicate that the benefits to all customers in the seven-state EIM footprint outweigh the costs of participating in the EIM. In addition, an EIM participant can choose to leave the market at any time with no exit fees.

Preserving autonomy

EIM entities such as PacifiCorp, NV Energy and other participating balancing authorities maintain operational control over their generating resources, retain all their obligations as a balancing area, and must still comply with all regional and national reliability standards. For example, obligations to provide reliability compliance, ancillary services, physical scheduling rights and bilateral trades do not change with EIM.

A market-based solution

The ISO already operates a successful real-time fifteen minute market with five-minute dispatch capability. This is a tried and true service that exists in a similar form in two-thirds of the United States, particularly in the Northeast and Midwest as well as much of Canada. This partnership signals continuing interest from other balancing areas in joining what is already working effectively to lower costs and at the same time expanding the pool of resources available to meet supply and demand needs in real time. It is a voluntary and natural step toward the more efficient management of energy systems for the benefit of customers.

Governance

The ISO EIM expansion requires that all entities, whether inside or outside California, are given a voice in the decision-making process going forward. In May 2014 the ISO Board of Governors appointed the EIM Transitional Committee that is working towards the development of a long term independent governance proposal that will go through a stakeholder process in 2015. The Board advisory committee is composed of 9 members who were nominated by industry stakeholders and two representatives from PacifiCorp and NV Energy. They have committed to work in an open and transparent manner and be inclusive of a wide range of stakeholders making the EIM a truly western market and encourage broad participation.

Next steps

Work is underway to integrate NV Energy into the EIM in October, 2015. The ISO began publishing in February 2015 quarterly reports of the actual EIM benefits based on actual operating data.

Beginning in 2014 and continuing in 2015, NV Energy will conduct a stakeholder process for transmission customers and other stakeholders to make changes to its open access tariff in order to implement the EIM. They will then seek FERC acceptance in mid-2015.

During 2015, the ISO will complete the stakeholder process for Year 1 Enhancements to EIM, to address FERC compliance, commitments made during the original stakeholder process, and others identified during implementation. Continued stakeholder involvement will be critical to the success of the EIM by offering valuable input and support to expand a market that can be leveraged to more effectively use resources in the West.

CERTIFICATE OF SERVICE

I hereby certify that on this 22nd day of April 2015, I delivered true and correct copies of the DIRECT TESTIMONY OF ADAM WENNER, DIRECT TESTIMONY OF R. THOMAS BEACH, and, EXHIBITS 301 – 303 on behalf of the Idaho Conservation League and the Sierra Club the following persons via the method of service noted:

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