

UM 1734/PacifiCorp
September 23, 2015
Sierra Club Data Request 1.6

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In the past year, has PacifiCorp or any of its parent companies appeared before any congressional committee to recommend any amendments or modifications to PURPA? Please identify those actions and provide any written comments.

Response to Sierra Club Data Request 1.6

Yes. Jonathan Weisgall, Vice President, Legislative and Regulatory Affairs, Berkshire Hathaway Energy, made two congressional committee appearances: (1) the Senate Energy and Natural Resources Committee on May 14, 2015 and, (2) the House Energy and Commerce Subcommittee on Energy and Power on June 4, 2015. Please refer to Attachment Sierra Club 1.6.

**STATEMENT OF JONATHAN M. WEISGALL
VICE PRESIDENT, LEGISLATIVE AND REGULATORY AFFAIRS
BERKSHIRE HATHAWAY ENERGY
BEFORE THE SENATE ENERGY AND NATURAL RESOURCES COMMITTEE
May 14, 2015**

Introduction

Chairman Murkowski, Ranking Member Cantwell, and members of the Committee, thank you for the opportunity to appear before you today as you consider legislation to address challenges and opportunities to modernize U.S. energy infrastructure. My name is Jonathan Weisgall, and I am vice president for legislative and regulatory affairs at Berkshire Hathaway Energy. With our roots in renewable energy, BHE today owns three regulated U.S. utilities – MidAmerican Energy Company, PacifiCorp, and NV Energy – with customers in 11 states as well as other energy assets in the U.S., Canada, the U.K., and the Philippines – that collectively deliver affordable, safe, and reliable service each day to more than 11.5 million electric and gas customers and consistently rank high among energy companies in customer satisfaction.

A large part of our U.S. business strategy has been to invest in renewable energy and develop competitive transmission projects to meet electric reliability needs and existing and emerging clean energy goals. When current projects are completed, we will have invested approximately \$8.0 billion in our wind energy portfolio among our regulated utilities in Iowa, Wyoming, Oregon, and Washington State. In addition, we have invested an additional \$8.1 billion in just the last five years through our unregulated subsidiary, BHE Renewables, in three very large utility-scale solar projects as well as wind projects. And we continue to operate our 10 geothermal plants, some of which date back to the 1980s. In order to encourage the continued development of renewable energy resources at low costs to our customers and protect them from volatility in power costs, we have identified three areas that would benefit from Congressional action.

First, modernize the Public Utility Regulatory Policies Act of 1978, also known as “PURPA.”

I. PURPA Background – Need for Change

The Public Utility Regulatory Policies Act of 1978 (PURPA) was enacted to increase the country’s energy independence, decrease reliance on foreign oil, and reduce dependence on fossil fuels by promoting increased energy efficiency. Section 210 directed the Federal Energy Regulatory Commission (FERC) to prescribe rules necessary to encourage cogeneration and small power production. Qualifying facilities (QFs) include cogeneration plants that use steam or heat generated from an industrial or commercial process to also produce electricity, and small power production facilities that are not more than 80 megawatts (MW) in size and use solar, wind, biomass, waste, or other renewable resources to produce electricity. Section 210 required

FERC to develop rules requiring utilities to purchase power from QFs, also known as the mandatory purchase obligation.

Current PURPA Provisions are Costly for Utility Consumers

Since 1978, PURPA has helped reduce U.S. dependence on fossil fuels by promoting energy efficiency and renewable resources. Renewable generation in the U.S. has increased significantly since PURPA's passage, substantially due to financial incentives in the tax code, state renewable portfolio standard requirements, stricter Environmental Protection Agency air emission regulations, and technological improvements. The continuation of the mandatory purchase obligation as it exists today, however, is imposing significant and unnecessary costs on consumers:

In many instances, the power produced by QFs is not needed to replace baseload generation or meet decreasing levels of demand.

Growth of electricity demand has slowed in each decade since the 1950s. Since PURPA's enactment, electricity markets have developed to allow utilities to purchase replacement power rather than build baseload plants. BHE's PacifiCorp utility is experiencing a significant increase in PURPA contract requests, despite the fact that its long-range resource plan shows no need for additional generation resources until 2028. It currently has requests for 3,641 MW of new PURPA contracts, in addition to the 1,732 MW of PURPA contracts that are already executed. The number of PURPA contracts may soon equal PacifiCorp's average retail load. For example, the 5,373 MW of existing and proposed PURPA contracts at their nameplate capacity would be equal to 79% of PacifiCorp's average retail load and 108% of PacifiCorp's minimum retail load.

State administrative decisions regarding long-term power purchase contracts have tended to over-estimate future market prices.

The mandatory purchase obligation requires QFs to sell to the interconnected local utility at a set price based on the utility's "avoided cost," regardless of whether the utility needs the generation or whether it is the most efficient resource choice. Avoided cost is the cost the utility would have incurred to produce or purchase the power elsewhere. Although avoided cost rates are theoretically intended to reflect actual costs to build or replace necessary generation to protect customers from paying other costs, in practice state "administrative" determinations, particularly for the long-term power purchase contracts that their vertically integrated utilities have typically been required to enter into to facilitate QF construction, have tended to over-estimate future market prices. These contracts, with up to 20-year terms, often assumed electric rates would continue to rise, an error that has required utility ratepayers to pay substantially above-market rates for power, even in instances where a utility's integrated or long-term planning process demonstrates that no new resources are needed for the foreseeable future. Left unchecked, the resulting subsidies will continue to unfairly shift these rising power costs to utility customers and undermine competitive wholesale electricity markets.

Long-term fixed-price contracts carry significant risk. For example, on August 1, 2014, a 10-year fixed-price contract for a 7-day by 24-hour electricity product at the Mid-Columbia

("Mid-C") wholesale power market trading hub was priced at \$45.87 per megawatt-hour (MWh). On February 2, 2015, just six months later, that same 10-year contract was priced at \$38.11 per MWh. The 10-year electricity market declined 17% in just six months. Over the next 10 years, PacifiCorp is under contract to purchase 38.9 million MWhs under its PURPA contract obligations at an average price of \$66.32 per MWh. The average forward price curve for Mid-C during this same 10-year period is \$38.11 per MWh, or a difference of \$28.21 per MWh. Thus, the market price is 43% lower than the PURPA contract obligation price that PacifiCorp is forced to pay for this unneeded power. This means that PURPA-mandated power purchases – which our customers don't need – could cost PacifiCorp's customers an incremental \$1.1 billion for the next 10 years above market prices. And PacifiCorp's experiences are far from isolated; many Western utilities are facing similar PURPA contracts.

PURPA contracts are not subject to the same planning and cost scrutiny as other resource decisions and thus expose customers to increased and unnecessary risks.

Many utilities, as required by state commissions, utilize an integrated resource planning (IRP) process to evaluate proposed energy contracts to ensure that any resource decisions are reasonable and prudent. The planning horizon for such resource plans typically is in the three-year range. PacifiCorp, for example, primarily enters into long-term transactions (those that exceed 36 months) only when there is a clearly identified long-term resource need in its IRP. Companies also utilize a rigorous request for proposal (RFP) process to acquire any long-term transaction or resource need identified in the IRP. Under PURPA, however, companies cannot refuse to execute PURPA contracts based on the price or the contract term, or whether the energy is needed, or based on other transaction parameters that would normally be the basis for rejection of other RFP contracts.

PURPA contracts do not go through the same competitive bid RFP process, including oversight by an independent evaluator to ensure they are lowest cost. PURPA contract executions are not limited to the size of the resource need in the IRP. PURPA contracts do not receive the same upper management review and analysis because upper management does not have the discretion to refuse the mandatory purchase obligation under federal law.

The mandatory purchase obligation can cause operating inefficiencies and reliability issues on the host utility systems.

PURPA contracts can cause operating inefficiencies and reliability issues for the host utility, which has no control over where the QFs are sited or integrated into its system. Many QFs are "undispatchable" and might lead to over-generation conditions or inefficient use of baseload units that are forced to cut back operations to accommodate unscheduled QF purchases. Inefficient siting of large amounts of QF power can increase the need for otherwise unneeded transmission upgrades.

Open Access and Market Formation

Since 1978, substantial changes in the electric industry have removed the structural barriers to entry and opened up opportunities for new entrants, including QFs, to supply wholesale energy. FERC has imposed open access transmission tariff requirements and

standardized interconnection rules for small generators (20 MW or less) and large generators (greater than 20 MW). Thus, generators of all sizes have the right to interconnect to the local utility under a FERC-approved set of interconnection and transmission rules that apply to all generators on a non-discriminatory basis.

The industry has seen the formation of independently administered regional markets across the country for power producers to bid to supply energy, in day-ahead or real-time. Today, there are six regional markets now run by independent system operators (ISOs) and regional transmission organizations (RTOs), who also administer open access transmission tariffs that facilitate the availability of transmission and interconnection services to the grid for all entrants.

Energy Policy Act of 2005 (EPAct 2005)

In 2005, Congress recognized that these structural changes had reduced existing barriers to entry for QFs and that the mandatory purchase obligation, which imposed significant costs to consumers, was no longer necessary. Congress adopted Section 1253 of the EPAct 2005, adding Section 210(m) to PURPA, which provides for the termination of a utility's obligation to purchase power from QFs in its service territory after appropriate findings from FERC that a QF has nondiscriminatory access to one of three specified categories of wholesale markets. The three categories of markets under Section 210(m)(1) include:

- (A) "Day 2 markets" (independently administered, auction-based day-ahead and real-time markets for the sale of electric energy and wholesale markets for long-term sales of capacity and electric energy);
- (B) "Day 1 markets" (transmission and interconnection services that are provided by a FERC-approved regional transmission entity and administered pursuant to an open-access transmission tariff that affords nondiscriminatory treatment to all customers, and competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the QF is interconnected); and
- (C) "Comparable markets" (for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as the two "Day 2" and "Day 1" markets described above).

FERC's Implementation of EPAct 2005

In 2006, FERC issued new rules to implement the new Section 210(m) to govern the removal of the mandatory purchase obligation. In Order No. 688 (and subsequent orders), FERC created a rebuttable presumption that QFs larger than 20 MW have nondiscriminatory access in the "Day 2 markets" of the then-Midwest (now Midcontinent) ISO, PJM, ISO New England, and New York ISO; in the "Day 1 markets" of Southwest Power Pool; and the "comparable markets" of the California ISO (CAISO) and the Electric Reliability Council of Texas (ERCOT). FERC allows QFs larger than 20 MW to rebut the presumption by showing they have no access due to

operational characteristics or transmission constraints. The evidentiary showings FERC established are higher for “Day 1 markets” than for “Day 2 markets” and highest for “comparable markets” due to the presumption that QFs there have fewer off-system sales opportunities respectively in these markets. FERC also established a rebuttable presumption that QFs smaller than 20 MW lack nondiscriminatory access to the three 210(m) markets unless a utility makes a facility-specific showing that each small QF has access. This presumption has made it exceedingly difficult for utilities to avoid purchasing from QFs, which could be as large as 20 MW, without limit, and regardless of whether the power is needed.

In applying Order No. 688, FERC has routinely terminated the mandatory purchase obligation from QFs greater than 20 MW in organized “Day 2 markets,” but, with limited exceptions, denied the same relief with respect to small QFs. FERC has thus far not terminated the mandatory purchase obligation for any utility operating outside an organized market and, other than ERCOT and CAISO, has not found any “comparable markets” to exist. Only utilities that have transferred control over their transmission systems to a FERC-approved ISO/RTO have satisfied FERC’s market structure termination criteria. While FERC has continued to encourage utilities to join ISO/RTOs, participation remains voluntary. Thus, there has been no relief from the mandatory purchase obligation for utilities that have determined that joining an ISO/RTO is not in the best interest of their customers.

II. Suggested Legislative Reforms

As detailed above, PURPA – and FERC’s implementing regulations – have not kept pace with wholesale market evolutionary changes. Developments such as new energy imbalance market structures as well as FERC’s imposition of standardized interconnection rules and procedures tailored for smaller facilities have effectively removed any remaining structural barriers to entry and opened up opportunities for new entrants, including QFs, to supply wholesale energy to distant markets whether the host utility is in an ISO/RTO or not. BHE and our trade association, the Edison Electric Institute, believe that PURPA needs to be modernized to recognize these changes and protect a broader group of utility customers from unnecessary costs and inefficiencies.

Toward that end, BHE has proposed a legislative suggestion for modernizing PURPA and removing its harmful elements for utility customers, while recognizing the changed circumstances facing QFs today since the EPAct 2005 Section 210(m) provisions were adopted (*See* Attachment A - Text of Proposed PURPA Modernization Legislation). As outlined below, these statutory changes ensure that utility customers are not harmed by unnecessary purchases of QF power and promote further regional wholesale market development by updating PURPA to recognize the vast new opportunities that QFs of all sizes have today to compete in wholesale electric markets and utility competitive solicitations for both short-term and long-term energy and capacity sales. BHE’s proposed PURPA modernization amendment has three main elements:

- (1) Expand “comparable markets” under Section 210(m)(1)(C). The proposed amendment revises the “comparable markets” section to specifically include voluntary, auction-based energy imbalance markets as the type of markets that meet the threshold market

requirement in the existing law, so that utilities participating in those markets are relieved of PURPA's mandatory purchase obligation.

This change would update the statute to recognize the vast new opportunities that QFs of all sizes have today to compete in wholesale electric markets for both short-term and long-term energy sales. This includes the voluntary, 5-minute Western EIM that CAISO and PacifiCorp launched in November 2014, which currently includes portions of California, Idaho, Oregon, Utah, Washington, and Wyoming and will soon add much of Nevada when our NV Energy utility joins the EIM in October 2014. The independently administered EIM now provides a broader range of QFs a meaningful opportunity to sell electric energy, including short-term energy sales, to buyers other than their interconnecting electric utility, and provides access to a real-time wholesale market of comparable competitive quality as a "Day 2 market."

By including energy imbalance markets, such as the Western EIM, in the type of markets that meet the comparable markets standard, the proposed amendment will encourage the expansion of the EIM by attracting additional utility participants and new buyers and sellers. Such expansion will yield even further expanded market opportunities for QFs and even greater savings for customers, more efficient deployment of intermittent renewable energy resources, and enhanced operational and reliability benefits for the Western grid. The amendment also recognizes that eligibility for termination of a utility's QF purchase obligation under PURPA should not be effectively tied to that utility joining an ISO/RTO as a participating transmission owner, when doing so may not be in the best interest of its customers.

- (2) Eliminate the 20-MW size demarcation for presumption of access to markets. The proposed amendment makes clear that QFs of any size are presumed to meet the access requirement to the relevant markets, if the QFs are eligible for service under FERC-approved Open Access Transmission Tariff and interconnection rules in the relevant market and the QF is able to participate in competitive solicitations overseen by a state regulatory authority.

Order No. 688 drew the line between large and small QFs in 2006 based on the circumstances existing at that time. Today, with the creation of FERC-mandated standardized interconnection rules and procedures tailored for smaller facilities, open-access transmission and market access is available to small and large QFs and FERC's existing size distinction is no longer warranted. Eliminating the existing 20-MW size threshold would benefit utility customers, as they are harmed by unnecessary purchases of QF power regardless of whether those purchases are from multiple smaller QFs or a single larger QF. Updating the statute also recognizes the meaningful opportunities QFs of all sizes now have today to sell capacity, including long-term and short-term sales, and electric energy, including long-term and short-term sales, to buyers other than their interconnecting electric utility to the extent QFs can participate in competitive solicitations overseen by a state regulatory authority. Today, such processes are increasingly being used to allow QFs and other independent producers to compete with the incumbent utility to supply capacity and energy needed by the utility consistent with its state-sanctioned IRP process. Such competitive solicitations provide QFs access to a wholesale market of comparable competitive quality as a "Day 2 market."

- (3) Requires FERC to revise its regulations. The proposed amendment directs FERC to revise its regulations, such as Order No. 688, within 120 days to incorporate the changes.

Finally, BHE urges Congress to consider these and other PURPA modernization proposals offering relief to utilities from the current mandatory purchase obligation that we and our trade association, the Edison Electric Institute, support. Examples include S. 1037, which would tie termination of the purchase obligation to a state determination that additional generation resources are not needed, or proposals to create a rebuttable presumption targeting PURPA gaming created by FERC's "one mile" rule. Our utilities commonly see larger projects divided into smaller QF projects to game the "one mile" rule and capture higher PURPA prices at the expense of customers.

A second area benefiting from Congressional action is improving the federal transmission permitting, siting, and review processes.

As the largest transmission owner in the Western U.S. and an active developer of several high-voltage transmission projects spanning multiple states and federal lands, BHE has long supported measures to better coordinate the existing federal permitting and siting processes for major electric transmission projects on public lands to reduce the uncertainty for project applicants and to streamline the approval process. Reforming current federal permitting and siting processes is one of the Edison Electric Institute's top priorities in federal energy legislation.

Additionally, as part of its ongoing effort to permit and site its multi-state Energy Gateway transmission project, among the nation's largest currently in development, our PacifiCorp utility has first-hand experience participating in the Administration's Interagency Rapid Response Team for Transmission (RRTT), and most recently, outreach sessions as part of the Administration's Quadrennial Energy Review development process. BHE offers the following observations and legislative recommendations with the above experiences and perspectives in mind.

First, undue delays in obtaining federal regulatory permits only serve to postpone the construction of needed transmission projects and the clean energy, reliability and other benefits such projects provide for customers. In order to continue developing America's vast renewable energy resources and delivering them to customers, and maintaining an efficient and reliable electric grid, completing such transmission projects on a timely basis will be essential. Without PacifiCorp's Energy Gateway and other regional transmission projects on public lands, there will be no means to transport adjacent renewable generation to distant load centers. As a result, some of our nation's largest and best clean energy resources will remain unable to contribute as they wait for transmission lines to be sited and built. The most critical path item to achieving this objective is schedule predictability within the federal permitting process. We believe substantial process improvements, once realized, will deliver significant benefits to the nation's utility customers who depend upon adequate, reliable, and reasonably-priced electricity to carry on their daily business, and will support vital economic growth across the country. The greatest

efficiencies to be gained are through better National Environmental Policy Act (NEPA) execution and, accordingly, BHE recommends that Congress focus on improving that part of the federal permitting and siting process.

Second, BHE appreciates that Congress sought to improve the federal transmission siting process in 2005 when it added new Section 216(h) to the Federal Power Act giving the Department of Energy (DOE) new lead agency authority to coordinate the approval of all required federal authorizations and related environmental reviews for transmission projects on public lands. While it has been helpful to have a lead coordinating agency, DOE's performance frankly has not met industry expectations, nor is it producing the positive impacts envisioned by Congress. Fairly or not, DOE's critical 216(h) responsibility has simply been eclipsed by other departmental priorities. Importantly, the lone rulemaking Congress charged DOE with promulgating under 216(h) role was originally proposed in 2008, revised again in 2011, and has still yet to be finalized, and the DOE position to implement 216(h) has been vacant for over 18 months. Given DOE's track record and the successful role FERC continues to play as the lead agency responsible for permitting and siting interstate natural gas pipelines, BHE continues to support transferring the DOE's Section 216(h) lead agency coordinating authority to FERC, which we believe would better ensure that comparable electric transmission projects are permitted in a synchronized and timely manner.

Third, BHE similarly appreciates the continuing efforts of DOE and the RRTT in developing streamlined and coordinated approaches to the permitting and siting of transmission projects on federal lands. The Administration's related RRTT reform effort, launched by DOE in October 2011 with the targeting of seven national priority transmission lines, including PacifiCorp's Gateway West project, was unquestionably a step in the right direction. Unfortunately, in the eyes of PacifiCorp and other project sponsors, the RRTT process, too, has fallen short of expectations, producing precious few success stories to date beyond improving the coordination among the federal agencies involved in project NEPA analysis. By all accounts the RRTT has not measurably accelerated the permitting of any lines or moved projects' NEPA process any faster, let alone provide project proponents the schedule predictability they desire more than anything. To a company, project sponsors have been hard pressed to point to direct, positive ways in which the RRTT solved specific organizational accountability and other problems, let alone accelerated their project timelines.

Fourth, against the backdrop above, to meet national policy goals, BHE and the Edison Electric Institute both encourage Congress to intervene again and ensure that the efficiency and effectiveness of multiple agency reviews and decisions on major transmission projects is improved, and the uncertainty with federal cooperating agency reviews is reduced so that needed transmission expansion can keep pace with the nation's revolving resource mix that is being driven by a rapidly changing policy landscape. Congress should take steps now to ensure that the federal RRTT agencies provide the schedule certainty lacking today and assign clear accountability within the cooperating agencies to deliver NEPA milestones on reasonable fixed timeframes. Similar measures are needed to ensure that national energy policies are infused into staff-level decisions and federal agency management must create feedback loops to obtain confidence that field staff is implementing their duties in light of current policies. Each of these recommendations, if adopted, would have the salutary effect of facilitating the timely release of

critical environmental review documents and mitigating the permit schedule uncertainties facing project sponsors by averting the potential for conflicting federal policy objectives.

Based on our PacifiCorp utility's experience trying to site and permit its multi-state Gateway West transmission project, the more time the Bureau of Land Management (BLM) takes to resolve route controversy on private and federal lands, the more apt the agency is to adopt alternative routes for inclusion in the Environmental Impact Statement (EIS), delaying a project, which in this instance is critical to the development of additional renewable energy resources in various Western states. In fact, delays continue today, seven years after the Gateway West Public Scoping. For the project's final two segments, the BLM has initiated an additional two-year supplemental EIS process to look at even more alternative routes, meaning PacifiCorp may not receive a Record of Decision (ROD) until sometime in 2016, nearly 10 years after it filed an application with the BLM for an easement across federal lands. This is unacceptable.

Further, by taking more time, not only do more alternatives come into play, but the federal agencies are continually adopting/developing/changing policies, manuals, and instructions that require additional analysis and create new compensatory mitigation requirements for projects that have been in permitting for many years. These projects don't get "grandfathered." This is occurring on PacifiCorp's Gateway South project with regards to sage grouse, lands with wilderness characteristics, and new conservation easements funded by the Natural Resource Conservation Service – U.S. Department of Agriculture.

Above all, federal agencies must be required to truly work together to assure consistent application of permitting requirements and clear communication of requirements between field/state/federal agency headquarter levels prior to the start of the permitting process and throughout the process. PacifiCorp's experience has been that the above structure has worked fairly well where it has been implemented, *e.g.*, on PacifiCorp's Sigurd-to-Red Butte segment. This practice needs to be made a federal priority so the benefits can be more broadly realized. BHE believes it is reasonable for the federal lead agency to complete the NEPA process from right-of-way (ROW) application to the ROD and the ROW grant within three to four years. Schedule certainty is as critical if not more important than any actual benchmark.

Finally, as this Committee considers key elements of a comprehensive, bipartisan energy package, BHE would hope you put further federal coordination around transmission permitting and siting on the list as a top priority, with the goal of assuring consistent and expedited treatment of transmission projects requiring interagency and intergovernmental coordination. We strongly support enhancing FERC's statutory role in facilitating improved federal permitting processes. As an independent federal agency charged by Congress with promoting the development of safe, reliable, secure, and efficient energy infrastructure, we believe FERC could bring a fresh perspective and critical focus to boost the other RRTT agencies' abilities to dramatically improve the overall quality and timeliness of their existing federal permitting processes. We were pleased to see that two legislative proposals have been offered to that end. In the event Congress opts not to adopt the approach suggested by Sen. Heinrich (D-NM) in S. 1017, which would fully transfer DOE's Section 216(h) authority directly to FERC, we'd support enactment of Chairman Murkowski's own approach, S. 1217, which would enshrine the RRTT in law and create a Transmission Ombudsperson within FERC to help address interagency

issues or delays on permits and complaints from parties involved in electric transmission infrastructure permit applications. Either approach would be a marked improvement of the current state of affairs.

The third area benefiting from Congressional action is encouraging States to minimize cost-shifting among customers.

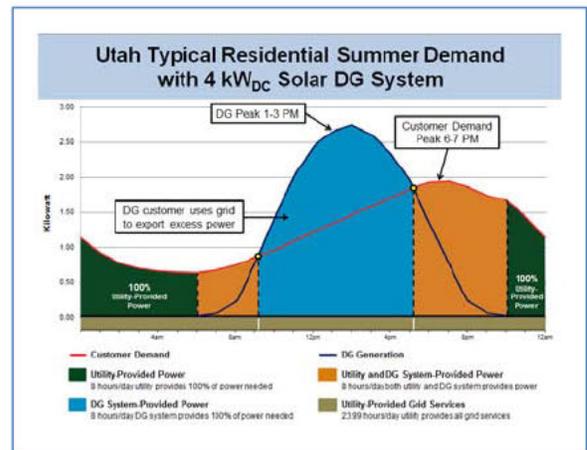
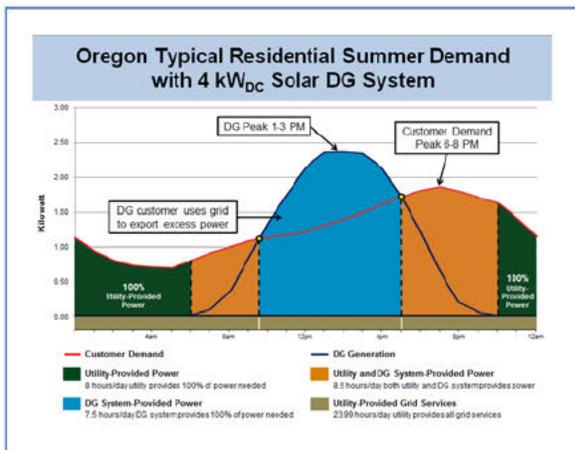
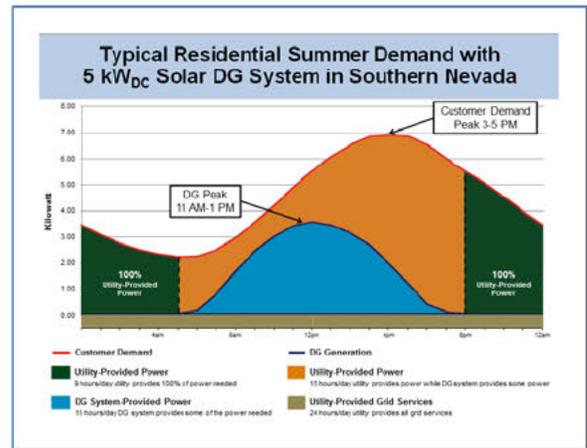
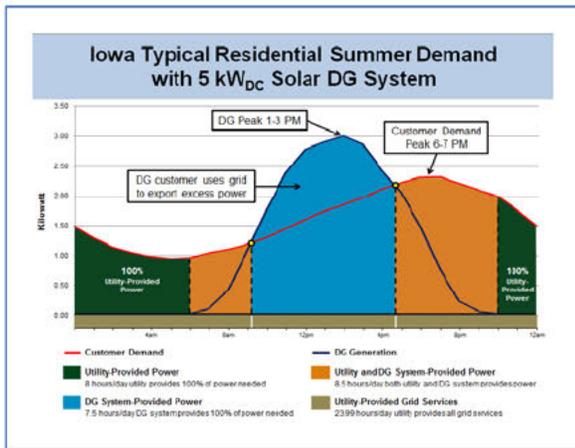
After a significant period of relative stability, the energy industry is evolving rapidly. New issues like distributed generation, electric vehicles, smart grid, energy storage, advancements in wind and solar technology, flat load growth and increasing environmental regulation, necessitate changes in the way we do business. We are positioning our company to be sustainable in this changing energy marketplace and changing the ways we do business to provide better value for our customers.

A Different Type of Customer, But Still Dependent on the Grid

A growing number of our customers, both commercial and residential, are interested in generating their own power, through the installation of distributed generation. It's our responsibility to help our customers understand this option, because nearly all of the distributed generation customers will still be connected to our utilities' electrical grid. When their distributed generation systems generate more power than they need, they need the electrical grid to distribute the excess power. And, when their distributed generation systems aren't generating power – for example with a rooftop solar system, when the sun sets – they will still rely on the utility to provide them with power services. They rely upon the grid all the time for reliability, for example, using the grid to help start air conditioners, refrigerators and motors even when they produce their own power.

As distributed generation becomes an option for more consumers, three important things must be considered. First, distributed generation can be costly in comparison to utility scale generation. For example, although the cost of solar power has been declining steadily, the cost of utility scale solar continues to be about half of the cost of distributed solar. This is due largely to economies of scale. It is less costly to install one 4 MW unit than 1,000 4Kw units. All customers can benefit from utility scale solar and these systems can be integrated into utility control and dispatch processes.

Second, today's distributed generation systems cannot function without the grid, nor can they fully meet the customer's electricity needs. For example, in the case of rooftop solar the following graphs illustrate the customer demand for electricity in different states over the course of a typical summer day (red line) and the power being generated by a rooftop solar distributed generation system (dark blue line). The orange shaded area shows the number of hours during the day the utility and the distributed generation system provide power. The blue shaded area shows the hours during the day when the distributed generation system provides for the residential customer's power needs, and during some hours produces excess power that is distributed by the utility.



Third, utility grid services are needed 99.99% of the time to ensure power needs are met reliably and safely. The tan-shaded area along the bottom of each graph shows the utility provides all grid services 23.99 hours a day. Power is delivered through the utility's system to distributed generation customers on cloudy days, at night, when the customer's system is not functioning properly, and even on hot, sunny days when solar panels may not meet all of the residential customer's power needs.

Distributed Generation Customers Still Need the Grid's Instantaneous, Start-Up Power

It will almost never be true that the power produced by distributed generation customers' system will exactly match their power needs. At any time, grid services are needed to meet the customer's power needs or to transport excess power to the utility. Startup of some appliance motor loads (e.g., air conditioner, refrigerator, washing machine) requires supplemental power beyond what a distributed generation system can provide. For example, when a central air conditioning system starts, a distributed generation system that otherwise meets all of the customer's energy needs may need additional power from the utility to allow the system to start.

The need for instantaneous power is summarized well by the Electric Power Research Institute:

“The grid provides instantaneous power for appliances and devices such as compressors, air conditioners, transformers, and welders that require a strong flow of current (“in-rush” current) when starting up. This enables them to start reliably without severe voltage fluctuation. Without grid connectivity or other supporting technologies, a conventional central air conditioning compressor relying only on a PV system may not start at all unless the PV system is oversized to handle the in-rush current.” *See*, “The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources,” Electric Power Research Institute (February 10, 2014).¹

Distributed Generation Customers Use the Grid to Ensure Reliability

The utility must have stand-by or backup power on hand to instantaneously serve customers, when the output from solar and wind generators is fluctuating, for example when clouds pass by or wind speed declines and then picks back up again. This resource variability creates uncertainty and can disrupt local grid system planning, causing a notable increase in generation re-dispatch events causing the grid to rely on the utility’s generating resources to offset the decline in solar or wind power production. Having these utility spinning reserves available to deal with intermittency incurs additional costs and with retail net metering, customers with distributed generation do not pay for them.

As described in the Electric Power Research Institute report discussed earlier:

“The grid serves as a reliable source of high-quality power in the event of disruptions to [distributed energy resources]. This includes compensating for the variable output of [photovoltaic] and wind generation. In the case of [photovoltaic], the variability is not only diurnal, but as shown in Figure 5, overcast conditions or fast-moving clouds can cause fluctuation of [photovoltaic]-produced electricity. The grid serves as a crucial balancing resource available for whatever period—from seconds to hours to days and seasons—to offset variable and uncertain output from distributed resources. Through instantaneously balancing supply and demand, the grid provides electricity at a consistent frequency. This balancing extends beyond real power, as the grid also ensures that the amount of reactive power in the system balances load requirements and ensures proper system operation.” *See*, “The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources,” Electric Power Research Institute (February 10, 2014).

Distributed Generation’s Two-Directional Power Flow Requires Changes to the Grid

People think a distributed generation system is less dependent upon the grid; however, distributed generation systems actually become more dependent on the grid. In fact, these systems require power to flow in two directions versus just one, which is how the grid system was initially designed.

According to a recent Massachusetts Institute of Technology Report:

¹ See, <http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=3002002733>

“Introducing distributed [photovoltaic] has two effects on distribution system costs. In general, line losses initially decrease as the penetration of distributed [photovoltaic] increases. However, when distributed [photovoltaic] grows to account for a significant share of overall generation, its net effect is to increase distribution costs (and thus local rates). This is because new investments are required to maintain power quality when power also flows from customers back to the network, which current networks were not designed to handle. [Emphasis added] Electricity storage is a currently expensive alternative to network reinforcements or upgrades to handle increased distributed [photovoltaic] power flows.” See, “The Future of Solar Energy”, MIT Energy Initiative (May 5, 2015).²

Initially, this change could adversely impact the distribution system requiring new investments in infrastructure. Voltage swings triggered by unpredictable fluctuations in output can potentially damage utility equipment and residents' home appliances; increase overall cost of maintaining the grid; require continued installation of larger, more expensive alternatives; and could even contribute to distributed outages.

“With the current design emphasis on distribution feeders supporting one-way power flow, the introduction of two-way power flow from distributed resources could adversely impact the distribution system. One concern is over-voltage, due to electrical characteristics of the grid near a distributed generator. This could limit generation on a distribution circuit, often referred to as *hosting* capacity. Advanced inverters, capable of responding to voltage issues as they arise, can increase hosting capacity with significantly reduced infrastructure costs.” See, “The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources,” Electric Power Research Institute (February 10, 2014).

New Two-Directional Communications Technology Needed to Ensure Reliability

Utilities will need a robust, sophisticated, two-directional communications technology that allows them not only to monitor what is happening with the distributed generation systems and the grid, but what to do about it when they experience operational issues associated with high levels of distributed generation penetration. Utilities may know where all that distributed generation is, but do not necessarily know how much electricity it is producing at any given time. That creates a huge “shadow load” that utilities cannot see, but which can affect operations. California is leading the way and will soon require “smart” functionality for all inverters that connect all solar to the grid.³ Small-scale solar inverters will be required to perform specific automated and autonomous grid-balancing functions they don’t perform today -- including several that aren’t allowed under the current national standards that regulate grid-connected devices. Smart inverters could also be a low-cost way to mitigate the voltage changes caused by the fluctuating wind and solar generation, thus preventing potential power quality problems.

² See, <http://mitei.mit.edu/futureofsolar>

³ See, “Rule 21 Smart Inverter Working Group,” California Energy Commission (http://www.energy.ca.gov/electricity_analysis/rule21/index.html)

Addressing Unfair Cost-Shifting

Today there are policies that do not require everyone to pay the same for grid services. For example, net metering is a policy that allows distributed generation customers to pay only for the power they do not make themselves (net power). When a distributed generation customer reduces their net usage from a utility (sometimes completely), the amount they pay for the grid services they use is significantly reduced because utilities recover most of the fixed costs of the distribution system in the volumetric charge for each unit of electricity their customers use. This is true even though the grid services are still needed all of the time – either to deliver power to the distributed generation customer or to deliver excess power from the distributed generation system to the utility as well as provide other critical services that are essential to operation of the grid, including voltage and frequency control. As a consequence non-distributed generation customers must pay for more of the grid services costs that are being used – but not paid for – by distributed generation customers. As the amount of distributed generation connected to the system grows, this unfairness will cause more costs to be shifted to non-distributed generation customers through higher rates.

As described by Harvard Professor Ashley Brown:

“Retail net metering overvalues both the energy and capacity of solar [distributed generation], imposes cross-subsidies on non-solar residential customers, and is socially regressive because it effectively transfers wealth from less affluent to more affluent consumers.” *See*, “Valuation of Distributed Solar: A Qualitative View” by Ashley Brown, Harvard Electricity Policy Group (December 2014).⁴

As with PURPA, the challenge here is that state electric rate regulation and ratemaking need to adapt to changes in the industry. Rate structures and tariffs are currently not designed for a rapidly growing new class of customers who generate their own power using distributed generation. For example, the fixed costs of generating electricity, maintaining transformers, keeping up underground and above-ground lines along with all the other parts of the electric grid today are borne by the customers largely through the volume of their electricity purchases, which is commonly referred to as “a volumetric charge.” So-called net metering programs or tariffs shift these fixed grid costs, which are not recovered through a separate rate design other than a volumetric charge, to non-solar customers, because rooftop solar customers aren’t buying as much electricity.

As described in the Massachusetts Institute of Technology report discussed earlier:

“In an efficient and equitable distribution system, each customer would pay a share of distribution network costs that reflected his or her responsibility for causing those costs. Instead, most U.S. utilities bundle distribution network costs, electricity costs, and other costs and then charge a uniform per-kWh rate that just covers all these costs. When this rate structure is combined with net metering, which compensates residential [photovoltaic] generators at the retail rate for the electricity they generate, the result is a

⁴ See, <http://www.ksg.harvard.edu/hepg/Papers/2014/12.14/Brown%20%20Valuation%20of%20%20Distributed%20Solar%20%202011.14.pdf>

subsidy to residential and other distributed solar generators that is paid by other customers on the network. This cost shifting has already produced political conflicts in some cities and states — conflicts that can be expected to intensify as residential solar penetration increases.”

“Because of these conflicts, robust, long-term growth in distributed solar generation likely will require the development of pricing systems that are widely viewed as fair and that lead to efficient network investment. Therefore, research is needed to design pricing systems that more effectively allocate network costs to the entities that cause them.” *See*, “The Future of Solar Energy”, MIT Energy Initiative (May 5, 2015)

Looked at another way in the context of the avoided cost standard of PURPA, utilities pay distributed generators the retail price for power, which includes the cost of electric energy as well as the fixed costs of delivery. The cost of the electric energy is the avoided cost. Since utilities are not purchasing delivery services from generators, this portion of their payment represents an amount in excess of “avoided cost.” This amount can be 50 to 60% of the retail rate. The difference is paid by other customers, effectively serving as a cross-subsidy for the distributed generation.

Addressing unfair cost-shifting means states need to revisit electricity rate design. Utility distribution operations also need to be redesigned to manage these “transactive loads” between the utility and customer generators at the micro-grid scale. Every customer who generates their own power should be compensated at a fair rate for the excess power they sell and they should pay a fair price for use of the grid services upon which they rely. The system can be fixed in a way that creates fair rates for everyone who uses the poles, wires and underlying electricity generating assets.

Three-Component Rates

An equitable solution to the cost-shifting discussed above is through the design of three part rate structures in state regulatory or legislative processes. Berkshire Hathaway Energy is already actively participating in regulatory and legislative conversations on this issue at the state and federal levels. We support the use of three-component rates for sales to distributed generation customers consistent with the cost of serving these “partial requirements” customers. The three components are a customer (\$/monthly bill) charge, a demand (kW) charge, and a power (kWh) charge. The three-component rate design has been used for decades to serve commercial and industrial customers and is familiar to regulators, but has not been common for residential customers because they historically did not produce their own electricity. Costs should be assigned among the components as nearly as practicable to reflect cost causation.

Incentivizing Smart Distributed Generation

Revisiting rate design also does not have to be one-sided. Customers with rooftop solar distributed generation systems will also benefit. For example, rooftop solar customers should be incentivized to move their system output closer to the utility power demand peak by installing western-facing modules to catch more late evening sun, instead of installing south-facing modules which may generate more power throughout the day, but not help with the afternoon

power demand peak on the utility's system. As a result, rooftop solar customers with western-facing modules that help lower the utility system's peak demand could avoid some demand charges for their power output.

A report by the Regulatory Assistance Project explains this opportunity:

"It is now generally accepted that orienting solar panels to the west-southwest increases the output during the afternoon hours, while reducing output during morning hours. This would produce a more valuable profile of power output, better suited to the shape of load to be served ... With time-varying rates, consumers will realize greater value from their [photovoltaic] investment by installing racking to orient the panels toward the west. Properly designed, this should compensate customers for any slight reduction of total [photovoltaic] output that results from this strategy – a significantly higher price per kWh for the same or slightly lower output." See, "Teaching the Duck to Fly" by Jim Lazar, Regulatory Assistance Project (January 2014).⁵

The Need to Work on Behalf of All Customers

Our utilities need to work with all of our customers to ensure the changes that result from distributed generation are managed effectively, so that we can continue to deliver safe, reliable and fairly priced power for all customers when they need it. That is why BHE supports Sen. Murkowski's (R-AK) proposal, S. 1219, because it encourages state utility commissions to examine cost shifting and determine whether the rates established for net metering services are "just and reasonable" and "not unduly preferential or discriminatory."

The issue of rooftop solar has led to extreme rhetoric on all sides. But the issue is not pro-solar or anti-solar, but fundamentally about equitable cost allocation among all customers, those with and without distributed generation. For customers who want solar power, the issue is how to provide it and interconnect them in the most cost-effective manner that is fair to them and to the utility's other customers who do not or cannot take advantage of solar. A 2008 study by the National Renewable Energy Laboratory (NREL) found that only 22 to 27% of residential rooftop area is suitable for hosting an on-site rooftop solar system.⁶ In the end, with proper rate design, recovery of fixed costs to maintain the grid should be assured so the utility may be agnostic as to whether a customer opts to install distributed generation.

Finally, we oppose Sen. King's (I-ME) S. 1213, the "Free Market Energy Act," as does the Edison Electric Institute. The proposed bill would expand federal jurisdiction over state electric distribution matters under which federal law currently preserves for state regulation. The bill establishes market rules that perpetuate preferences for small generation resources at the distribution level and are more costly than larger, utility-scale generation resources interconnected to the transmission grid. For example, Section 5 would amend Section 111(d) of PURPA to require state commissions and unregulated utilities to consider whether to apply the benefit(s), if any, with no mention of the cost associated with distributed generation for locational two-way valuations of time-of-use and/or real-time pricing for distributed energy

⁵ See, <http://www.raponline.org/search/site/?q=teaching%20the%20ducks%20to%20fly>

⁶ See, "Supply Curves for Rooftop Solar PV-Generated Electricity for the United States," National Renewable Energy Laboratory (Nov. 2008) <http://www.nrel.gov/docs/fy09osti/44073.pdf>

resources. While we are supportive of states and utilities taking up the subject, the bill explicitly authorizes compensating distributed generation providers for “the social value of distributed energy resources.” Payment of compensation for “societal benefits” is a huge step away from the cost-based or market-based principles traditionally used in electricity markets.

Section 6 would also vastly expand the scope of QFs under PURPA that are eligible to make mandatory sales to utilities at government-set prices. It allows QFs to receive rates above avoided cost. States would have to consider setting this new category of mandatory purchases from distributed generators at the utility’s full retail rate. It does not make economic sense to force customers to pay higher prices for excess distributed generation power when larger scale power that interconnects to the transmission grid can produce the identical benefits at a much lower cost.

Finally, Section 6 would also limit payments to help cover the fixed costs of the distribution grid to no more than \$10 per month regardless of the true cost. Because the fixed costs of the grid are usually far greater than \$10 per month, this provision shifts the balance of under collected fixed costs incurred to serve distributed generation customers to other customers using the grid.

Attachment A – BHE Text of Proposed PURPA Modernization Legislation

The proposed amendment, which would amend Section 1253 of the Energy Policy Act of 2005 (adding Section 210(m) to PURPA), reads as follows:

PURPA Section 210

16 U.S. Code § 824a-3 – Cogeneration and small power production

(m) Termination of mandatory purchase and sale requirements

(1) Obligation to purchase

After ~~August 8, 2005~~[insert date], no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to—

(A) (i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or

(B) (i) transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

(C) wholesale markets for the sale of capacity and electric energy that are, ~~at a minimum,~~ of comparable competitive quality as markets described in subparagraphs (A) and (B). For purposes of this subsection, any independently administered, voluntary, auction-based energy imbalance market, shall, by itself, be considered a market of comparable competitive quality as the markets described in subparagraphs (A) and (B), regardless of whether an applicable electric utility participating in such markets is a member of a regional transmission organization or independent system operator.

(D) For purposes of this subsection, qualifying facilities of any size are presumed to have nondiscriminatory access to wholesale markets described in subparagraphs (A) (B) or (C) above, if the qualifying facility in the relevant market (i) is eligible for service under a Commission-approved open access transmission tariff or Commission-filed reciprocity tariff, and Commission-approved interconnection rules; and (ii) can participate in competitive solicitations overseen by a state regulatory authority.