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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of changes to Renewable Avoided Costs Methodology for Qualifying Facilities Projects Larger than Three Megawatts	**DOCKET NO. 12-035-100** **Utah Clean Energy Exhibit 4.0(D)**

DIRECT TESTIMONY OF SARAH WRIGHT
ON BEHALF OF
UTAH CLEAN ENERGY

[METHODOLOGY PROCEEDING]

March 29, 2013

RESPECTFULLY SUBMITTED,
Utah Clean Energy

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Sophie Hayes
Attorney for Utah Clean Energy

INTRODUCTION

Q: Please state your name and business address.

A: My name is Sarah Wright. My business address is 1014 2nd Ave, Salt Lake City, Utah 84103.

Q: Did you file Direct, Rebuttal, and Surrebuttal Testimony on behalf of Utah Clean Energy in the first phase of this docket (regarding the proposed stay of the avoided costs methodology)?

A: Yes.

Q: Please review your professional experience and qualifications.

A: I am the founder and director of Utah Clean Energy. Through my work with Utah Clean Energy over the last 11 years, I have been involved in a number of regulatory dockets, including Integrated Resource Planning, rate cases, tariff filings, and other dockets relating to energy efficiency, renewable energy, and net metering. I serve on Rocky Mountain Power's DSM Steering Committee and both Rocky Mountain Power's and Questar Gas Company's DSM Advisory Committees.

I have over ten years of energy policy experience working on state, local, and national energy policy, providing expertise and policy support for renewable energy and energy efficiency. I have served on numerous energy policy working groups and taskforces, including the Energy Efficiency and Energy Development Committees supporting Governor Herbert's Energy Task Force and Ten Year Energy Plan; the Governor's Utah Renewable Energy Zone Task Force; Governor Huntsman's Energy Advisory Council and Blue Ribbon Climate Change Advisory Council; Utah's Legislative Energy Policy Workgroup, and Salt Lake City's Climate Action Task Force. I also served on the State of Utah, Division of Air Quality PM2.5 State Implementation Plan workgroup. Currently, I serve on the Board of Directors for Interwest Energy Alliance and the Interstate Renewable Energy Council Regulatory Advisory Board for the US Department of Energy Sunshot Initiative.

For15 years prior to founding Utah Clean Energy, I was an occupational health and environmental consultant working on occupational health and ambient air quality issues for a wide variety of commercial, industrial, and governmental clients across the west.

I have a BS in Geology from Bradley University in Peoria, Illinois and a Master of Science in Public Health from the University of Utah in Salt Lake City.

OVERVIEW AND CONCLUSIONS

Q: What is Utah Clean Energy's interest in this phase of this docket?

A: Utah Clean Energy strives to create a safer, more efficient, cleaner, and smarter energy future. We enable increased utilization of energy efficiency, distributed generation, and utility-scale renewable energy. The Public Utility Regulatory Policy Act (PURPA) is an important mechanism for facilitating renewable energy development in Utah. Indeed, as state renewable portfolio standards are met, PURPA's ability to encourage renewable energy development will become more and more critical for diversifying utility resource mixes and reducing our reliance on fossil fuels. Utah Clean Energy's interest in this docket is to facilitate beneficial renewable energy development in Utah through appropriate evaluation and calculation of avoided costs.

As I mentioned in my testimony during Phase 1 of this proceeding, PURPA—no less relevant in Utah today than it was in 1978—highlights the importance of relying less on fossil-fueled resources, the reluctance of traditional utilities to purchase electricity from small power producers, and the resulting need to encourage small power production through laws and regulations. Furthermore, although natural gas prices are currently low, the objective of relying less on fossil-fueled resources is critical for Utah, given the contribution of fossil fuels to climate change, uncertainties around coal plant retirements, as well as the risks of fuel price volatility and heavy reliance on a non-diverse resource mix.

Q: What is the purpose of your direct testimony?

A: I will respond to the Company's witnesses, Gregory N. Duvall and Paul H. Clements. I will also make recommendations for avoided costs pricing for renewable QFs.

Q: What is the Company's proposal for avoided cost pricing for renewable QFs?

A. The Company proposes to eliminate the IRP-based, wind-specific pricing methodology (Market Proxy method), use the Proxy/PDDRR method for all resources—utilizing the 2010 wind integration study for both solar and wind resources, change the capacity value calculation (used in the IRP as well as avoided cost calculations), and keep all RECS associated with QF development. Specifically, the issues RMP wants addressed are the following:

1. Whether the Market Proxy method continues to produce avoided costs that are in the public interest, including:
    a. The definition of the IRP target;
    b. The timing of the need for renewable resources; and
    c. The treatment of resources acquired for RPS compliance in other states.
2. Proxy/PDDRR method for renewable QFs, including:

   a. The capacity value of variable resources;
   b. The type of resource deferred; and
   c. Integration costs.
3. The ownership of RECs from renewable QFs under the Proxy/PDDRR method, including the right of a QF to buy back RECs and the associated price.

Q. What of these issues will you be addressing in your testimony?

A. I will address all three of these issues. I also address the high level of risk and uncertainty that utilities, utility planners, and utility regulators face at this time regarding fuel costs, greenhouse gases and climate changes, and the implicit risk these put on ratepayers. I argue that avoided costs should include, in addition to energy and capacity payments, payments for *avoidable* costs associated with the Company's resource decisions.

Q. Please summarize your conclusions.

A. I make the following conclusions and recommendations:

- Proper implementation of PURPA is as important now as it was when the law was passed. There are significant costs and risks associated with climate change and heavy reliance on fossil-fueled resources and front office transactions that are important to consider when evaluating avoided cost pricing.
- Appropriately pricing electricity from renewable energy QFs is critical because those resources can mitigate the costs and risks associated with traditional electricity generation and its impacts.
- The Company's resource decisions are relevant to the discussion of avoided costs: "avoided costs" should reflect actually avoidable costs, including costs the

Company would incur, absent QF generation, based on the risk profile and cost impacts of its resource procurement decisions.

- The Market Proxy method is still a sound avoided cost pricing methodology and should be used in the event that the Company's integrated resource plan selects renewable resources. I recommend a number of different alternative sources of market proxy cost information, including the Company's IRP.
- The Company's proposed Proxy/PDDRR method results in "bare-bones" avoided cost pricing that does not reflect true capacity value or actually avoidable costs provided by renewables QFs. I recommend use of a modified Proxy/PDDRR method when renewable resources are not selected in the Company's IRP preferred portfolio.
- I recommend that the Company utilize its most recent wind integration study for calculating wind integration costs. Solar should not be charged an integration cost.
- QFs should keep RECs associated with their renewable electricity production.

AVOIDED COSTS SHOULD INCLUDE RISK-ASSOCIATED AVOIDABLE COSTS

Q. What is Utah Clean Energy's position regarding appropriate avoided cost pricing?

A. Avoided costs should maintain ratepayer neutrality and not discriminate against QFs. "Avoided costs" does not necessarily mean the most stripped, barest costs the Company can estimate it will avoid. Rather, avoided costs should be a reflection of actually avoidable costs, including costs the Company would otherwise incur in the absence of QF generation, based on the risk profile of its resource procurement decisions.

Q. Why is risk relevant to avoided cost pricing?

A. Although avoided cost pricing explicitly includes compensation for avoided energy and capacity costs, these are not the only costs a utility avoids by purchasing electricity from a renewable QF. There are significant risk-associated costs that are avoidable through renewable QF electricity purchases.

Q. What risk-associated costs are avoidable through renewable QF purchases?

A. Renewable QFs offer many risk mitigating benefits to ratepayers. Utilities purchase electricity from renewable QFs through typically long-term power purchase contracts. Because energy resources such as wind, solar, and geothermal have no fuel costs and do not emit pollution or greenhouse gasses, renewable QFs provide valuable long-term risk mitigation against rising fuel costs, fuel price volatility, environmental compliance costs, potential carbon regulation costs, and the actual costs of a changing climate.

Risks associated with rising fuel costs and fuel price volatility have actual costs associated with them—costs that are avoidable by displacing or deferring fossil-fueled generation through purchases from renewable QFs. Similarly, environmental and carbon regulations impose real but avoidable costs on ratepayers. And although the costs of addressing our changing climate are increasing, we may still avoid costs associated with climate impacts affecting electricity generation. Avoided cost rates for purchasing electricity from renewable QFs should include these avoidable costs.

If we fail to pay renewable QFs for their full capacity value, long-term hedge value, and avoided environmental costs, and instead pay only for thermal-resource valued energy, we will miss important opportunities to mitigate costly risks in a responsible manner for ratepayers. By purchasing renewable electricity from QFs, the utility not only avoids risk by investing in fuel-free electricity generation, but by diversifying its resource portfolio.

Avoidable climate change costs

Q. Please describe costs of climate change associated with fossil-fueled resources.

A. With regard to climate change, electricity generation is the largest source of greenhouse gas emissions in the United States. 32% of US greenhouse gas emissions are a result of fossil-fueled electricity generation.[1]

Americans are already incurring significant costs due to climate change.[2] The impacts of climate change are occurring faster than scientific models have predicted.[3] Although scientists are reluctant to relate a single weather event specifically to climate change, the frequency of costly weather related storms is increasing dramatically and systemically due to climate change.[4] Weather events in 2011 and 2012 were the most extreme on record. The National Oceanic and Atmospheric Administration (NOAA) keeps a record of extreme weather events with cost impacts over $1 billion: economic losses due to the 11 most costly weather events in 2012 have not been finalized, but in 2011, there were 14

[1] *Climate Change Indicators in the United States, 2012*, U.S. EPA, December 2012, 13, available at: http://www.epa.gov/climatechange/science/indicators/download.html.

[2] *See, e.g.,* Coral Davenport, *The Scary Truth About How Much Climate Change is Costing You*, The National Journal (February 17, 2013), available at: http://www.nationaljournal.com/member/magazine/the-scary-truth-about-how-much-climate-change-is-costing-you-20130207.

[3] *See, e.g.* Heather Stewart and Larry Elliot, *Nicolas Stern: 'I got it* Wrong *on Climate Change—It's Far Worse*,' The Observer (January 26, 2013), available at: http://www.guardian.co.uk/environment/2013/jan/27/nicholas-stern-climate-change-davos.

[4] Scientists point out that natural climate variability plays a role in extreme weather events; however, scientists also explain that the backdrop of global warming caused by humanity's greenhouse gas emissions makes weather extremes more likely. For an entertaining illustration of this concept, see a short video comparing climate change to steroids in baseball, available at https://www2.ucar.edu/atmosnews/attribution/steroids-baseball-climate-change.

events that each cost over a billion dollars, at a cost of $60.6 billion in economic losses.[5] In 2012, Congress allocated $61 billion just to deal with superstorm Sandy.[6] The Government Accounting Office recently added climate change to its "high risk list" of significant federal government financial risk exposure.[7]

With specific regard to Utah and PacifiCorp's service territory, there are observed climate change indicators that are particularly significant. For example, unusually hot summer days have become more common (and the occurrence of unusually hot summer nights has increased even more); more precipitation is falling in the form of rain than snow, which impacts snow cover, snow pack, streamflows, and run-off; the largest observed decreases in snow pack are in Oregon, Washington, and Northern California; low stream flows in the Pacific Northwest have decreased (streams carry less water); winter stream run-off is happening earlier; and droughts have increased due to reduced snow pack and snow cover.[8] Each of these has impacts on PacifiCorp's electricity generation, including its significant hydropower resources, as well as its thermal resources (which rely on water for cooling). These changes are projected to increase, with increasingly costly impacts to the Company's ratepayers.

According to the recently released Federal Advisory Committee *Draft Climate*

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[5] NOAA National Climatic Data Center's Billion Dollar Weather/Climate Disasters database, available at: http://www.ncdc.noaa.gov/billions/events.

[6] *See, e.g.,* Coral Davenport, *The Scary Truth about How Much Climate Change is Costing You*, The National Journal (February 17, 2013), available at: http://www.nationaljournal.com/member/magazine/the-scary-truth-about-how-much-climate-change-is-costing-you-20130207.

[7] *Limiting the Federal Government's Fiscal Exposure by Better Managing Climate Change Risks*, Government Accountability Office (2013), available at: http://www.gao.gov/highrisk/limiting_federal_government_fiscal_exposure.

[8] *Climate Change Indicators in the United States, 2012*, U.S. EPA, December 2012, *passim*, available at: http://www.epa.gov/climatechange/science/indicators/download.html.

Assessment Report,[9] there is "high confidence" that the following climate change impacts in the Southwest region will increase:

- Snowpack and streamflows are projected to decline, decreasing water supply for cities, agriculture, and ecosystems[10];
- Increased warming, droughts, insect infestations, tree death, and fuel accumulation will increase wildfires, increasing risk to communities and infrastructure across extensive areas[11];
- Higher temperatures in cities will exacerbate health threats as well as increase risk of disruptions to urban infrastructure, electricity generation, and water supplies;[12]
- Surface and groundwater supplies are already affected and are expected to be reduced further by declining runoff and groundwater recharge trends, increasing the likelihood of water shortages for many off-stream and in-stream water uses[13]; and
- Utah and the upper Midwest are projected to have the highest temperature increases in the United States under any emission scenario (*see* Figure 1).[14]

[9] *Draft Climate Assessment Report*, National Climate Assessment and Development Advisory Committee (January 2013), available at: http://ncadac.globalchange.gov/.
[10] *Draft Climate Assessment Report*, National Climate Assessment and Development Advisory Committee (January 2013), 687, available at: http://ncadac.globalchange.gov/.
[11] *Draft Climate Assessment Report*, National Climate Assessment and Development Advisory Committee (January 2013), 687, available at: http://ncadac.globalchange.gov/.
[12] *Id.*
[13] *Id.* at 108.
[14] *Id.* at

Figure 1

Source: *Draft Climate Assessment Report*, National Climate Assessment and Development Advisory Committee (January 2013), 38, available at: http://ncadac.globalchange.gov/.

Caption: The largest uncertainty in projecting future climate change is the level of emissions. The most recent model projections (shown [below]) take into account a wider range of options with regard to human behavior; these include a lower emissions scenario (RCP 2.6, top left) than has been considered before. This scenario assumes rapid reductions in emissions – more than 70% cuts from current levels by 2050 – and the corresponding smaller amount of warming. On the high end, they include a scenario that assumes continued increases in emissions (RCP 8.5, bottom right) and the corresponding greater amount of warming. On the high end, they include a scenario that assumes continued increases in emissions (RCP 8.5, bottom right) and the corresponding greater amount of warming. Also shown are temperature changes (°F) for the intermediate scenarios RCP 4.5 (top right, which is most similar to B1) and RCP 6.0 (bottom left, which is most similar to A1B; see the Appendix.) Projections show change in average surface air temperature in the later part of this century (2071-2099) relative to the late part of the last century (1971-2000). (Figure source: NOAA NCDC / CICS-NC. Data from CMIP5.)

BOX: Newer Simulations for Projected Temperature (CMIP5 models)

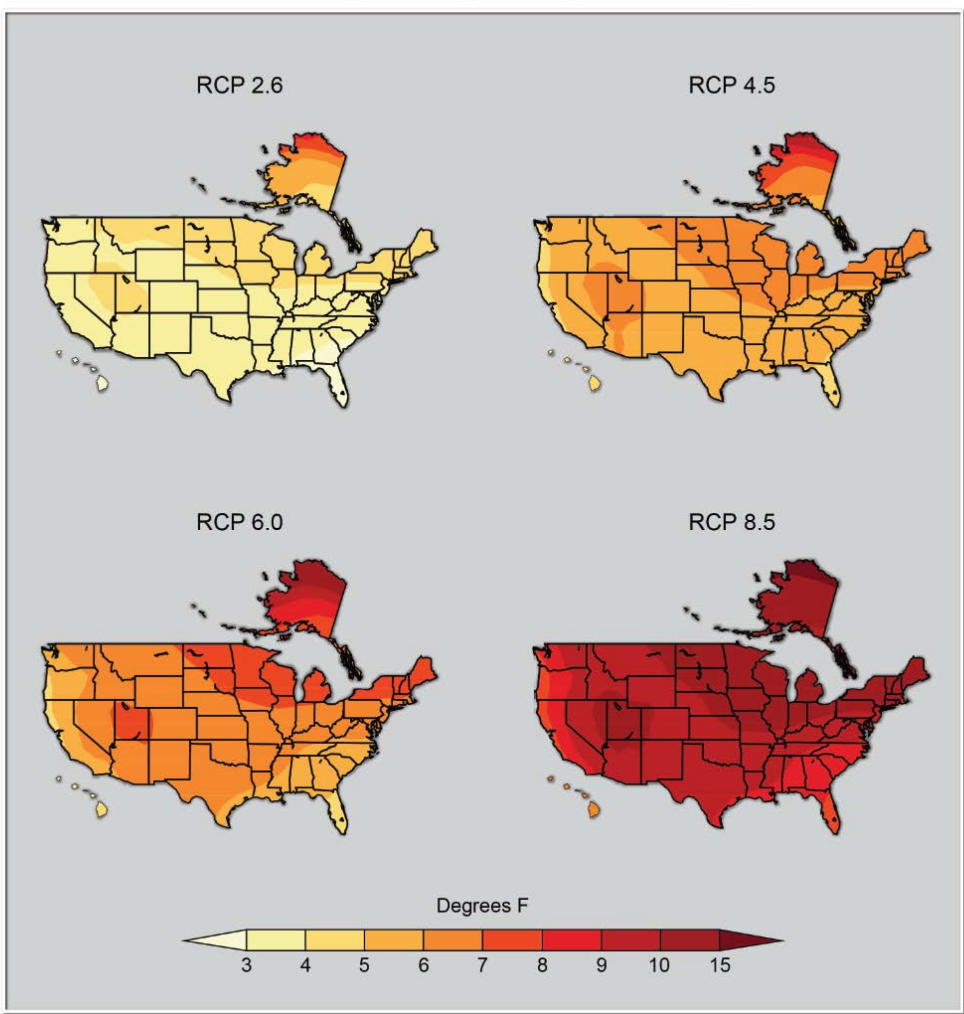


Figure 2.8:

With specific regard to electricity generation, the Draft Report notes:

- "Power plant cooling is expected to be affected by changes in water supply availability in areas where surface water supplies are diminishing and by increasing water temperatures. Higher water temperatures affect both the effectiveness of electric generation and cooling processes and the ability to discharge heated water to streams from once-through cooled power systems."[15]
- "Hydropower contributes . . . up to 60% to 70% in the Northwest . . . . Climate change is expected to affect hydropower *directly* through changes in runoff . . . and *indirectly* through increased competition with other water uses."[16]

Furthermore, extreme weather events (which are projected to increase) will disrupt energy supply, wildfires will disrupt energy transmission, higher summer temperatures will increase energy demand, and changes in water availability will constrain energy production.[17]

Q. How do purchases from renewable QFs help avoid costs associated with climate change?

A: Fuel free renewable energy sources offer an important means to reduce greenhouse gas emissions and contribute to climate stabilization. Importantly, renewable resources also

[15] *Draft Climate Assessment Report*, National Climate Assessment and Development Advisory Committee (January 2013), 122, available at: http://ncadac.globalchange.gov/.
[16] *Id.* at 124.
[17] *Id.* at 167-183.

mitigate costs associated with heavy reliance on fossil fuels. For example, the draft NCA report illustrates how renewable resources mitigate costs associated with climate impacts:

> The Southwest's abundant geothermal, wind, and solar power-generation resources could help transform the region's electric generation system into one that uses substantially more renewable energy. This transformation has already started, driven in part by renewable energy portfolio standards adopted by five of six Southwest states, and renewable energy goals in Utah. . . . As the regional climate becomes hotter and, in parts of the Southwest, drier, there will be less water available for the cooling of thermal power plants, which use about 40% of the surface water withdrawn in the U.S. The projected warming of water in rivers and lakes will reduce the capacity of thermal power plants, especially during summer when electricity demand skyrockets. Wind and solar photovoltaic installations could substantially reduce water withdrawals. A large increase in the portion of power generated by renewable energy sources may be feasible at reasonable costs and could substantially reduce water withdrawals.[18]

<u>Avoidable fuel risk mitigation costs</u>

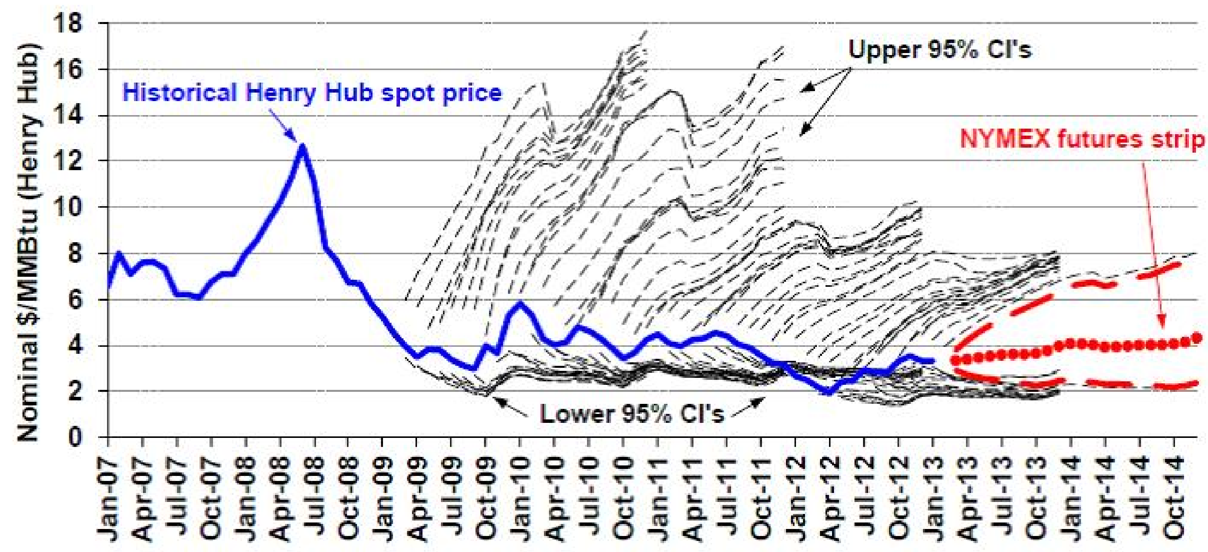
Q. Please describe risks associated with fuel prices.

A. Currently, natural gas prices are at historic lows, thanks to horizontal drilling and fracking technologies that have "unlocked" shale gas. This has led to a boom in supply and an increase in natural gas-fired electricity generation, as well as a switch from coal to gas. Given these low cost projections, it is likely that more and more electricity generation will be gas-fired. Although gas prices are projected to remain low for several years, forward price curves nevertheless all slope inexorably upward. Natural gas prices are typically very volatile and hard to lock in over longer terms. Additionally, with no significant room to decrease, risk associated with natural gas prices is asymmetrical, being skewed to the upside because prices have almost nowhere to go but up.

[18] *Draft Climate Assessment Report*, National Climate Assessment and Development Advisory Committee (January 2013), 692, available at: http://ncadac.globalchange.gov/ (citations omitted).

Figure 2

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



Source: EIA 2009-2013

Figure 6. History of 95% Confidence Intervals Around Natural Gas Futures Strip

Some risks associated with natural gas are price volatility, price increases, and a tendency to reduce resource diversity by heavy reliance on natural gas.

These risks are exacerbated by other factors that are less well-known: increased supply of natural gas may lead the United States to export into the global market, which would have the impact of raising prices; there is an insufficient track record for fracking, but some evidence is starting to show that shale wells may deplete more rapidly than expected or that costs to recover additional gas over time will be greater than expected; and because of concerns over environmental/water impacts of fracking, as well as mounting evidence of alarming levels of fugitive methane emissions (that counteract any greenhouse gas emission benefit natural gas has over coal), new environmental regulations could also increase costs.

Q. How do purchases from renewable QFs help avoid fuel risk?

A. Purchases from renewable QFs avoid fuel price risk both by diversifying a utility's resource mix and by locking in stable prices over long terms. Although utilities can mitigate fuel price risk through conventional hedging instruments, there is generally no market for hedging arrangements longer than five years, ten at the most. On the other hand, renewable power purchase agreements are generally long term (20 year- or more) contracts with either flat or decreasing prices (many renewable PPAs do not include escalators for inflation, the result being declining energy prices in real terms over the contract term). A diverse resource mix is less vulnerable to changing circumstances than one heavily dependent on a single resource.

Q. What is your recommendation for avoidable risk-associated costs?

A. Below, in response to the Company's issues, I recommend that renewable QFs receive compensation for avoided risk-associated costs.

ISSUE 1: WHETHER THE MARKET PROXY METHOD CONTINUES TO PRODUCE AVOIDED COSTS THAT ARE IN THE PUBLIC INTEREST

Q. What is UCE's position regarding the Market Proxy method?

A. The Market Proxy method is a sound method, based on least cost, least risk planning; however, Utah Clean Energy is concerned that, given current planning and modeling assumptions—for example, low gas prices, carbon costs that are low and start late,[19] projected discontinuance of renewable energy incentives,[20] and a proposed changed capacity valuation methodology—the IRP is unable to recognize the long-term risk mitigation benefits of renewable resources. As a result, portfolio development results call for new resources (excluding DSM) composed 94%-97% of new gas resources and front office transactions (FOTs),[21] which is risky given current low natural gas price projections.

Q. Mr. Duvall states that the Market Proxy method is no longer in the public interest due to the flawed definition of the IRP target and the impact of the timing of the need for new resources. (Direct Testimony of Greg Duvall, lines 78-80) Do you agree with his assessment?

A: No. Utah Clean Energy has explained our position on the IRP target in prior testimony and comments in this Docket. As long as renewables are selected in the IRP, the IRP target remains the cumulative amount of renewables called for over the planning horizon,

[19] PacifiCorp's assumptions for greenhouse gas regulations have also changed significantly since the 2011 IRP. While the impacts of climate change are becoming more pronounced and the costs of adapting and responding to extreme weather-related events rises, the estimated cost of greenhouse gas regulation has decreased from the 2011 IRP to the current IRP, and the start time for a cost on carbon is delayed five to seven years compared to the assumptions in the 2011 IRP.

[20] Natural gas price assumptions are likely the biggest reason for a lack of selected renewable resources, but another driver of the IRP's reliance on natural gas and front office transactions could be the assumption about the expiration of federal incentives for renewable energy. Only one of the IRP Core Cases assumed the continuation of the renewable energy Production Tax Credit (PTC) past 2012 and the extension of the 30% Investment Tax Credit for solar past 2016. Ending the production tax credit for wind adds about $28/MWh to the cost of a wind project, while the elimination of the tax credit for solar adds about 30% to the cost of a solar project. Core Case C-18 assumed the PTC and ITC were extended out to 2019. However, I find the results of the resulting portfolios intriguing: wind is added in 2020 and beyond, but not before (while the PTC is still in effect). It appears that the model has other constraints, perhaps transmission or otherwise, that make it choose to wait a year and pay $28 more per MWh of wind, instead of building with the benefit of the PTC. Furthermore, the draft preferred portfolio is derived from a case where the Company is assuming "base case" regional haze requirements. If the requirements are more stringent, more coal plant retirements may be necessary, and ratepayers could be relying even more heavily on the market.

[21] The bulk of the remaining 3 to 6 percent is Utah's distributed solar incentive program.

regardless of timing. There are good reasons to acquire renewable resources earlier, particularly since ratepayers are on the hook for net power cost increases through the energy balancing account, including the following: to take advantage of federal incentives (the PTC and ITC), to secure optimal resource sites, to hedge against reliance on market purchases and fuel price risk.[22]

Q. Are you proposing use of the Market Proxy or Proxy/PDDRR method in this docket?

A. I recommend that we use a modified Market Proxy method, when renewables are included in the preferred portfolio in the IRP and the Proxy/PDDRR method with modifications when renewable energy is not included in the IRP.

Q. Mr. Duvall questions whether the market proxy should be used when the renewables in the IRP are used solely for compliance purposes in states other than Utah. What are your thoughts on this issue?

A. Whether or not renewable resources are added solely for compliance purposes should be determined in the IRP docket after a thorough review of costs and risks. If the Commission determines that renewables are added only for compliance purposes, then I would agree with Mr. Duvall that the Proxy/PDDRR method, with my proposed modifications, should be used.

[22] In PacifiCorp's draft preferred portfolio EG-2 C07, front office transactions range from 650 MW in 2013 to over 1400 MW over the planning horizon, with 16 of the 20 years relying on over 1000 MW by capacity of front office transactions.

Q: What modifications would need to be made to the Market Proxy method to make it work in the future?

A: I acknowledge Mr. Duvall's concern with the fact that, although PacifiCorp has been acquiring wind resources, there has not been a wind RFP project since 2009. An alternative approach might be to use cost assumptions that the Company uses in its IRP for the market proxy cost. Or a second alternative would be to explore the revenue streams that the Company receives for their owned wind projects, the average cost of PPAs for wind that the Company purchases through PPAs, or a weighted average by the capacity of wind PPAs from publically available contracts from other Western utilities. Furthermore, the Commission has not approved market proxies for geothermal, solar, or biomass projects. Again, we could use IRP assumptions, Company contracts where available, or publically available PPAs. Finally, regardless of methodology, renewable energy resources need to be fairly compensated for the capacity value they bring to the system, which I discuss more below.

Q. Should IRP acknowledgement be the threshold test for which method should be used?

A. That's a good question. There may need to be changes in the acknowledgement process, whereby the Commission acknowledges or doesn't acknowledge portions of the IRP or IRP action plan.

ISSUE 2: PROPER IMPLEMENTATION OF THE PROXY/PDDRR METHOD FOR RENEWABLE QFS

Q: What is Utah Clean Energy's recommendation regarding the Proxy/PDDRR method?

A: Utah Clean Energy does not oppose use of the Proxy/PDDRR method for renewable QFs if it is modified to properly value the capacity value of renewable QFs, to account for the avoided cost of mitigating fuel volatility risk, and to ensure that the inputs and assumptions are transparent and clear.

As I mentioned at the beginning of my testimony, "avoided costs" should not necessarily mean the lowest, most stripped costs the Company can estimate it will avoid. Rather, avoided costs should be a reflection of actually avoidable costs, including costs the Company would otherwise incur, based on the risk profile of its resource procurement decisions, in the absence of QF generation. At a minimum, avoided cost should include a fair capacity payment based on the capacity value the renewable QF brings to the system and a value for the long-term fuel and energy hedge that renewable energy sources provide.

To-date, only one renewable QF has been developed in Utah: the Spanish Fork Wind Project that used the Market Proxy method. There have been no renewable QF's developed using the Proxy/PDDRR method. Renewable QF projects should be paid for their value and the costs they avoid for the entire project period. This is especially important now when ratepayers are facing the risks of an uncertain future with respect to gas costs, compliance costs for coal plants, carbon costs, not to mention the costs associated with adapting to a changing climate. If we offer renewable QF's the most bare bones avoided cost rate, which undervalues the hedge and capacity value that these resources bring to the system, we are not offering renewable QFs a fair avoided cost and we are putting rate payers at higher risk.

<u>Capacity value</u>

Q: Do you agree with Mr. Duvall's assessment that the capacity value of renewable energy sources should be calculated based on their contribution during the 100 peak load hours?

A: No, I disagree with using PacifiCorp's method of calculating capacity factor during the top hundred peak hours as an approximation of capacity value for variable energy sources. This method ignores reliability benefits provided by renewable QFs. These reliability benefits are real and should be considered in determining avoided costs.[23] Furthermore, the Company's method appears to be an energy-focused, capacity factor calculation, rather than an evaluation of capacity value.

Q: What is the difference between Capacity Factor and Capacity Value?

A: Energy resources can be characterized by both a capacity factor and a capacity value. The capacity factor is used to estimate the amount of *energy* produced by a resource, while the capacity value (or credit) is a *reliability-based* calculation that assigns a value to a resource based on its ability to reduce the probability of a loss of load event (LOLE) and maintain system reliability. For example, Arizona Public Service designates a 50% capacity value for fixed-tilt solar, and a 70% capacity value for single-axis trackers in their recently updated 2012 IRP, whereas the capacity factor for those same solar resources is closer to 25%. Solar's effective *capacity value* is significant, and considerably higher than its *capacity factor*, which (depending on region and technology)

[23] *See* 18 CFR 292.304.

is more aligned with the figures the Company provided in its study—ranging from 11% to 30%. Both capacity factor and capacity value (or credit) are important for determining the value of a resource; however, capacity value is not currently being included in the avoided cost pricing method.

I agree with the Company that avoided costs calculations should be consistent with the IRP; therefore, Capacity *value* calculations should also be used in the IRP.

Q: How is capacity value determined?

A: There are two general ways to determine capacity value: one is based on approximations, while the other uses reliability-based modeling. UCE suggests that the latter is a better approach, and recommends use of the Effective Load Carrying Capability (ELCC) or the Equivalent Conventional Power (ECP) models as appropriate reliability-based calculations. Both of these methods "use power system reliability evaluation techniques which are based on Loss of Load Probability (LOLP) and Loss of Load Expectation (LOLE)."[24]

The ECP model allows for comparison against a conventional, dispatchable resource. It calculates the likelihood of LOLE with the addition of a solar resourceagainst a LOLE with a benchmark conventional generator, and then adjusts the nameplate capacity of the benchmark unit until it is equivalent to the LOLE with the solar resource. This benchmark capacity then becomes equivalent to the solar resource's ECP.

The ELCC model is more complicated to run and represents a generator's ability to effectively increase the generating capacity available to a utility while maintaining the

[24] Seyed Hossein Madaeni, Ramteen Sioshansi, and Paul Denholm, *Comparison of Capacity Value Methods for Photovoltaics in the Western United States* (NREL, July 2012), 2, available at: http://www.nrel.gov/docs/fy12osti/54704.pdf.

utility's loss of load probability. In a perfect world, dispatchable generators, with no downtime, have a relative ELCC of 100%. ELCC is statistically derived from an analysis of a series of time-coincident load demand and power generation data and takes into consideration summer and winter peak ratios.

A recent National Renewable Energy Laboratory study investigated different methods for evaluating and calculating the capacity value of solar. The report evaluated a number of methods. Please see Table 1 that includes the capacity value results for Salt Lake City presented in the study for a number of different solar installation types. All of the methods that were calculated in this study produce a capacity value well above the capacity value presented in Mr. Duvall's testimony. The average capacity value of the reported values for solar PV fixed, single-axis tracking and double-axis tracking in Salt Lake City ranges from 55.4% to 70.9%, as opposed to the 11%-26% values the Company is proposing for solar.

Table 1. Solar PV Capacity Values for Salt Lake City

	Salt Lake City Location		
Type of Photovoltaic Installation	Fixed-Axis	Single-Axis Tracking	Double-Axis Tracking
	(Percent based on AC Rating)		
Table 3. Average Annual Capacity Value of PV (% - Based on System AC Rating) with Fixed-Axis, Single-Axis, and Double-Axis Tracking in Different Locations: **ECP**	65.7	84.7	88.6
Table 3. Average Annual Capacity Value of PV (% - Based on System AC Rating) with Fixed-Axis, Single-Axis, and Double-Axis Tracking in Different Locations: **ELCC**	61.0	78.7	82.2
Table 5. Average Annual Capacity Value of PV using CF Approximation	67.7	81.4	84.4
Table 6. Capacity Value using Garver's Approximation Method	60.9	69.9	71.0
Table 7. Average Annual Capacity Value of PV (% Based on System AC Rating) with Fixed-Axis, Single-Axis and Double-Axis Tracking in Different Locations using GAM	24.7	30.7	34.3
Table 9. Average Annual Capacity Value of PV (% Based on System AC Rating) with Fixed-Axis, Single-Axis, and Double-Axis Tracking in Different Locations using the Z Method	52.4	63.9	64.9
Averages	55.4	68.2	70.9

Source: *Comparison of Capacity Value Methods for Photovoltaics in the Western United States*, July 2012[25]

[25] Seyed Hossein Madaeni, Ramteen Sioshansi, and Paul Denholm, *Comparison of Capacity Value Methods for Photovoltaics in the Western United States* (NREL July 2012), available at: http://www.nrel.gov/docs/fy12osti/54704.pdf. Attached as UCE Exhibit 4.1(D).

Q. What method do you recommend be used to calculate the Capacity Value for renewable QFs?

A: I recommend a method that values the reliability benefits that a renewable QF brings to the system, such as the Effective Load Carrying Capability (ELCC) or the Equivalent Conventional Power (ECP) method.

<u>Calculation of capacity payment</u>

Q. How should the capacity payment be calculated using the Capacity Value?

A. The capacity payment should be calculated using the capacity value for the QF resource multiplied by the total resource fixed cost payment stream.[26] In Table 2 below, I illustrate how varying the capacity value impacts the QF capacity price using the real, levelized payment stream of PacifiCorp's 423 MW "J" 1x1 combine cycle combustion turbine.

[26] The total resource fixed payment stream includes a capital cost real levelized payment plus an O&M component. As explained in testimony in Docket 03-035-14, the real levelized capacity payment stream component is a back-end loaded stream of values escalated by inflation that over the life of a plant produces the same present value as the front-end loaded payments used by a utility in traditional ratemaking. In general, PacifiCorp's QF contract term limits prevent a QF from realizing the higher back-end loaded values in the real levelized capacity payment stream.

Table 2

Illustrative Capacity Prices Using Various Capacity Credit Values
Based on 423 "J" 1x1 Combined Cycle Combustion Turbine

	Capacity Price				
	Capacity Price in $/kW-Yr @ Capacity Value of	Capacity Price in $/kW-Yr @ Capacity Value of	Capacity Price in $/kW-Yr @ Capacity Value of	Capacity Price in $/kW-Yr @ Capacity Value of	Capacity Price in $/kW-Yr @ Capacity Value of
	11.5%	**30.0%**	**50.0%**	**60.0%**	**70.0%**
Year	**$/kW-yr**	**$/kW-yr**	**$/kW-yr**	**$/kW-yr**	**$/kW-yr**
2013	$13.49	$35.19	$58.66	$70.39	$82.12
2014	$13.76	$35.90	$59.84	$71.81	$83.78
2015	$14.02	$36.58	$60.97	$73.16	$85.35
2016	$14.26	$37.20	$62.01	$74.41	$86.81
2017	$14.49	$37.80	$63.01	$75.61	$88.21
2018	$14.72	$38.41	$64.02	$76.82	$89.63
2019	$14.96	$39.03	$65.05	$78.05	$91.06
2020	$15.20	$39.65	$66.09	$79.30	$92.52
2021	$15.49	$40.40	$67.34	$80.81	$94.28
2022	$15.78	$41.17	$68.62	$82.34	$96.07
2023	$16.08	$41.95	$69.92	$83.90	$97.88
2024	$16.38	$42.74	$71.24	$85.48	$99.73
2025	$16.69	$43.55	$72.58	$87.10	$101.61
2026	$17.01	$44.38	$73.97	$88.76	$103.55
2027	$17.34	$45.23	$75.38	$90.46	$105.53
2028	$17.67	$46.09	$76.82	$92.18	$107.55
2029	$18.00	$46.97	$78.28	$93.94	$109.59
2030	$18.35	$47.86	$79.77	$95.72	$111.67
2031	$18.71	$48.82	$81.37	$97.64	$113.91
2032	$19.09	$49.80	$83.00	$99.60	$116.20

20-Year Levelized Prices (Nominal) @ 7.154% Discount Rate

$/kW	**$15.44**	**$40.27**	**$67.11**	**$80.53**	**$93.95**

Q: What resource should be used for the proxy in the capacity value calculation?

A: I recommend using the next deferrable IRP resource during periods of resource deficiency. Additionally, I recommend that pricing include a capacity payment, based on the next deferrable resource, during periods of resource sufficiency.

Q. Why do you recommend that renewables QFs receive a capacity payment during times of resource sufficiency?

A: This recommendation is a departure from current practice. But renewable QFs bring capacity value to the system and they should be compensated for that value in the avoided cost rate. Furthermore, as discussed above, preliminary results from the 2013 IRP indicate that the Company and ratepayers will rely very heavily on Front Office Transactions, so while PacifiCorp may not be planning to add a resource in the near term, there is nevertheless a need for both energy and capacity.

Avoided risk mitigation costs

Q. How do current low natural gas prices impact utility resource decisions?

A: Fracking, coupled with horizontal drilling, has resulted in a boom in shale gas development that has contributed to historically low natural gas prices. Low natural gas prices are putting downward pressure on electricity rates and leading to resource procurement decisions that heavily favor natural gas resources. This is slowing down diversification of electricity resource portfolios with renewables. For example, in the current IRP process, PacifiCorp ran a series of ‘paired’ Reference cases with the same parameters (i.e. gas price projections, carbon costs, etc.) with and without renewable portfolio requirements. In all the side-by-side paired comparison cases for Energy Gateway Scenario 2 (which is the Gateway scenario in PacifiCorp’s draft preferred portfolio) the *physical resources* added to the system for the non-RPS scenarios are greater than 90% natural gas by capacity. When you add in Front Office Transactions, the percentage of resource additions by capacity that are natural gas and Front Office Transactions is 94% or above. The only renewable resource to speak of in the non-RPS scenarios is the Utah distributed solar PV incentive program that is modeled using the utility cost.

Q. **Do you believe that this poses a risk for rate payers?**

A. Yes, this increased reliance on new gas and front office transactions, without continued diversification with fuel-free renewables, is risky to ratepayers. There is no debate about whether gas prices will rise in the future, the question is when and by how much. Heavy reliance on natural gas and market purchases puts ratepayers at risk, particularly given Rocky Mountain Power's energy balancing account (EBA) for net power costs. Renewable QFs provide the utility and ratepayers a cost-effective means to diversify the resource mix with fixed price power purchase contracts without significant upfront investments.

Q: Why should the fuel volatility risk mitigation of renewable energy be included in the Avoided Cost Methodology?

A: Renewable energy sources have no fuel costs, and therefore they act as an important hedge against fuel volatility. Utilities typically participate in short-term hedging, using a number of conventional instruments. Hedging for greater than five years is not common, and it is even more uncommon to try to hedge gas prices for 10 years or longer. However, renewable energy sources provide a twenty or twenty-plus year fuel hedge that has real value to ratepayers. Since renewables offer a hedge against fuel volatility to ratepayers, if the avoided cost methodology does not utilize a proxy method that compares wind to wind and solar to solar, etc., then the avoided cost calculation should account for the risk mitigation and avoided hedging costs that fuel-free renewable energy provides to the system and ratepayers.

To explore how a different, higher priced future would impact avoided energy costs, our consultant, Energy Strategies, ran GRID runs with an 80 MW PV plant in the Salt Lake City area. The first run used PacifiCorp's September 2012 forward price curve and the second run assumed 25% higher natural gas and energy prices starting in 2015. The capacity factor used in this analysis for illustrative purposes may be lower than the actual capacity factor for solar in Salt Lake. The 25% increase in fuel and energy costs was selected based upon a review of PacifiCorp's forward natural gas price curves[27] presented in 2013 IRP public input meetings and Energy Information Administration forward price curves as reported in a recent report by Lawrence Berkeley National Laboratory.[28] *See* Figures 4 and 5 below. As you can see from these figures, a 25% increase is well within the realm of possibility, and indeed, prices could go much higher.

The difference in the levelized energy prices produced by the GRID runs on a seasonal and monthly basis is shown in Tables 3 and 4 *below*. Table 5 is a summary table that shows the difference in the annual avoided energy prices. As you might expect, the levelized energy price produced by the 25% higher scenario is about 24% higher than the levelized energy price produced by the September 2012 OFPC scenario. This

[27] Handout from IRP Public Input Meeting: *Comparison of Natural Gas Prices: 2011 IRP vs. 2013 IRP* (October 24, 2012), available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/2013IRP_NatGas-CO2_2011v2013IRP_10-24-12.pdf.

[28] Mark Bolinger, *Revisiting the Long Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices* (LBNL, March 2013), 18, available at http://emp.lbl.gov/sites/all/files/lbnl-6103e.pdf.

demonstrates the significant costs at stake given differences in future energy and gas prices. I do not intend to argue that the future will necessarily look exactly like the second run,—only that energy prices can change dramatically with alternate price forecasts and, as discussed above, because natural gas prices cannot get much lower, the risk that prices will be higher than projected is greater than the possibility that prices will be lower.

Table 3

Avoided Energy Costs - Scheduled Hours ($/MWh)
Utah Clean Energy - Solar Resource 80.0 MW and 20.0% CF
Partial Displacement of East Side 423 MW CCCT (Type "J" 1x1)

Year	Annual	Winter Season					Summer Season				Winter Season		
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy Only													
2013	$29.19	$26.63	$25.89	$25.86	$24.54	$23.08	$24.34	$39.96	$38.21	$31.52	$28.45	$29.69	$27.80
2014	$29.27	$29.24	$30.78	$28.19	$24.82	$26.78	$25.52	$40.31	$42.64	$28.59	$24.53	$22.64	$16.15
2015	$32.54	$27.86	$28.20	$28.94	$30.24	$27.25	$29.55	$42.47	$45.80	$36.62	$34.76	$18.52	$28.46
2016	$31.51	$26.13	$29.45	$30.48	$27.16	$28.80	$30.62	$46.31	$45.32	$31.96	$30.06	$21.36	$11.79
2017	$35.57	$36.16	$20.76	$34.82	$33.74	$31.75	$34.81	$48.35	$47.72	$39.93	$35.70	$29.29	$15.70
2018	$36.94	$22.64	$30.41	$33.26	$35.77	$34.86	$37.11	$51.97	$51.71	$37.47	$41.14	$27.06	$16.02
2019	$39.42	$36.71	$29.63	$34.20	$34.80	$36.91	$43.25	$59.10	$56.50	$38.87	$40.74	$25.92	$9.33
2020	$45.99	$41.95	$32.87	$39.92	$36.80	$41.86	$49.02	$65.81	$67.21	$51.47	$48.31	$27.01	$21.94
2021	$46.48	$30.70	$33.77	$42.95	$36.89	$44.01	$47.61	$66.91	$68.90	$44.69	$51.80	$34.51	$27.70
2022	$52.34	$40.90	$42.23	$43.82	$42.04	$50.86	$57.45	$70.07	$71.18	$47.42	$55.91	$48.43	$37.35
2023	$56.16	$42.90	$44.97	$48.75	$44.86	$54.82	$61.23	$76.70	$75.68	$52.81	$57.92	$50.15	$40.02
2024	$59.10	$51.35	$53.06	$50.97	$43.75	$55.63	$64.83	$78.21	$74.62	$55.90	$61.63	$55.86	$47.83
2025	$55.53	$48.72	$51.38	$50.59	$43.46	$55.27	$63.34	$67.00	$69.42	$44.90	$59.98	$52.94	$47.84
2026	$58.89	$52.65	$54.57	$55.59	$49.01	$59.55	$62.82	$70.24	$72.87	$48.15	$63.45	$57.03	$48.42
2027	$59.46	$54.06	$55.47	$56.61	$50.33	$60.72	$65.55	$70.28	$70.51	$47.14	$63.54	$57.21	$52.16
2028	$61.48	$56.19	$57.53	$58.18	$49.81	$61.95	$71.39	$72.93	$71.81	$48.03	$65.99	$59.95	$54.36
2029	$59.68	$56.81	$57.25	$57.06	$46.89	$62.62	$63.67	$72.52	$71.47	$48.88	$64.98	$51.24	$50.62
2030	$60.11	$60.27	$61.33	$58.75	$50.26	$64.29	$63.85	$63.94	$65.42	$46.28	$68.42	$57.51	$58.68
2031	$62.31	$59.97	$62.07	$58.50	$53.18	$66.07	$68.61	$67.91	$71.25	$49.54	$68.40	$57.94	$57.43
2032	$65.92	$61.48	$62.61	$61.66	$56.46	$67.27	$70.65	$75.04	$73.95	$62.07	$69.64	$59.57	$61.31

Table 4

Avoided Energy Costs - Scheduled Hours ($/MWh)
Utah Clean Energy - Solar Resource 80.0 MW, 20.0% CF and 25% Price increase
Partial Displacement of East Side 423 MW CCCT (Type "J" 1x1)

Year	Annual	Winter Season					Summer Season				Winter Season		
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Energy Only													
2013	$29.19	$26.63	$25.89	$25.86	$24.54	$23.08	$24.34	$39.96	$38.21	$31.52	$28.45	$29.69	$27.80
2014	$29.28	$29.24	$30.78	$28.19	$24.82	$26.78	$25.52	$40.31	$42.64	$28.59	$24.53	$22.64	$16.26
2015	$37.73	$22.35	$30.90	$37.08	$33.83	$34.73	$37.17	$49.91	$54.35	$42.29	$41.97	$23.28	$21.40
2016	$38.43	$26.51	$32.73	$38.75	$40.95	$36.95	$38.28	$55.40	$54.84	$35.80	$34.44	$32.14	$8.01
2017	$42.76	$43.62	$25.74	$42.98	$44.04	$40.63	$43.63	$58.11	$57.81	$39.72	$44.21	$33.51	$16.14
2018	$44.82	$43.01	$30.37	$39.06	$47.38	$44.46	$46.98	$61.88	$61.45	$41.14	$49.35	$28.72	$17.19
2019	$49.22	$43.42	$55.48	$44.89	$50.71	$47.31	$53.45	$69.72	$67.41	$44.77	$52.05	$20.09	$5.98
2020	$55.25	$52.53	$39.36	$45.80	$45.64	$53.10	$61.83	$78.57	$79.89	$60.40	$61.04	$24.96	$23.39
2021	$57.26	$32.06	$40.74	$54.95	$46.27	$56.31	$59.88	$81.31	$83.23	$53.14	$66.69	$44.11	$32.46
2022	$65.74	$50.76	$52.10	$56.39	$53.52	$63.85	$73.21	$89.67	$85.84	$60.50	$70.88	$60.15	$45.35
2023	$70.13	$53.50	$56.17	$62.88	$55.61	$69.98	$77.98	$91.21	$90.45	$66.67	$73.29	$62.22	$57.09
2024	$72.71	$65.03	$67.96	$64.98	$54.09	$68.89	$79.02	$94.11	$89.62	$66.49	$77.93	$67.52	$60.13
2025	$71.06	$60.25	$64.41	$63.70	$53.31	$69.52	$78.38	$96.10	$87.96	$63.64	$75.45	$63.03	$55.64
2026	$73.80	$65.11	$67.40	$70.20	$59.50	$74.44	$79.49	$88.41	$91.15	$64.86	$79.82	$67.45	$59.62
2027	$74.52	$66.21	$68.44	$71.63	$60.77	$75.96	$81.09	$88.57	$90.66	$66.13	$79.67	$68.42	$57.66
2028	$77.77	$70.10	$72.28	$74.26	$64.42	$77.36	$86.04	$92.64	$91.76	$66.02	$82.76	$75.96	$65.09
2029	$75.67	$72.34	$72.99	$73.70	$57.64	$77.53	$80.96	$91.49	$89.95	$63.43	$82.06	$67.42	$64.68
2030	$77.72	$75.59	$77.82	$74.74	$63.92	$79.48	$84.59	$83.74	$92.32	$65.65	$84.69	$71.12	$68.73
2031	$80.50	$75.79	$78.30	$74.06	$67.25	$82.86	$89.42	$97.42	$91.24	$67.03	$86.13	$72.74	$70.11
2032	$84.25	$77.59	$79.14	$77.62	$72.50	$82.95	$89.61	$95.86	$96.29	$83.84	$87.80	$77.49	$77.63

Table 5

Summary Avoided Energy Price
80 MW Solar

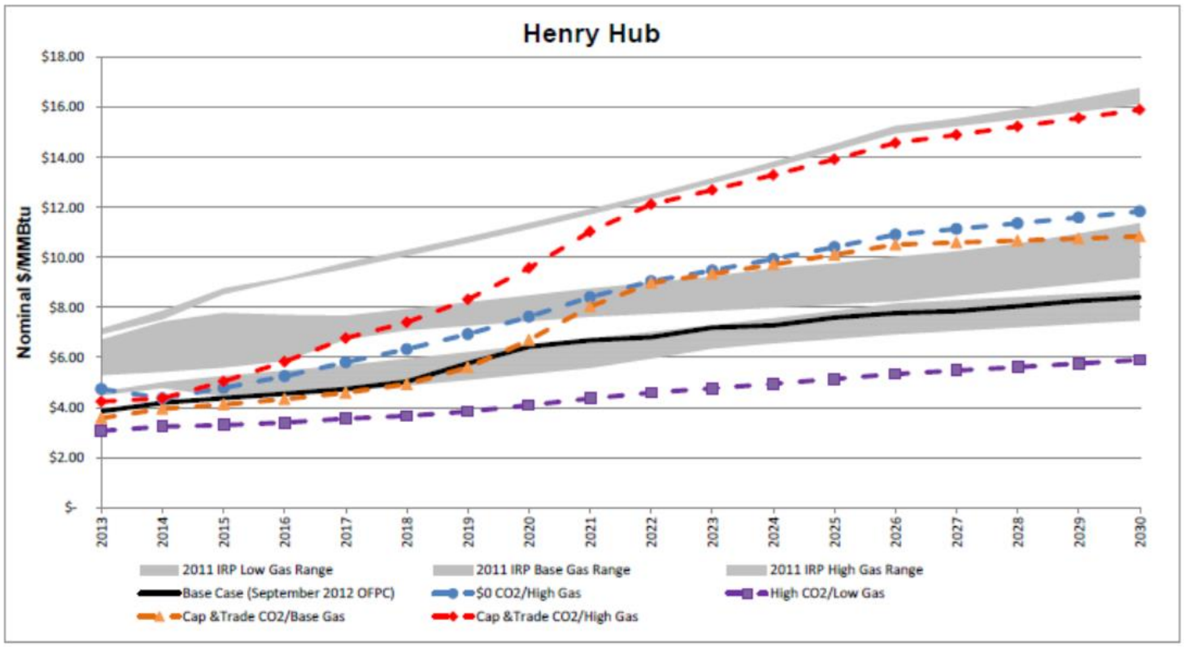
Year	Annual Sept 2012 OFPC ($/MWH)	Annual w/ 25% Price Increase starting 2015 ($/ MWH)	Annual Percent Increase
2013	$29.19	$29.19	0.0%
2014	$29.27	$29.28	0.0%
2015	$32.54	$37.73	16.0%
2016	$31.51	$38.43	21.9%
2017	$35.57	$42.76	20.2%
2018	$36.94	$44.82	21.3%
2019	$39.42	$49.22	24.9%
2020	$45.99	$55.25	20.1%
2021	$46.48	$57.26	23.2%
2022	$52.34	$65.74	25.6%
2023	$56.16	$70.13	24.9%
2024	$59.10	$72.71	23.0%
2025	$55.53	$71.06	28.0%
2026	$58.89	$73.80	25.3%
2027	$59.46	$74.52	25.3%
2028	$61.48	$77.77	26.5%
2029	$59.68	$75.67	26.8%
2030	$60.11	$77.72	29.3%
2031	$62.31	$80.50	29.2%
2032	$65.92	$84.25	27.8%

20-Year Levelized Prices (Nominal) @ 7.154% Discount Rate

$/MWh	**$43.11**	**$53.55**	**24.21%**

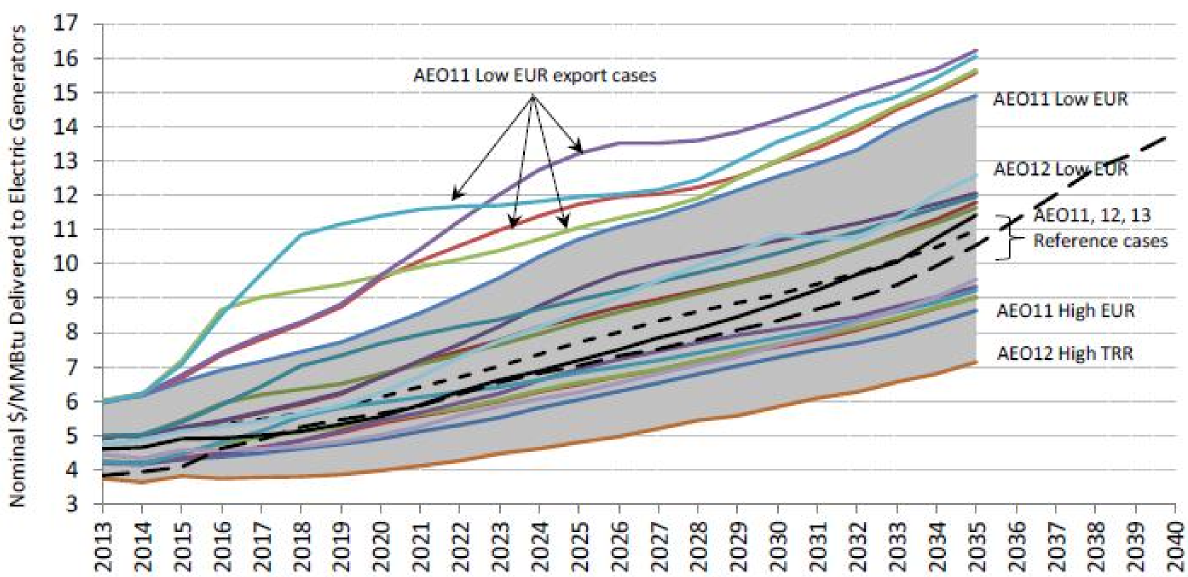
Figure 4

Comparison of Natural Gas Prices: 2011 IRP vs. 2013 IRP



[redacted] December 19, 2012 [redacted]

Figure 5



Source: EIA 2012a, EIA 2012b, EIA 2012c, EIA 2011

Figure 7. Projected Natural Gas Prices Delivered to Electricity Generators, Total U.S.

Q: How do you recommend that the Proxy/PDDRR method be modified to account for the avoided cost of fuel volatility and hedging costs?

A: A possible method would be to use the Company's averaged hedging costs over a twenty year period, since this is generally the length of time a renewable energy PPA. The average hedging costs could be translated to a cost per MMBTU and then MMBTUs converted to MWHs and included in the calculation of the energy portion of the avoided cost on a $/MWH basis. This method would reflect the actual costs that the non-fuel based renewable energy project brings to the system. The method may not capture the extreme fuel and energy price costs to ratepayers that occurred in the early 2000 time period.

<u>Integration costs</u>

Q: What does the Company propose with regard to renewable energy integration costs?

A: The Company proposes to utilize the same method it uses in the IRP to calculate wind integration costs, but seems to indicate that it will use its 2010 wind integration study rather than the more current study (which involved a technical review committee). The Company also proposes to use its wind integration costs as "a proxy for integrating solar at this time." (Direct Testimony of Gregory N. Duvall, lines 448-49)

Q: What is your response to this recommendation?

A: I recommend that the Company use its more current wind integration study to determine wind integration costs. Additionally, I recommend that solar and other renewable resources not incur an integration charge. Geothermal is a stable base load resource and the penetration of utility scale solar in PacifiCorp's system is so small that the integration costs are negligible.

ISSUE 3: OWNERSHIP OF RECS FROM RENEWABLE QFS UNDER THE PROXY/PDDRR METHOD, INCLUDING THE RIGHT OF A QF TO BUY BACK RECS (AND THE ASSOCIATED PRICE):

Q. What is the Company's position with regard to ownership of RECs from QF projects?

A. The Company, in the testimony of Paul Clements, argues that it should be entitled to any RECs associated with renewable QF energy production. Mr. Clements reasons as follows: because renewable QFs must be fueled predominately by renewable energy, if the Company does not get the renewable energy attributes associated with QF electricity generation, then the Company is not receiving the characteristic that enabled the facility to be designated as a QF in the first place.

Q. Do you agree with this reasoning?

A. No. I disagree with this for several reasons: 1) it conflates federal requirements with state policy objectives, 2) it is inconsistent with FERC precedent, and 3) it discriminates against renewable QFs, contrary to PURPA.

First, The Company is not, as a matter of PURPA (a federal law), entitled to RECs (state creations) associated with renewable QF electricity generation. PURPA was enacted in 1978, before the concept of energy-separable renewable energy attributes was created. PURPA is a federal statute, but RECs are creations of state policy objectives. States determine what resources are able to generate RECs and for what policy ends (for example, encouraging renewable energy development and resource diversification through renewable portfolio standards). Utah has a statute that outlines what resources are able to generate RECs for purposes of complying with Utah's renewable portfolio standard. Utah-based RECs sold into other states must comply with purchasing states' renewable portfolio standards. These requirements are independent of PURPA, and PURPA's requirements are independent of state REC laws.

Similarly, Mr. Clements' assertion that PURPA *requires* that utilities retain RECs associated with renewable QF development is wrong. FERC has consistently found:

> [C]ontracts for the sale of QF capacity and energy entered into pursuant to PURPA do not convey RECs to the purchasing utility (absent an express provision in a contract to the contrary). While a state may decide that a sale of power at wholesale automatically transfers ownership of the state-created RECs, that requirement must find its authority in state law, not PURPA.[29]

FERC has clearly explained that an automatic transfer of RECs from renewable QF generation would have to be authorized at the state level, not through PURPA.

Finally, granting RECs to the utility, as under the Company's proposal, would disadvantage renewable QFs compared to other QFs, contrary to PURPA. RECs have value and are sold and retired for compliance with renewable portfolio standards or for voluntary markets. Therefore, given the same price per MWh, a renewable QF that generates RECs that are then transferred to a utility would be paid less for energy and capacity than a cogeneration QF because the price paid per MWh to the renewable QF acquires RECs in addition to energy and capacity. This type of discrimination is prohibited by PURPA.

[29] *Am. Ref-Fuel Co., Covanta Energy Group, Montenay Power Corp., & Wheelabrator Technologies Inc.*, 105 FERC ¶ 61,004 (2003), *request for rehearing denied*, 107 FERC ¶ 61,016 (2004).

In summary, the Company's arguments in support of its acquiring ownership of RECs without paying for them are unsupportable.

Q. The Company also proposes that QFs not be allowed to buy back any RECs contractually conveyed to the utility. How do you respond?

A. Under the current wind-specific pricing method RECs are transferred to the utility, but renewable QFs have the option of buying back any RECs at the REC price designated in the Company's IRP. Given that the Company currently designates a zero dollar value for RECs, it is unsurprising that they do not want renewable QFs to exercise their right to buy back RECs for free.

Q. The Company says "The Company's IRPs no longer calculate a specific direct value for RECs in dollars per MWH, but instead determine a preferred portfolio based on resource needs and compliance obligations. Therefore, a dollar per MWh REC value from the IRP does not exist and thus can no longer be used as contemplated in the 2005 Order." Is this different from designating a zero dollar value to RECs?

A. No, it isn't. Not assigning RECs a specific value in the IRP is the same as giving them zero value. RECs do have value, however.

Q. What is Utah Clean Energy's recommendation regarding REC ownership under Schedule 38?

A. The Commission should not grant RECs to the utility automatically through avoided cost pricing under PURPA. The Company is proposing to calculate avoided costs in a way that does not recognize any of the renewable attributes of renewable QFs; therefore to convey the value of those attributes without compensation to the QF would be discriminatory and inconsistent with PURPA and FERC precedent. REC value, based on a QF's renewable energy attributes, exists apart from the energy and capacity paid for through avoided cost rates.

Q. How is renewable energy attribute defined in Utah's carbon reduction statute?

A. Utah Code Title 54 Chapter 17, Part 6 is Utah's carbon emissions reduction statute. Renewable energy attributes are not defined therein (though the statute designates what sources are renewable). The statute allows the Commission to utilize "a regional system or trading program" to recognize renewable energy certificates, including the Western Renewable Energy Generation Information System (WREGIS). The WREGIS definition, which follows, excludes energy, capacity, reliability, and other power attributes from the definition of renewable energy attributes:

> Renewable and Environmental Attributes: Any and all credits, benefits, emissions reductions, offsets and allowances, howsoever entitled, attributable to the generation from the Generating Unit, and its avoided emission of pollutants. Renewable and Environmental Attributes do not include (i) any energy, capacity, reliability or other power attributes from the Generating Unit, (ii) production tax credits associated with the construction or operation of the Generating Unit and other financial incentives in the form of credits, reductions or allowances associated with the Generating Unit that are applicable to a state, provincial or federal income taxation obligation, (iii) fuel-related subsidies or "tipping fees" that may be paid to the seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular preexisting pollutants or the promotion of local environmental benefits, or (iv) emission reduction credits encumbered or used by the Generating Unit for compliance with local, state, provincial or federal operating and/or air quality permits.[30]

[30] *WREGIS Operating Rules*, WECC (December 2010), available at: http://www.wecc.biz/WREGIS/Documents/WREGIS%20Operating%20Rules.pdf.

Q. How are renewable energy attributes different from risk mitigation such that they should be valued distinctly?

A. REC value exists beyond avoidable fuel price risk and hedging costs that I discuss above. And as described above, renewable QFs can alleviate costs associated with adapting to a changing climate. For example, renewable QFs utilize much less water than conventional resources and will therefore be less susceptible to reduced water supply or increased water temperatures. Furthermore, renewable resources do not emit greenhouse gas emissions that contribute to climate impacts. Therefore, unless the Company pays a QF for the renewable energy attributes associated with its energy production, the QF should be able to keep the RECs associated with those attributes.

CONCLUSION

Q. Please summarize your recommendation regarding renewable QF avoided cost pricing?

A. Utilities, utility planners, utility regulators, and ratepayers are facing great uncertainty with respect to the implications and impacts of utility resource decisions. There are significant costs and risks associated heavy reliance on fossil-fueled resources and front office transactions that should be accounted for in avoided cost electricity prices. Furthermore, ratepayers are not only at risk for fuel volatility cost and regulatory costs, they are also on the hook as citizens and taxpayers for costs associated with climate change, including the increasing costs of droughts, fires, and extreme weather events. Appropriately pricing electricity from renewable energy QFs would encourage development of resources that can mitigate the costs and risks associated with traditional electricity generation and its impacts, ultimately benefitting ratepayers. Avoided cost pricing should appropriately value the capacity value of renewable QFs and include actually avoidable costs, based on the risk profile and cost impacts of its resource procurement decisions. I recommend use of the Market Proxy method when the Company's integrated resource plan selects renewable resources and a Proxy/PDDRR method with the modifications that I recommend above when the IRP does not select renewable resources.

Q: Does that conclude your testimony?

A: Yes, it does.