ONE-PAGE SUMMARY OF JONATHAN M. WEISGALL'S STATEMENT
BERKSHIRE HATHAWAY ENERGY
June 4, 2015

1. **Adopt the following set of PURPA modernization changes:**
   a. Expand the definition of "comparable markets" that are eligible for termination of the mandatory purchase requirement to include voluntary, auction-based energy imbalance markets and other sub-hourly markets.
   b. Terminate the mandatory purchase obligation upon a state regulatory agency determination if certain conditions are met.
   c. Eliminate the presumption in FERC regulations that QFs under 20 MW do not have nondiscriminatory access to markets if certain conditions are met.
   d. Enable utilities to rebut FERC's assumption that QFs are independent for purposes of applying the 20- or 80-MW size limitations where the sites are located more than one mile apart by demonstrating that the facilities are part of a common enterprise.

2. **Improve the federal transmission permitting, siting, and review processes.**
   a. Create a specific timeframe for federal agency review.
   b. Transfer the DOE's Section 216(h) lead agency coordinating authority to FERC or as an alternative create a "Transmission Ombudsperson" within FERC with authority to resolve interagency conflicts, set and enforce deadlines applicable to the other agencies participating in the review of a particular project, and require that any extension requests be approved first by the Secretary who has jurisdiction over the requesting agency.

3. **Encourage states to minimize cost-shifting among customers.**

STATEMENT OF JONATHAN M. WEISGALL
VICE PRESIDENT, LEGISLATIVE AND REGULATORY AFFAIRS
BERKSHIRE HATHAWAY ENERGY
BEFORE THE HOUSE ENERGY AND COMMERCE SUBCOMMITTEE ON ENERGY AND POWER
June 4, 2015

Introduction

Chairman Whitfield, Ranking Member Rush, and members of the Subcommittee, thank you for the opportunity to appear before you today as you consider legislation related to the accountability and energy efficiency aspects of the Committee's Architecture of Abundance energy package. My name is Jonathan Weisgall, and I am vice president for legislative and regulatory affairs at Berkshire Hathaway Energy (BHE). With our roots in renewable energy, BHE today owns three regulated U.S. utilities with customers in 11 states – MidAmerican Energy Company, PacifiCorp, and NV Energy – 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. We have also 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."

Thirty-seven years ago, Congress approved the Public Utility Regulatory Policies Act of 1978 (PURPA) in response to the oil crisis then gripping the country. PURPA's goal was to promote increased energy conservation and efficiency. Both the Federal Energy Regulatory Commission (FERC) and state regulatory commissions are responsible for enforcing PURPA.

Congress also wanted to encourage growth in the renewable energy sector. Section 210 of PURPA requires all electric utilities (including government-owned utilities and electric cooperatives) to purchase electricity at a government-determined "avoided cost" price from qualifying small power producers or qualifying cogenerators, all of which are known as qualifying facilities (QFs). Small power producers must generally use renewable or waste materials as fuel and are limited in size to 80 megawatts (MW) of installed capacity. Pursuant to FERC regulations, cogenerators must produce useful thermal energy to be used for industrial, commercial, or similar purposes, as well as electricity.

Generation from renewable energy resources, such as wind and solar, has increased substantially since PURPA was enacted. Renewable energy facilities have benefitted from technological advances, tax incentives, state renewable portfolio standards (RPS), federal and state subsidies, and numerous Environmental Protection Agency (EPA) regulations that have shifted the electric power industry away from coal-based generating facilities.

The PURPA 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. PURPA requires FERC to set rates that utilities must pay to QFs for their power at no more than "avoided cost." FERC gave state utility commissions the flexibility in determining a utility's avoided cost, the "incremental cost" to the electric utility of alternative electric energy. Under PURPA, these rates also have to be just and reasonable and nondiscriminatory and the utility must purchase the power from QFs even if they do not need it. PURPA contracts based on administrative determinations of avoided cost are notoriously inaccurate, and often exceed the cost of true utility options. This unduly increases rates to electric consumers, and, since PURPA contracts frequently run for as long as 20 years, PURPA locks in these high rates for the long term.

EPAct 2005

As a result of substantial abuses, particularly with respect to cogeneration facilities, Congress amended PURPA in EPAct 2005. Under the amended law, the mandatory purchase requirements of Section 210(m) of PURPA end if FERC finds that a QF has nondiscriminatory access to:

- Independently administered, auction-based, day-ahead and real-time wholesale markets for the sale of electric energy and access to wholesale markets for long-term sales of capacity and electric energy ("Day 2 markets"); or

- Transmission and interconnection services provided by a FERC-approved regional transmission entity 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 and electric energy to buyers other than the utility to which the qualifying facility is interconnected (“Day 1 markets”); or
- Wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as the markets described above.

<u>FERC’s Implementation of EPAct 2005</u>

In 2006, FERC issued new rules to implement the new Section 210(m) provision governing removal of the mandatory purchase obligation. In Order No. 688 (and subsequent orders), FERC created a rebuttable presumption that QFs having a capacity greater than 20 MW (large QFs) have nondiscriminatory access in the “Day 2 markets” of MISO, PJM, ISO NE, and NYISO; in the “Day 1 markets” of SPP; and the “comparable markets” of the California ISO (CAISO) and ERCOT. 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 having a capacity of 20 MW or less (small QFs) lack nondiscriminatory access to the three 210(m) markets, even if they are located within markets meeting the statute’s tests. This presumption has made it exceedingly difficult for utilities to avoid purchasing from small QFs, which could be as large as 20 MW, without limit, and regardless of whether the power is needed.

Any utility may file an application with FERC for relief from the mandatory purchase obligation showing how the conditions described above have been met. Absent an order from FERC granting the requested relief, however, a utility remains obligated to purchase power from QFs at a government-determined avoided cost rate.

Current PURPA Trends

There have been several trends occurring in recent years that indicate that PURPA's original intent to encourage independent generators is no longer necessary or useful. First, current PURPA provisions are imposing significant and unnecessary costs on utility consumers. Second, FERC has made it too difficult for utilities to obtain relief from the mandatory purchase obligation despite Congress' intent in enacting Section 210(m) in EPAct 2005 to limit that obligation. Third, FERC's "one mile" QF size calculation rule has resulted in the designation of multiple portions of larger energy projects as individual small QFs contrary to Congress' intent behind PURPA.

PURPA Mandates the Purchase of Power That May Not Be Needed.

In many instances, the power produced by QFs is not needed to replace base load 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 base load 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.

As the Subcommittee debates energy legislation, expanding the mandatory purchase obligation is unnecessary given changes to electricity markets that have occurred since the purchase mandate obligation was created 37 years ago. BHE does not support bills that would expand PURPA by requiring utilities to purchase electricity from QFs at prices in excess of avoided cost. With energy efficiency gains throughout the economy and new opportunities for customer generators, growth in customer electricity demand has slowed and many utilities simply do not need more generation. If a utility does need new generation, including renewable energy, competitive solicitations overseen by state regulatory commissions are the best means for acquiring a least-cost supply.

PURPA AVOIDED COST DETERMINATIONS OFTEN RESULT IN HIGHER PRICES.

Avoided cost determinations too often result in higher prices for consumers. Determining an appropriate avoided cost rate has been controversial from the beginning of PURPA. Government formulas (promulgated by the states and subject to FERC review) routinely fail to react to dynamic market conditions and often force utilities to enter into long-term contracts at prices that are substantially above-market, meaning electricity consumers pay more for electricity than they otherwise would**.** Whereas locational marginal prices are utilized in many markets to set rates for power, prices for PURPA power often bear no relationship to these market-based prices.

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 customers and undermine competitive 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.

<u>PURPA CONTRACTS ARE NOT SUBJECT TO THE SAME STATE RESOURCE SCRUTINY.</u>

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 process (IRP) 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 that relies upon competitive processes to acquire any long-term transaction or resource need identified in the IRP.

Under PURPA, however, utilities 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.

In 2010, FERC permitted states to provide additional incentives for QF development, including environmental "adders" and additional compensation for environmental externalities. That same year, FERC determined that where a state has adopted a policy to encourage a particular technology, the state can set avoided cost rates specific to that technology. For example, if a utility needs solar power to comply with a state RPS, FERC allows a solar QF to be paid the avoided cost of solar energy, even if it is above the utility's avoided cost of electricity generated by other sources of energy.

PURPA PROJECTS CAN CAUSE OPERATING INEFFICIENCIES AND RELIABILITY ISSUES.

The mandatory purchase obligation can cause operating inefficiencies and reliability issues on the host utility systems. Many QFs are "undispatchable" and might lead to over-generation conditions or inefficient use of base load 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.

FERC'S SECTION 210(M) MANDATORY PURCHASE OBLIGATION TERMINATION PROVISION IS TOO RESTRICTIVE AND CAUSES UNNECESSARY CONSUMER HARM.

In applying Order No. 688, FERC has determined that only utilities that have joined an independent system operator (ISO) or regional transmission organization (RTO) have satisfied FERC's market structure termination standards required for relief with respect to large QFs. However, not all utilities within these markets have been relieved of their PURPA must-purchase obligation based on their location within these markets and the transmission capacity that is available. With limited exceptions, FERC has denied the same relief with respect to small QFs. Thus far, other than ERCOT and CAISO, FERC has not found any "comparable markets" to exist.

Congress did not intend for EPAct's provisions for relief from the mandatory purchase obligation to apply only to utilities that have joined an ISO/RTO. The reality today is that utilities that have not joined an ISO/RTO have little or no ability to obtain relief from the mandatory purchase obligation for either large or small QFs. 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. In addition, even for utilities that are members of an ISO/RTO, EPAct's benefits thus far have been arbitrarily limited to QFs greater than 20 MW, without consideration of the harm such QFs can cause.

FERC'S "ONE-MILE" RULE HAS RESULTED IN GAMING TO AVOID STATE-APPROVED, NEW OR REPLACEMENT POWER COMPETITIVE SOLICITATIONS.

FERC currently has a "one-mile" rule for determining the size of a QF project, meaning that all QFs by the same owner using the same resource located within one mile are considered a single QF project. However, it is relatively easy for a QF developer to group wind turbines or solar photovoltaic (PV) arrays into separate corporate entities and locate them just beyond one mile from each other for the purpose of qualifying for PURPA. Contrary to Congress' intent in passing PURPA, increasingly, there is evidence that developers are deliberately structuring their projects for the sole purpose of qualifying as a QF, and thus the mandatory purchase obligation, under PURPA (maximum size of 20 MW in those areas where competitive markets exist; maximum size of 80 MW outside these areas).

For example, BHE's PacifiCorp utility has seen many developers across its six-state service area disaggregate large projects into smaller ones in order to qualify as a QF and take advantage of the PURPA mandatory purchase obligation as well as higher standard offer prices (awarded for smaller projects). A significant driver to this disaggregation activity is the ability of multiple QF projects, being pursued by the same developer, to share a common interconnection point with the utility's electrical system. Under these circumstances, each QF project, set one mile apart, will typically have a small collection substation and billing meter. Power from each QF project is metered and delivered via a feeder line to the main interconnection feeder, which then delivers to the interconnection substation deemed the point of delivery. Losses and station service are measured between the main point of delivery and each project meter and then allocated to the QF projects. This activity provides a cost benefit to the QF developer because interconnection costs can be spread across multiple projects versus a single project.

PacifiCorp-specific examples of disaggregation of large renewable projects into smaller projects:

Idaho. Prior to applying for a QF contract, one developer, Cedar Creek Wind LLC, a company jointly owned by Western Energy and Summit Power Group, had submitted a bid into PacifiCorp's 2008/2009 renewable RFP process as a single 151-MW wind project to be located in Bingham County, Idaho. PacifiCorp did not select the project through its RFP process because the offered price was too high and not competitive with other alternatives. In March 2010, the same developer requested QF pricing for two 78-MW projects, but the avoided cost rate offered at the time was too low. In May 2010, in an attempt to secure a more favorable standard rate, the developer reconfigured the project again, this time as five distinct projects, totaling 133 MW, all while still meeting FERC's one-mile rule.

- Steep Ridge (25.2 MW)
- Rattlesnake Canyon (27.6 MW)
- North Point Wind LLC (27.6 MW)
- Fine Pine Wind LLC (25.2 MW)
- Coyote Hill (27.6 MW)

Oregon. The Oregon Windfarm QF project located in eastern Oregon is a large 64.5-MW wind project that was disaggregated by the developer, John Deere Renewables, into nine QF projects ranging in size from 1.65 MW to 10 MW and constructed in 2008.[1] The projects were not independent family or community-based projects and clearly were a disaggregation of a large single wind project. The nine wind projects are operated today as a single wind project, delivering electricity to a single interconnection point on PacifiCorp's system, and are currently owned and managed by Exelon Generation, which acquired John Deere Renewables in 2010.

- Echo Big Top Wind Farm (1.65 MW)
- Echo Butter Creek Power (4.95 MW)
- Echo Four Corners Wind Farm (10 MW)
- Echo Four Mile Canyon (10 MW)
- Echo Oregon Trail Wind Farm (9.9 MW)
- Echo Pacific Canyon Wind Farm (8.25 MW)
- Echo Sand Ranch (9.9 MW)
- Echo Wagon Trail (3.3 MW)
- Echo Ward Butte Wind Farm (6.6 MW)

Utah. As of May 1, 2015, PacifiCorp has executed several large (50 MW to 80 MW) solar PV QF contracts in Utah where the developer secured a large generator interconnection agreement over 80 MW and then developed multiple adjacent large QF projects that feed into that interconnection agreement. For example, SunEdison has three 80-MW projects called Escalante I, II and III all adjacent to each other, technically meeting FERC's one-mile rule, but

[1] See, http://www.rnp.org/project_map

they are managed as a single project. In an earlier example of disaggregation, SunEdison and First Wind (later acquired by SunEdison) executed seventeen 3-MW standard offer solar PV QF contracts in 2013 and 2014. Several of these projects are built on a single land parcel, use a common interconnection point of delivery, and are constructed to meet the one-mile PURPA rule.

Wyoming. Currently, EverPower Wind Holdings is developing the Mud Springs Wind Ranch Project and requesting three 80-MW wind QF contracts for projects that are all adjacent to each other in Montana, again meeting FERC's one-mile rule, but sharing a common 230-kilovolt (kV) transmission line they are building into PacifiCorp's service area near Frannie, Wyoming, in order to secure Wyoming avoided cost prices. The three phases/projects will each be owned by a separate Limited Liability Company, but operated as a single large wind farm.

- Mud Springs Wind Ranch Pryor Caves Wind Project (80 MW)
- Mud Springs Wind Ranch Mud Springs Wind Project (80 MW)
- Mud Springs Wind Ranch Horse Thief Wind Project (80 MW)

FERC has not attempted to address gaming of its one-mile rule. FERC enforces its one-mile rule literally and has stated it will not examine whether larger projects have been divided into smaller projects in order to obtain QF status, so long as the projects comply with the one-mile rule. In particular, FERC has stated the one-mile rule does not contain a "rebuttable presumption" that may be used by a utility to contest the QF status of a given project. In *Northern Laramie Range Alliance*, 139 FERC ¶61,190, at PP 12, 22 (June 8, 2012),[2] FERC

[2] *See also DeWind Novus, LLC*, 139 FERC ¶61,201, at P25 (June 11, 2012) ("one-mile rule for determining whether small power generation facilities are 'at the same site' is a rule and not a rebuttable presumption").

rejected the argument that the one-mile rule contains a presumption that may be rebutted with evidence of gaming:

> "Contrary to the arguments of Petitioner… section 292.204(a)(2)(i) of the Commission's regulations was not intended to establish and did not establish merely a rebuttable presumption. Instead, section 292.204(a)(2)(i) established a rule that facilities that use the same energy resource, and that are owned by the same person(s) or its affiliates and that are located within one mile of each other are at the same site. There is certainly no language in that rule that suggests otherwise, i.e., that it is merely a rebuttable presumption. To the contrary, the language reads, as it was supposed to read, as a rule."

Based on the Commission's interpretation of its one-mile rule, utilities lack the ability to show FERC that projects are engaged in gaming in order to obtain QF status.

SUGGESTED LEGISLATIVE REFORMS

Electricity markets have changed significantly since 2005 when PURPA Section 210 was last amended. Natural gas prices and renewable energy technology costs have dropped dramatically while, at the same time, EPA regulations have contributed to making many coal-based generation facilities uneconomic. Many states have RPS mandates with increasing percentage requirements that have expanded opportunities for renewable energy developers. Distributed energy resources and the potential for micro-grids are increasingly popular with electricity consumers. Moreover, FERC's open access transmission and interconnection standards for large and small generators have worked extremely well, making it possible for a QF to sell its power to multiple buyers, not just the local utility.

As Congress debates energy legislation, some say PURPA and its mandatory purchase obligation is no longer needed and should be repealed. However, not all utilities operate in states where there is an organized market and not all state utility regulators require competitive bidding when a utility is looking to secure new or replacement power. In those states, PURPA and its mandatory purchase obligation still serve a useful public purpose. However, the changes in many other electricity markets since the 2005 PURPA amendments make a compelling argument for repealing a purchase mandate that was enacted 37 years ago. BHE agrees, and along with our national trade association, the Edison Electric Institute (EEI), believes Congress should adopt the following set of PURPA modernization changes:

1. Expand the definition of "comparable markets" that are eligible for termination of the mandatory purchase requirement to include voluntary, auction-based energy imbalance markets (EIMs) and other sub-hourly markets, irrespective of whether (a) the applicable electric utility participating in such markets is a member of an ISO/RTO, or (b) such a market has a governance structure and operation that is wholly separate and autonomous from an ISO/RTO.

2. Terminate the mandatory purchase obligation upon a state regulatory agency determination that (a) their electric utility has no need to acquire capacity or electric energy from a qualifying cogeneration or small power production facility within a given timeframe identified in its resource plan filed with such agency, or three years, whichever is longer, in order to meet its load serving obligation, or (b) the electric utility is subject to a state-required IRP process and competitive procurement processes for long-term energy or capacity resources that provide an opportunity for QFs to compete for any resource need identified in the utility's IRP process.

3. Eliminate the presumption in FERC regulations that QFs under 20 MW do not have nondiscriminatory access to markets, provided that (a) the QF is eligible for service under

a FERC-approved open access transmission tariff or a FERC-filed reciprocity tariff and FERC-approved interconnection rules, and (b) can participate in competitive solicitations overseen by a state regulatory authority.

4. Enable utilities to rebut FERC's assumption that QFs are independent for purposes of applying the 20- or 80-MW size limitations where the sites are located more than one mile apart by demonstrating that the facilities are part of a common enterprise.

The attached EEI proposed PURPA modernization amendment would accomplish these reforms. Each of these options would address one of the identified problems above. Not all of these proposals help all utilities, however. The one-mile rule proposal would help utilities that remain subject to the mandatory purchase obligation, while the other three proposals offer various types of relief from the mandatory purchase obligation itself.

First, expanding "comparable markets" under Section 210(m)(1)(c) would properly recognize the new opportunities that QFs of all sizes have today in certain regions to compete in wholesale electric markets for both short-term and long-term energy sales. This includes the voluntary, five-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 NV Energy joins the EIM in October 2014 and Arizona when Arizona Public Service Company joins the EIM in October 2016. 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." Additionally, the amendment properly recognizes that eligibility for termination of a utility's QF purchase obligation under PURPA should not be effectively tied to that utility joining any particular EIM or an ISO/RTO as a participating transmission owner, when doing so may not be in the best interest of its customers.

Second, terminating the mandatory purchase obligation upon certain state regulatory agency determinations provides an alternative means of relief for those utilities that otherwise lack access to an EIM or other sub-hourly markets. State-mandated IRP processes are where need for new resources (and the type of resources) is determined. As long as an electric utility is subject to a state-mandated IRP process and is subject to competitive resource procurement requirements, this should exempt them from the PURPA mandatory purchase obligation. Such processes provide QFs a fair opportunity to compete for the identified resource need. Importantly, by employing competitive procurement processes, the utility customers are assured of obtaining the best way of fulfilling the identified resource need.

Third, eliminating the 20-MW size demarcation for presumption of access to markets recognizes that with the creation of FERC-mandated standardized interconnection rules and procedures tailored for smaller facilities, FERC's existing size distinction is no longer warranted because open-access interconnection, transmission, and market access is available to QFs of all sizes. This change would also properly recognize 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 a utility competitive resource procurement process 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. Finally, this change would benefit a broader group of 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.

Fourth, creating a procedural means for utilities to show FERC projects are engaged in gaming in order to obtain QF status would be consistent with Congress' original intent in passing PURPA and check QF developers' current ability to impose significant costs on utility customers by exceeding the statutory and regulatory size limitations. Adoption of the change would also mirror the same anti-gaming procedural approach FERC took in Order No. 688, which stands in contrast to the rigid one-mile rule. There, FERC adopted several rebuttable presumptions with respect to nondiscriminatory access to the market based on the size of the QF. Unlike the one-mile rule, 18 C.F.R. §292.309(d)(1) contains an express rebuttable presumption that small QFs lack nondiscriminatory access to the market. In interpreting this rule, FERC stated:

> "The Commission will not allow for gaming of this 20 MW rebuttable presumption. If parties are concerned that a QF has engaged in gaming with regard to the certification or siting of a particular facility, we encourage those parties to bring their concerns to our attention. In any such proceeding, we will consider all relevant factors, including, but not limited to, ownership, proximity of facilities, and whether facilities share a point of interconnection. For purposes of evaluating proximity of facilities with regard to alleged gaming of this rebuttable presumption, we will not be bound by the one-mile standard set forth in 18 C.F.R. §292.204(a)(2)."[3]

Taken together, these reforms would modernize PURPA to remove its harmful elements for utility customers, recognize the changed circumstances facing most QFs today since the EPAct Section 210(m) provisions were adopted, and still ensure that QFs have meaningful opportunities to sell power in wholesale markets.

[3] *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688, at P 77 (October 20, 2006).

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

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.

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 EEI's and WIRES' 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.

The Administration's related RRTT reform effort, launched by the Department of Energy (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 National Environmental Policy Act (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 provided 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.

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.

SUGGESTED LEGISLATIVE REFORMS

BHE offers the following legislative recommendations with the above experiences and perspectives in mind. To meet national policy goals, BHE – and two trade associations EEI and WIRES – all 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 evolving resource mix that is being driven by a rapidly changing policy landscape. Congress should takes 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. We recommend including a specific timeframe for federal agency review. A January 2013 General Accounting Office study suggests review times could be reduced to 1.5 years with appropriate pre-application meetings.[4]

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 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.

[4] See, http://www.gao.gov/products/GAO-13-189

As an alternative, we would recommend creating a "Transmission Ombudsperson" within FERC with the authority to resolve interagency conflicts, set and enforce deadlines applicable to the other agencies participating in the review of a particular project, and require that any extension requests be approved first by the Secretary who has jurisdiction over the requesting agency. EEI and WIRES both support this approach as well. For example, there are instances where the Department of Defense has rejected proposed transmission routes meant to avoid endangered species habitat or to avoid more expensive undergrounding because the routes would be located near military training grounds. Our PacifiCorp utility's Boardman-to-Hemingway and Vantage-to-Pomona transmission projects are having difficulty finalizing their routes through the RRTT or the Pacific North West Renewable Infrastructure Team because of competing federal agency interests. Experience tells us that unless there is interagency consensus, the authorized officer will not make a decision and projects will linger.

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

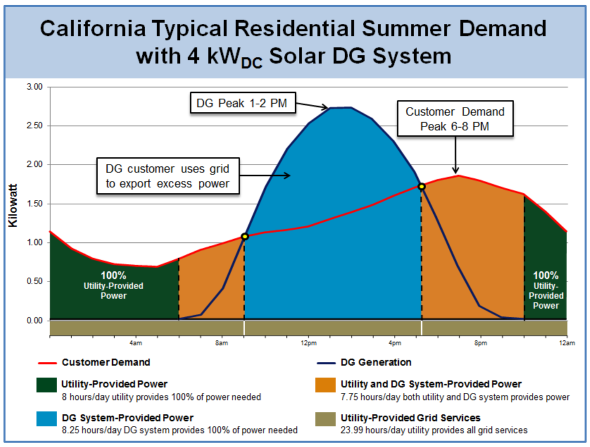
After a significant period of relative stability, the energy industry is evolving rapidly. New issues like distributed generation, electric vehicles, smart grid, energy storage, advancements in wind and solar technology, flat load growth and increasing environmental regulation, necessitate changes in 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.

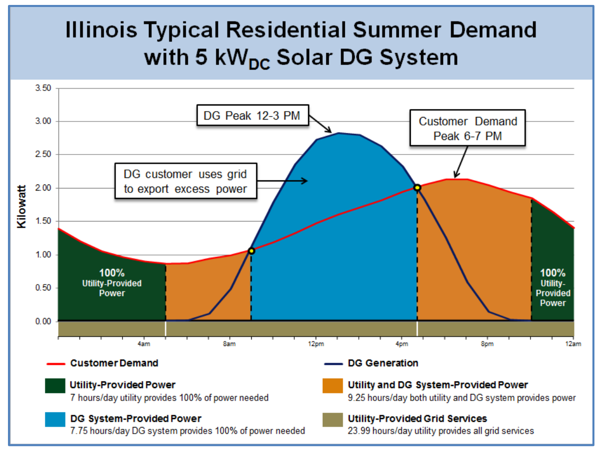
A Different Type of Customer, But Still Dependent on the Grid

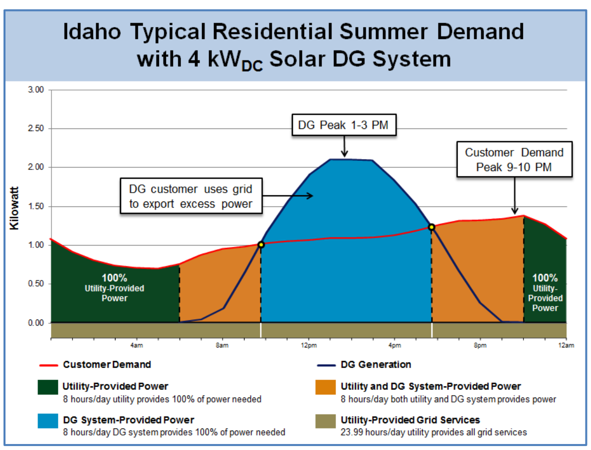
A growing number of our customers, both commercial and residential, are interested in generating their own power, through the installation of distributed generation. It's our responsibility to help our customers understand this option, because nearly all of the distributed generation customers will still 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.

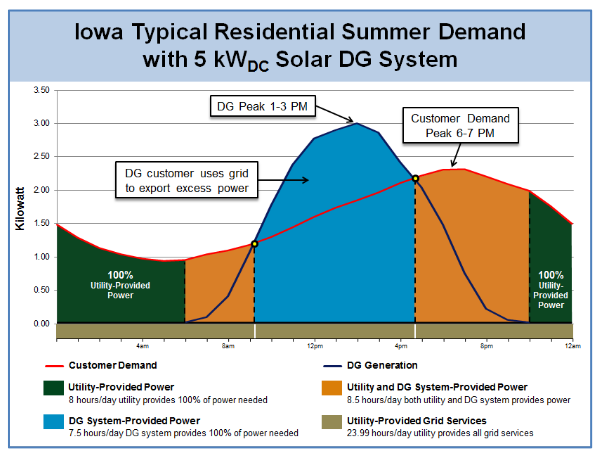
As distributed generation becomes an option for more consumers, three important things must be considered. First, distributed generation can be costly in comparison to utility scale generation. For example, although the cost of solar power has been declining steadily, the cost of utility scale solar 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 4 Kw units. All customers can benefit from utility scale solar and these systems can be integrated into utility control and dispatch processes.

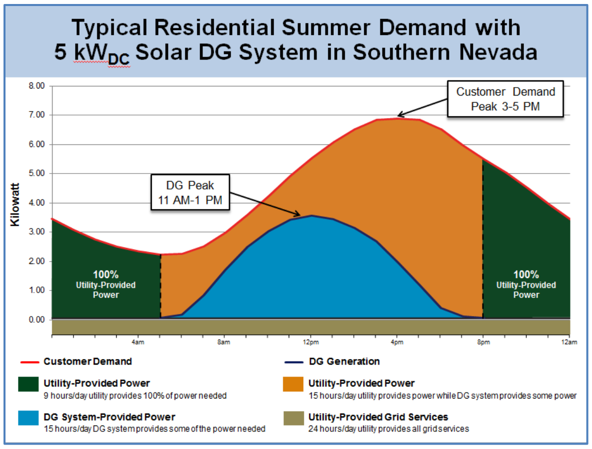
Second, today's distributed generation systems cannot function without the grid, nor can they fully meet the customer's electricity needs. For example, in the case of rooftop solar the following graphs illustrate the customer demand for electricity in different states over the course of a typical summer 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.

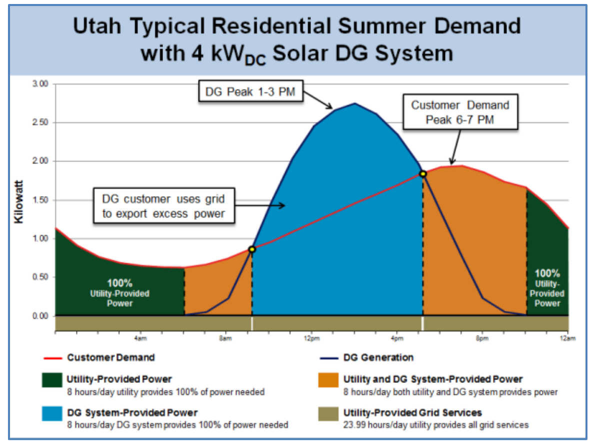


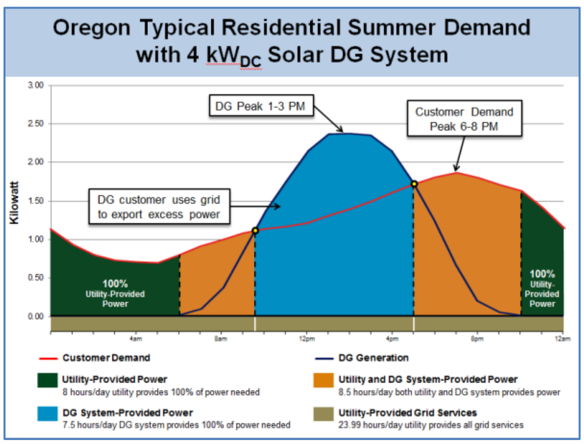


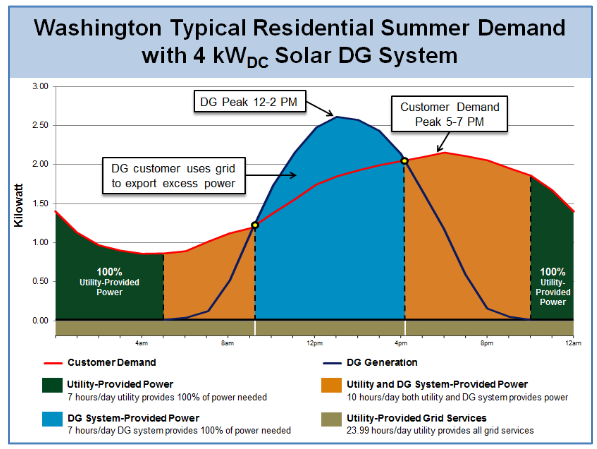


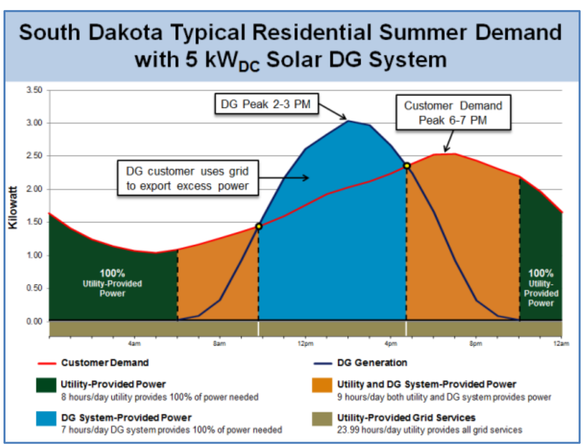


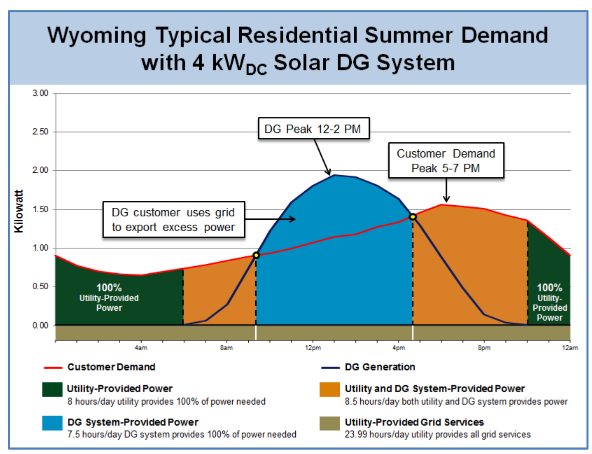












Third, utility grid services are needed 99.99% of the time to ensure power needs are met reliably and safely. The tan-shaded area along the bottom of each graph shows the utility provides all grid services 23.99 hours a day. Power is delivered through the utility's system to distributed generation customers 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.

<u>Distributed Generation Customers Still Need the Grid's Instantaneous, Start-Up Power</u>

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).[5]

<u>Distributed Generation Customers Use the Grid to Ensure Reliability</u>

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

[5] See, http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=3002002733

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).

<u>Distributed Generation's Two-Directional Power Flow Requires Changes to the Grid</u>

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:

> "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). <u>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</u>. [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).[6]

[6] See, http://mitei.mit.edu/futureofsolar

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.

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

> "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.[7] Small-scale solar inverters will be required to perform specific automated and autonomous grid-balancing functions they don't perform today – including

[7] See, "Rule 21 Smart Inverter Working Group," California Energy Commission (http://www.energy.ca.gov/electricity_analysis/rule21/index.html)

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.

<u>Addressing Unfair Cost-Shifting</u>

Today there are policies that do not require everyone to pay the same for grid services. Power produced by residential distributed generation systems connected to a utility's grid is compensated under existing tariff arrangements known as "net metering." Generally, net metering customers pay for the power they consume and are compensated for the power they produce at the retail price of electricity. The retail price for electricity includes costs associated for "grid services." (Grid services are also often referred to as fixed costs and include items like meters, wires, poles, and the vehicles service repair people drive to fix problems). Almost all of the costs for grid services are recovered from customers through a per-kilowatt-hour charge. Essentially, this means customers pay for these fixed costs based on how many kilowatt-hours they consume and without regard to when the power is acquired.

When distributed generation customers reduces their kilowatt-hour consumption because they are producing their own power (and getting paid for excess power), they ultimately pay less for "grid services." However, there is no corresponding reduction in the utility's costs for grid services because these fixed costs don't go away. All of the wires, poles, meters and vehicles are still necessary to continue to deliver the same safe and reliable power, even to those same customer generators who are never entirely off the grid. Instead, the loss in grid services revenue from owners of distributed generation systems must be made up by increasing the retail price paid by customers who do not have distributed generation systems. 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).[8]

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.

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 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)

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

[8] See, http://www.ksg.harvard.edu/hepg/Papers/2014/12.14/Brown%20%20Valuation%20of%20%20Distributed%20Solar%20%2011.14.pdf

the utility and customer generators at the micro-grid scale. Cost-shifting is improper because BHE does not believe it is fair for customers with distributed generation systems to shift the burden of paying for grid services to customers who do not have such systems. As distributed generation grows, it is important to remember that distributed generation customers are still dependent on the utility's grid services. This is the case when a distributed generation customer is not capable of producing all the power they need like at night, on a cloudy day, or when an appliance (e.g., air conditioner, refrigerator, or washing machine) may require supplemental power during startup. It is also the case when a distributed generation customer with net metering exports excess power back to the grid. Residential distributed generation customers are a different type of customer, because they use the grid very differently, a point best illustrated on the graphs presented earlier.

Three-Component Rates

BHE believes that every customer who generates their own power should be compensated at a fair rate for the power they sell back to the grid. They should also pay a fair price for use of the grid services upon which they rely. The system through new rate designs can be fixed in a way that creates fair rates for everyone who uses a utility's grid services. A three-component rate design is our preferred answer. 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, which measures how much power is used at any given point in time; and a power (kWh) charge, which measures the amount of electricity a customer uses over time.

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. Residential customers are rarely subject to a bill with a demand charge. This is because, until recently, residential electricity loads were pretty much the same from one customer to the next. Residential customers generally used greater amounts of electricity during the morning hours, then went to work, and in the late afternoon or evening when they returned from work began using greater amounts of electricity until they went to bed, whereupon their usage declines significantly. With each customer in the residential class looking a lot like the next, utilities and state regulators bundled power and demand costs together into a single $/kWh price. However today, this assumption is no longer true. All residential customers are not the same; respective loads and consumption patterns are potentially very different.

A demand charge is based on the maximum amount of energy a customer uses at any one instance over the course of a billing cycle. It reflects the cost that a utility incurs to maintain the grid in standby mode in order to reliably deliver electricity the customer wants, when the customer wants it. The distinction between how much electricity you need right now and how much you need in total over time is important. Historically, this has only been important for large industrial and commercial customers that require high amounts of power throughout the day. But as the penetration of distributed generation to electric vehicle charging to programmable, controllable thermostats to stationary energy storage grows, the demand charge can be a solution to more equitably collect grid costs as well as create a price signal that encourages efficiency, load shifting and peak demand side management. BHE believes that separating out demand charges is a good way to promote a more fair cost allocation among customers while also motivating customers to reduce strain on the grid. Critically, it is now inexpensive to meter these differences, including time-of-use and the magnitude of the demand. Costs should be assigned among the components as nearly as practicable to reflect cost causation. A demand charge would more equitably charge each customer for the service required from the grid closer to each customer's true cost of service.

As described recently by the Rocky Mountain Institute:

> "Demand charges are a promising step in the direction of more sophisticated rate structures that incent optimal deployment and grid integration of customer-sited [distributed energy resources]. A demand charge more equitably charges customers for their impact on the grid, can reward [distributed generation] customers with bill savings, and opens up potential for an improved customer experience using load management tools. It can also benefit all customers through reduced infrastructure investment and better integration of renewable, distributed generation." See, "Are Residential Demand Charges the Next Big Thing in Electricity Rate Design?" by Matt Lehrman, Rocky Mountain Institute (May 21, 2015).

Rate redesign and the use of demand charges are <u>not</u> meant to raise additional revenue collected by the utility, but rather to more directly allocate costs to customers based upon their actual use of the grid. The goal is also to create new and better price signals to encourage customers to become more efficient in both the *amount* and the *timing* of their electricity usage from (or delivery of excess energy to) the grid. Working together to define the rates will ensure the electric grid continues to be safe and reliable, while supporting a healthy and growing economy, including the continued growth of renewable energy sources and customer distributed generation options.

<u>**Incentivizing Smart Distributed Generation**</u>

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).[9]

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 legislation encouraging 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

[9] See, http://www.raponline.org/search/site/?q=teaching%20the%20ducks%20to%20fly

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.[10] 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.

[10] 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

Attachment A – Edison Electric Institute's PURPA Modernization Act

To update the Public Utility Regulatory Policies Act of 1978

A BILL

To modernize the Public Utility Regulatory Policies Act of 1978 to clarify circumstances in which the mandatory purchase requirements shall be terminated and to reduce opportunities for gaming

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. LOCATION OF QUALIFYING SMALL POWER PRODUCTION FACILITIES.

(a) REBUTTABLE PRESUMPTION. – The Federal Energy Regulatory Commission shall, within 180 days after enactment, amend its regulations implementing section 3(17)(A)(ii) of the Federal Power Act, 16 U.S.C. 796(17)(A)(ii), regarding the method for determining whether facilities are considered to be located at the same site as the facility for which qualification is sought for the purpose of calculating power production capacity, to provide a rebuttable presumption that two or more qualifying facilities are independent where the sites are located more than one mile apart.

(b) OVERCOMING THE PRESUMPTION. – In amending its regulations, the Commission shall allow any interested party to rebut the presumption in subsection (a) upon a showing that two or more facilities that are more than one mile apart are part of a "common enterprise." Factors that may be considered in determining whether an enterprise is part of a "common enterprise" for purposes of rebutting the presumption shall include the following:

(1) Whether the facilities have at least one common or affiliated owner or developer;

(2) Whether the owner(s) or developer(s) have treated the facilities as a single project for purposes of other regulatory filings or applications;

(3) Whether the facilities use the same energy resource;

(4) Whether the facilities have a common generator lead line, electrical infrastructure, or interconnect at the same or nearby point or substations;

(5) Whether the facilities have a common land lease or land rights;

(6) Whether the facilities have common financing; or

(7) Whether the facilities are part of a common development plan or permitting effort, even if the interconnection of the facilities occurs at separate points.

SECTION 2. TERMINATION OF MANDATORY PURCHASE REQUIREMENTS.

Section 210(m) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 824a-3(m)) is amended as follows:

(a) IDENTIFICATION OF COMPARABLE MARKETS. – Paragraph (1)(C) is amended

(1) by striking "for the sale of capacity and electric energy" and "at a minimum," in the first sentence; and

(2) by adding at the end thereof the following: "For purposes of this subsection, wholesale markets that are of comparable competitive quality shall include any independently administered, voluntary, auction-based energy imbalance market or other sub-hourly market, without regard to whether (A) an applicable electric utility

participating in such markets is a member of a Regional Transmission Organization or an Independent System Operator; or (B) such a market has a governance structure and operation that is wholly separate and autonomous from a Regional Transmission Organization or an Independent System Operator."

(b) PRESUMPTION OF NONDISCRIMINATORY ACCESS. – Subsection (1) is amended by adding at the end thereof the following new paragraph: "(D) For purposes of this subsection, qualifying facilities of any size are presumed to have nondiscriminatory access to the wholesale markets described in subparagraphs (A), (B) or (C) if the qualifying facility is (i) eligible for service under a Commission-approved open access transmission tariff or a Commission-filed reciprocity tariff and Commission-approved interconnection rules; and (ii) can participate in a competitive resource procurement process overseen by a State regulatory agency having ratemaking authority."

SECTION 3. RECOGNITION OF STATE DETERMINATIONS.

Section 210(m) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 824a-3(m)) is further amended—

(a) by redesignating paragraphs (3), (4), (5), (6), and (7) as paragraphs (4), (5), (6), (7), and (8), respectively;

(b) by inserting after paragraph (2) the following:

"(3) State Determination.—After the date of enactment of this paragraph, no electric utility shall be required to enter into a new contract or legally enforceable obligation to purchase capacity or electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the State regulatory agency having ratemaking authority over the electric utility has determined that: (i) the electric utility has no need to acquire capacity or electric energy from such qualifying cogeneration or small power production facility within the given timeframe identified in its resource plans filed with such State regulatory agency, or three years, whichever is longer, in order to meet its obligation to serve customers in the public interest; or

(ii) the electric utility is subject to a state required Integrated Resource Planning (IRP) process and competitive resource procurement process for long-term energy or capacity resources that provides an opportunity for qualifying cogeneration or qualifying small power production facilities to compete for any resource need identified in the electric utility's IRP process."

(c) in paragraph (4) (as so redesignated)—

(A) in the second sentence, by striking "of this subsection"; and

(B) by inserting "or in paragraph (3)" after "paragraph (1)" each place it appears; and

(d) in paragraph (5) (as so redesignated)—

(A) in the first sentence, by striking "paragraph 3" and inserting "paragraph (4)";

(B) in the second sentence, by striking "of this subsection"; and

(C) by inserting "or in paragraph (3)" after "paragraph (1)" each place it appears.