Powering America: Reevaluating PURPA's Objectives and its Effects on Today's Consumers

House Subcommittee on Energy

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Testimony
of
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On Behalf of the
Industrial Energy Consumers of America

Chairman Upton, Ranking Member Rush, distinguished Subcommittee members, thank you for the opportunity to testify before you today. My name is Stephen Thomas, Senior Manager of Energy Contracts for Domtar Corporation, headquartered in Fort Mill, South Carolina. Domtar manufactures pulp and paper products at nine mills across the United States and has cogeneration facilities at each of these facilities. Our Personal Care division manufactures adult incontinence products, baby diapers, and feminine hygiene products at four locations in the United States. We also have ten off-site paper converting facilities. I am here on behalf of my company and the Industrial Energy Consumers of America (IECA).

The Public Utility Regulatory Policies Act (PURPA) is just as important today as it was when first enacted into law in 1978. But, to help better understand how PURPA affects us, it is important to make a distinction between how the manufacturing sector utilizes PURPA and how it is utlized by renewable energy generators. While the manufacturing sector does cogenerate some electricity under PURPA, most of our generated electricity is consumed internally. For the manufacturing sector, the difference between what is generated and what is consumed on-site is purchased from the grid. Therefore, we are a net purchaser of electric energy.

As a net purchaser, we care a great deal about federal and state public policy issues that may increase electricity prices. This stands in stark contrast to renewable energy facilities whose business model is to generate electric power and then sell it at the highest price possible.

IECA is not asking for changes to PURPA, but if policymakers decide to do so, we urge you to support the enclosed IECA recommendations that would remove barriers to greater use of industrial combined heat and power (CHP) and waste heat recovery (WHR) and reduce costs and to not enact policy that will harm the viability of these vital facilities.

OUTLINE OF TESTIMONY

I. Industrial Energy Consumers of America
II. IECA Views on PURPA and Renewable Energy
III. Differences Between Industrial CHP/WHR versus Wind and Solar Electric Generating Facilities
IV. Policy Issues
V. Next Steps

I. INDUSTRIAL ENERGY CONSUMERS OF AMERICA

IECA is a nonpartisan association of leading manufacturing companies with $1.0 trillion in annual sales and with more than 1.7 million employees worldwide. IECA membership represents a diverse set of industries including: chemicals, plastics, steel, iron ore, aluminum, pulp and paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, building products, automotive, brewing, independent oil refining, and cement.

The great majority of IECA companies are energy intensive-trade-exposed (EITE) industries, which means that relatively small changes to the price of energy can have large impacts to competitiveness and jobs. IECA companies are some of the largest industrial consumers of electricity and natural gas in the U.S. and the world. EITE industries consume approximately 80 percent of all energy consumed by the U.S. manufacturing sector.

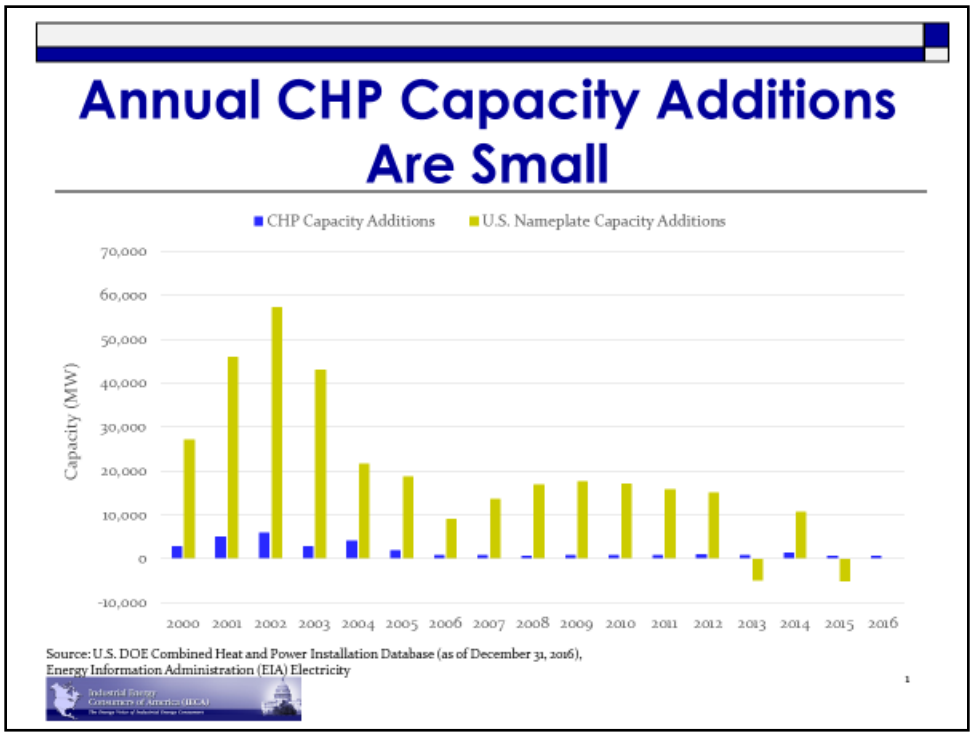
II. IECA VIEWS ON PURPA AND RENEWABLE ENERGY

IECA and its member companies support policy that allows energy producers of all types, including renewable energy, to compete head-to-head. When they do, consumers benefit from competitive electricity rates. Unfortunately, due to ambitious policy objectives and incentives, renewable energy producers have artificial advantages that are contributing to distorting electricity markets. These price distortions include downward pressures that result from taxpayer-funded subsidies and upward pressures from programs that require ratepayers to buy a certain percentage of renewable supply at premium prices. The lower capital costs might seem like a blessing, but they distort the Integrated Resource Planning (IRP) process and make it difficult for utilities to economically plan a generation supply to meet their long-term load growth forecasts.

Industrial CHP and WHR facilities operated by the manufacturing sector are not contributing to these market price distortions. In fact, there are several attributes of distributed CHP/WHR facilities that support the reliability of the grid, create and support manufacturing jobs, and provide environmental benefits.

It is for that reason, we urge states to recognize the differences between the types of qualifying facilities[1] (QFs) and only alter PURPA in a way that supports how the manufacturing industry uses PURPA, while minimizing artificial market pressures caused by the heavily subsidized renewable energy sector. And, total CHP/WHR electricity generation capacity is small relative to total U.S. electric generation capacity and has exhibited relatively minor capacity growth (see figure 1 below).

FIGURE 1



[1] Qualifying Facilities (QFs) is the term for generation facilities that qualify under PURPA rules.

Another advantage of CHP/WHR systems over dedicated renewables is that CHP/WHR is an industrial process that provides benefits on a predictable basis, usually 24/7, as compared to most dedicated renewable energy sources that only generate when the sun is shining or the wind is blowing.

State utility commissions[2] play a significant role in the implementation of PURPA as was contemplated by the original act. Accordingly, the FERC has delegated many responsibilities to state regulatory bodies. IECA supports the role that individual state commissions play in the implementation of PURPA and encourages them to consider this perspective.

1. IECA does not support renewable energy QFs manipulation of the one-mile rule to entice utilities to enter into long-term contracts under PURPA.

2. IECA does not support QFs of any type requiring electric utilities to pay for capacity under long-term contracts when the state utility commission has determined that the capacity is not needed.

3. State utility commissions should develop resource specific avoided cost rates to be able to assess each resource for the benefits provided and costs imposed on the ratepayers of the purchasing utility. IECA encourages states to account for the full cost of renewable energy when developing QFs avoided cost rates for such resources. The avoided cost paid to renewable generators should deduct the cost of natural gas back-up generation, transmission and other appropriate costs that can be directly tied to the integration of the renewable energy resource. As mentioned, the output of renewable energy QFs is variable and cause baseload generators to reduce operating efficiency as they compensate for lulls in sun and wind, thereby increasing energy costs per kWh for utilities and ratepayers. These costs should also be considered in developing avoided cost. In regulated and many market-based systems, it is the ratepayer who is paying for those baseload generating assets and we want them to operate efficiently and at high capacity factors because this results in the lowest costs for consumers.

4. Renewable energy QFs should not, in our opinion, be allowed to include Production Tax Credits (PTC) or the value of the Renewable Energy Credits (REC) into their calculation of their price-based bids into market-based systems because these price advantages distort the market price for electricity. Non-subsidized electric generators cannot compete with bids that are subsidized by these market credits. And now, renewable energy is contributing, along with low natural gas prices to the potential shutdown of nuclear and coal-fired generation plants. Even nuclear power plants that traditionally have very low fuel costs cannot compete in the market with subsidized renewable energy. Many states are considering even more subsidies to keep the nuclear generators operating. This will, of course, only lead to further distortion of electricity markets to the point all energy is subsidized. Ironically, these subsidies are paid for by consumers through taxes and higher fuel rates leading to little if any net benefit for the end-user.

[2] State utility commissions, generally identified as Public Service Commissions (PSCs) or Public Utility Commissions (PUCs) are the state regulatory bodies charged with approving rates that utilities are allowed to charge for water, sewer, electricity, natural gas and communication services.

III. DIFFERENCES BETWEEN INDUSTRIAL CHP/WHR VERSUS WIND AND SOLAR ELECTRIC GENERATING FACILITIES

a. Manufacturer owners of CHP/WHR facilities are large consumers of electricity and support policies that ensure that electricity costs are low and supply is reliable.

It is important for policymakers to appreciate that as manufacturing companies address the important issues of PURPA and CHP/WHR facilities, they must also understand that we are very large consumers of electricity that is purchased from regulated and market-based electric suppliers. For that reason, we support policies which result in ensuring that electricity costs are low and that supply is reliable. According to the Energy Information Administration (EIA), in 2015 industrial CHP generation was 145,712,028 MWh, while total manufacturing sector electricity consumption was 986,507,732 MWh. This means that manufacturers generated only 14.7 percent of their total U.S. consumption of electricity.

Large merchant wind and solar QFs are not large consumers of power, so they have completely different motivations. Their electricity purchases would usually only cover the facility parasitic load when their QF is running and emergency operations when the QF is not running.

b. Large merchant wind and solar facilities are in the business of generating and selling power. Manufacturers are in the business of selling their products to consumers.

Manufacturing companies do not build CHP/WHR facilities to sell power. Industrial CHP facilities are designed primarily for steam generation, and electricity is essentially a byproduct of that steam production. Industrial WHR facilities convert byproduct heat which is otherwise released into the atmosphere as power. Strictly from an energy perspective, CHP is substantially more energy efficient than stand-alone steam and power generation.

Excess power is sometimes sold into the wholesale market where Regional Transmission Organizations[3] (RTOs) exist and the utility has been relieved of their PURPA based “must-take” obligation. Excess power is also sometimes sold to the local electric utility at the electric utilities’ avoided cost.[4] The avoided cost is the cost for both energy and capacity that the utility avoids from buying from the QF, as opposed to obtaining that same amount of power using their own generation and other alternatives. In most jurisdictions, the avoided costs of the utility for capacity are based on the next type of unit the utility says they will install as established in their Integrated Resource Plan[5] (IRP), but not always, as not all utilities file IRPs. The avoided cost rate is set solely by the agency that regulates the electric utility in a state and is completely independent of the manufacturing company’s costs.

The need for a manufacturing company to sell excess power can be due to changes in the manufacturing process, such as when less steam from the CHP unit maybe required, while

[3] Regional Transmission Organizations operate large sections of the electric grid and guarantee non-discriminatory access and transmission pricing to all users of that section of the electric grid.
[4] Avoided cost is essentially the marginal cost for a public utility to produce one more unit of power.
[5] Integrated Resource Plan (IRP) is a written plan, usually with a 10 to 20-year planning horizon, for an electric utility’s expansion of its generation and transmissions systems. This plan defines what unit types need to be built and when.

simultaneously less power is consumed than what is generated. This is because the steam produced in the boiler remains constant and steam that is not extracted from the turbine is pushed to the condenser, thereby producing more power. For WHR, the byproduct power production varies with the manufacturing productivity. In some cases, CHP generators might even be able to overproduce to help the utility in times of great need, such as natural disasters. This adds to the stability and reliability of the electric grid.

c. CHP/WHR facilities have higher positive economic impacts and create and sustain more jobs.

Industrial CHP/WHR facilities are often the backbone of the manufacturing sector and provide continuous economic benefits for the manufacturing facility and the communities in which they operate. CHP/WHR helps the manufacturer lower its steam and electricity costs, which improves competitiveness, increases investment and job creation, and may increase exports of the products that are created. In contrast, most of the jobs and economic activity associated with wind/solar facilities are incurred only during the construction and installation process, and there are relatively few jobs associated with ongoing operations. The installation jobs are not high paying jobs like those in the manufacturing sector.

d. An industrial CHP/WHR facility connecting to the grid is not subsidized by other ratepayers.

Industrial CHP/WHR facilities, including the cost of connecting to the grid, are paid for by the manufacturer. If the interconnection request is for capacity and energy and the studies show that transmission upgrades are required to make the power deliverable to load, then the interconnecting CHP/WHR facility pays for the transmission upgrade upfront and are refunded those payments via credits on their bills for transmission service. These costs are not passed onto other electricity consumers. There are jurisdictions where the interconnection costs of renewable facilities are subsidized, which mean that the ratepayers are paying for it.

e. CHP/WHR facilities can potentially be considered a capacity safety net for the utility or wholesale market, while wind/solar are intermittent.

Manufacturers' CHP/WHR facilities run 24/7, producing steam and electricity to operate the manufacturing plant. In times of high electric demand or grid reliability problems, this excess CHP/WHR capacity has been called upon to supply desperately needed supplies of electricity. Often, we find that the local utility or the market values the potential capacity provided by CHP/WHR facilities. It can potentially act as a capacity safety valve. Wind and solar on the other hand are intermittent and operate at less than a 30 percent average capacity factor.

f. CHP/WHR facilities avoid significant transmission and distribution lines and line losses, while wind/solar do not.

When power generated by either the CHP/WHR facility is used onsite by the manufacturing steam host, transmission and distribution line losses are reduced. These line loss savings can be up to 7 percent.

g. Industrial CHP/WHR facilities avoid substantial quantities of emissions.

CHP is exceptionally energy efficient and avoids significant GHG and other criteria pollutant emissions.

CHP facilities, while not emissions free, provide an immediate path to lower GHG and criteria pollutant emissions through increased energy efficiency and avoiding emissions from other less efficient fossil fuel-based generating facilities and avoided line losses. According to the U.S. Department of Energy (DOE), current existing CHP facilities avoid 248 million metric tons of carbon dioxide per year.[6] Industrial CHP can produce electricity at up to 80 percent efficiency, as compared to around 34 percent for conventional coal or gas-fired combined cycle power generation and stand-alone steam production. CHP can use clean domestic energy sources, because over 83 percent of CHP capacity is fueled by natural gas, biomass, or waste fuels.

WHR electricity generation is emissions free.

WHR facilities use waste heat from the manufacturing process to generate power. As a result, WHR facilities do not generate additional emissions of any kind to produce power. This avoids GHG emissions that would otherwise be produced by the electric utility when generating that same amount of power.

IV. POLICY ISSUES

a. One-mile rule.

PURPA allows facilities to be treated as one QF if the facilities are within one mile of each other. Manufacturing QFs who develop CHP/WHR projects are not a party to this controversy since production facilities are often many hundreds of miles apart to avoid stressing the local infrastructures and supply chains. However, if it is found that wind and solar QFs are applying the one-mile rule in a manner that takes advantage of the PURPA mandatory purchase obligation provision, then changes should be made to the rule to protect ratepayers. One suggestion is to make the one-mile rule rebuttable so that utilities can challenge its application if they suspect it is being misused.

b. Capacity payments to QFs.

IECA Recommendation #1: FERC should provide new guidance that confirms state requirements to continue making contracted capacity payments to existing QFs, confirm state requirements to pay as available energy payments to existing and new QFs even if the IRP does not show a need for new capacity, and confirm state requirements to only contract for new capacity payments to QF supplier(s) when the IRP shows a need for the capacity. IECA also believes that state regulated utilities should not be allowed to recover capacity-related charges from ratepayers for new self-build renewable or QFs without demonstrating that the new facilities are the least cost alternative available to ratepayers.

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[6] Combined Heat and Power Technology Assessment, U.S. Department of Energy, https://energy.gov/sites/prod/files/2015/02/f19/QTR%20Ch8%20-%20CHP%20TA%20Feb-13-2015.pdf.

c. The rebuttable presumption that the Commission has adopted in the context of PURPA Section 210(m) that QFs with a capacity of 20 MW and below do not have nondiscriminatory access to competitive organized wholesale markets and the barriers to access encountered by these facilities.

The current regulation *unfairly discriminates* against industrial CHP/WHR in favor of entities, such as merchant wind and solar projects that are in the business of producing electricity for sale. This is because an industrial CHP/WHR installation with a net generating capacity exceeding 20 MW may still export far less total electric energy to the grid than a wind or solar facility of similar or even smaller capacity. CHP/WHR QFs that export small amounts of power should not be classified as either large- or small-based on the size of the net generation system after consideration of parasitic loads.

IECA Recommendation #2: The classification should be based on the maximum amount of power that potentially can be exported to the grid under normal operating conditions of the manufacturing facilities at which the CHP/WHR facility is located.

IECA supports retaining the PURPA rebuttable presumption for application to industrial CHP/WHR facilities that are 20 MWs or less. We believe that the intent of PURPA is to increase energy conservation/energy efficiency is still as important today as it was in 1978 and remains a very high public interest. In fact, it may be a higher priority today because of the need to reduce GHG emissions and support and grow a low-cost manufacturing base and create good paying jobs.

Manufacturers configure CHP units to supply internal demand for steam and power in the most efficient manner possible. From an operational standpoint, the priority will always be to produce enough steam to keep the manufacturing process operating with less regard to how much electricity is produced. In other words, manufacturing facilities have a strong and vested interest to not jeopardize production of product to increase production of electricity. At the same time electricity production is an important byproduct because it enables the manufacturing facility to be more competitive in global markets by lowering their production costs and/or developing supportive revenue streams.

The purchase obligation provides necessary protections for small projects with limited resources. Usually, it is only the utility that has the modeling and study information that can be used as an obstacle to QF development. This information can also be used to rebut the presumption that small QFs do not have access to competitive markets. Small QFs seldom have the information or knowledge of the transmission system and study assumptions to show that discrimination exists. For these reasons, the 20MW rebuttable presumption should be retained.

Many manufacturers with units 20 MW or smaller in size lack the expertise to sell the power to wholesale markets. The quantities usually available to sell into the market are so small, that it makes it impractical to establish the personnel and expensive back office resources necessary to do so. In addition, requiring such entities to become a market participant presents a significant challenge.

For example, if a QF became a market participant and offered a quantity of power into the day-ahead market and the QF was unable to deliver that amount, then the QF would be subject to true-up in the real-time market. If there is volatility between the day ahead and real-time rate, then the QF will be exposed to the risk of the price differential. If the price moved against them, the costs could be so high that it makes little financial sense to risk selling into the day-ahead market. As a result, the QF would most likely be limited to selling into the real-time energy market and forego the opportunity to know the value of that power on a day-ahead or longer-term basis, or to secure a capacity payment from the market. Finally, from a practical perspective, it should not be a burden for an electric utility to take these small increments of as available power from QFs that are CHP/WHR at the assigned avoided cost. The utility with whom the QF is interconnected is the logical off-taker of this energy.

If the rebuttable presumption were removed, the manufacturer would still need to get rid of the power that it cannot use internally. Because of the large financial risks of selling into the market versus the limited financial gains, we believe that most less than 20 MW units would reconfigure their units to produce less power so that there is never a possibility of an export taking place. This would reduce the energy efficiency benefits of the CHP facility which PURPA was enacted to promote.

If FERC were to consider changes to the rebuttable presumption, there should be consideration given to altering the minimum threshold so that it is based on total energy (MWh) exported to the grid, not on net system capacity. As stated earlier, the current regulation unfairly discriminates against industrial CHP/WHR in favor of entities, such as merchant wind and solar projects that are in the business of producing electricity for sale. It is entirely possible that an industrial CHP/WHR installation with a net generating capacity exceeding 20 MW (and typically a much higher overall capacity factor than merchant wind or solar), may still export far less total electricity to the grid than a wind or solar facility of similar or even smaller capacity. As stated earlier, facilities that export small amounts of power should not be classified as either large or small based on the size of the net generation system. The classification should be based on the maximum amount of power that potentially can be exported to the grid under normal operating conditions of the manufacturing facilities at which the CHP/WHR facility is located.

Utilities are currently afforded the opportunity to challenge or rebut the presumption that QFs smaller than 20 MW in size do not have nondiscriminatory access to competitive markets for their output. The opportunity to rebut should be retained. Utilities can rebut this presumption on a case-by-case review of each CHP/WHR QF to assess whether they have non-discriminatory access to markets. In evaluating such challenges FERC would need to consider multiple factors that include: physical configuration, operational considerations, and federal and state legal and regulatory issues. We note that it is not appropriate for a regulatory agency such as the FERC to change the energy conservation requirements and goals embedded in PURPA or to propagate new rules that would effectively result in this outcome.

d. Avoided cost calculations.

The design of avoided cost rates was delegated to the states by PURPA. The most important issue for ratepayers is paying the lowest cost for each utility capacity addition whether through utility construction or via a Power Purchase Agreement (PPA) with a QF.

IECA Recommendation #3: IECA encourages FERC to improve its guidance to states for the determination of avoided cost. Avoided costs should be reasonable, fair, and equitable to both the QF, ratepayers, and other market participants.

Avoided costs should be comprised of both avoided energy and avoided capacity components. However, a capacity payment should only be offered if the IRP shows that additional capacity is needed or the utility is adding certain capacity regardless of need to fulfill state policy objectives. The QF should enable the utility to defer this new construction or delay entering into the PPA for that capacity. Energy only avoided costs should be established if the utility is not seeking to install new capacity.

IECA believes that the Differential Revenue Requirements (DRR) approach for establishing avoided cost for energy is a proven and workable approach that pays the QF a fair avoided cost rate for energy at the retail level. The DRR approach uses the utility model and their projected total costs of operating their system with and without a specified block of QF power. These models can be PROMOD[7] or other utility cost modeling programs. The block can be either 100 MW or 200 MW depending on the state's interests. The avoided energy rate is the difference between the results of these two modeling runs. The results can be broken down into on-peak and off-peak energy rates and can be further differentiated on a seasonal basis.

This calculation should be done on an annual basis in an open, public, and well-publicized utility commission proceeding in advance of the upcoming year so that QFs can review the calculations and have some certainty of the payments they will receive for energy in the upcoming year. This methodology will reduce the use of long-term energy forecasts in proxy units for developing avoided cost energy rates and will prevent avoided costs for energy from deviating significantly from the actual costs avoided by the utility.

Avoided cost payments for capacity should be based on the utility's stated need for capacity as outlined in the utility IRP. If the utility does not produce an IRP, then the unit of capacity that is used for this calculation should be based on the utility's public statements of their future capacity needs. Those needs can be either to meet load growth, reserve margin requirements or to fulfill other state policy objectives.

IECA Recommendation #4: The avoided cost rate for capacity should be offered for a minimum 10-year term. This would give the QF some pricing certainty, which can be relied on to obtain financing.

When power generated by the CHP/WHR facility is physically used onsite by the manufacturing steam host, transmission, transformation and distribution line losses are reduced as well. These line loss savings can be up to 7 percent. Avoided cost calculations should continue to include a line loss adjustment for QFs that use the power at an adjacent consuming site and not if the power is transmitted some distance to get to load.

[7] PROMOD is a market simulation and production cost modeling software by ABB, a somewhat industry standard for cost modeling at the utility level.

IECA Recommendation #5: Avoided cost calculations for wind and/or solar facilities should account for the cost associated with under-utilizing existing electric generation capacity when wind/solar are generating power.

States should consider the additional costs imposed on the system by intermittent QFs and reduce the avoided cost rates to those QFs accordingly. Wind and solar are intermittent and operate at less than a 30 percent average capacity factor. The utility that buys QF power from such intermittent resources incurs additional costs to integrate that resource into their mix. The avoided cost rates paid to such intermittent resources should therefore be adjusted downward to reflect these additional costs incurred by the buying utility.

IECA Recommendation #6: FERC should provide guidance to states to ensure that capacity and energy costs are appropriately allocated to the rate classes after the functional separation is done properly. In regulated jurisdictions, the capacity portion of the PPA should be added to the utility's base rates, while the variable energy portion should be included in the fuel rate.

IECA Recommendation #7: FERC should provide guidance to states regarding the review of PPAs, such that state commissions are required to hold a public proceeding on the merits of the PPA prior to the state commission's decision making. Transparency is sound public policy. We find all too often that state commissions do NOT hold such proceedings. Since PPAs have the potential to raise electricity rates and state commissions always have generation alternatives, ratepayer participation should be included in the approval process.

e. Curtailment issues.

To address the curtailment issue, it is important to acknowledge that not all generation resources are similar with regard to reliability, capacity, and total economic impact of curtailment to the electric generator. All three are important factors that should be considered when decisions are made to curtail generation. If a need to curtail generation arises, it is because there is more generation available than needed to meet the instantaneous demand. At this point the price signals in the energy market should have already reduced the thermal generators' output to absolute minimum levels required for production. The remaining generation on the system will be QFs, nuclear, hydro, and some natural gas generation. Since it is not practical to curtail some hydro or nuclear units, the next choices are QFs and the remaining natural gas generation units.

IECA believes QFs that are small power producers under 80 MW or less should be curtailed before QFs that are CHP/WHR units. This is because the overall impact to the economy will be less as wind and solar electric generating units do not have an entire manufacturing site tied to them. Industrial CHP/WHR systems can be the backbone of the manufacturing facility which provides continuous economic benefits for the communities in which they operate. CHP/WHR helps the manufacturer lower its steam and electricity costs, which improves competitiveness, increases investment and job creation, and may increase exports of the products that are created. In contrast, the overall economic benefits of wind/solar facilities are far less.

Industrial CHP/WHR facilities should only be curtailed if the grid is truly in an emergency situation and the stability of the grid is being threatened. The CHP/WHR facility should only be

curtailed down to a net zero export position. CHP/WHR facilities are often located in remote rural locations and can provide much needed voltage support.

In the reverse situation where the grid becomes unstable because there is insufficient generation to meet instantaneous demand, many CHP/WHR units have the ability to shift their load/generation profile to actually help stabilize system loads to reduce the impact of grid capacity shortfalls. Such assistance from CHP/WHR units would enable the grid operator to avoid triggering cascading blackouts. CHP/WHR units are reliable and run continuously when they are serving a manufacturing facility. The CHP unit is producing steam and electricity that is essential to keeping the associated manufacturing facility operating.

If the entire CHP facility is curtailed (and not curtailed only to zero export level), then the entire manufacturing facility will not be able to operate efficiently and as stated above, there will be significant economic harm. The manufacturing facility will incur great financial loss which includes lost production, and operating expenses to shutdown and then start-up of the entire manufacturing facility. Hundreds, if not thousands, of employees would not be able to work. These costs are significantly greater than shutting down facilities such as wind and solar, natural gas, or even coal-fired production facilities. CHP/WHR should be the last in the queue to be curtailed right before nuclear and hydro units.

Policies that deal with curtailment need to address the problem of the aggregated unpredictable impact of wind and solar facilities. While there may be several wind and solar facilities in a given region, they are a block of resources that act together with important implications for the grid. This means when the wind is not blowing and/or the sun is not shinning, all of the turbines in the region are not generating electricity. As such, wind and solar facilities have a disproportionate impact. In contrast, CHP/WHR units act alone at the single industrial site where they are installed (i.e. a condition at one CHP/WHR unit will not impact another CHP/WHR unit in the same region).

f. Interconnection issues.

IECA Recommendation #8: IECA supports the development of a streamlined interconnection approach specifically designed for CHP/WHR QFs that are part of a manufacturing facility in order to lessen the burden of interconnection for those QFs. The reason for this is that industrial CHP/WHR units are not in the business of selling power, yet units greater than 20 MWs are required to go through the same FERC or RTO interconnection process for large generators, just like an electric generating utility unit. This subjects the CHP/WHR QFs to considerable expense, time, and resources to go through the interconnection process. This is not necessary and discourages potential QFs from pursuing the CHP/WHR project.

IECA recommends that FERC modify the rules to accommodate all industrial CHP/WHR facilities. IECA recommends that any CHP/WHR facility whose steam host (or heat host for WHR) is a manufacturing company that is owned and operated by a company within the NAICS codes of 31-33, and whose primary purpose is to produce steam and electricity for on-site consumption, would qualify for the FERC-approved streamlined interconnection process for small generators, regardless of voltage of the interconnection or size of the facility.

Interconnection costs and cost allocations.

All QFs should pay the upfront cost of upgrading the transmission system as part of the interconnection process if the QF wants to become interconnected as a capacity resource. FERC accepted a proposal made by MISO to allocate transmission upgrade costs across the entire MISO footprint on an energy basis for certain types of new transmission facilities as just and reasonable, despite longstanding FERC policy to allocate transmission costs on a demand basis. This decision was made to lessen the cost burden on utility systems located in parts of the MISO where wind power is being built.

These high voltage facilities are called Multi Value Projects (MVPs) in the MISO. FERC stated that it is just and reasonable to socialize the cost of new infrastructure needed for the development of renewable energy projects over the entire MISO footprint and not just to the QF seeking the interconnection. ***It is inconsistent with cost causation principles to charge all MISO transmission owners for transmission upgrades for MVPs on certain parts of the system where they will not derive any benefit.*** Furthermore, allocation of these costs on an energy basis is unfair to energy-intensive high load factor manufacturers who purchase power from utilities in the MISO footprint because this allocation methodology imposes a much larger share of these cost burdens on those specific customers.

IECA Recommendation #9: We believe there are jurisdictions where the interconnection costs of small renewable facilities are subsidized by ratepayers. FERC should provide guidance to states and RTOs/ISOs to revert back to the allocation of transmission costs based on demands created on the system, not on energy used. In addition, transmission upgrades needed for QFs to become capacity resources should be borne by the QF seeking the interconnection and not socialized to consumers across a wide footprint when those consumers will not derive any quantifiable or tangible benefit from these projects.

g. The obligation to purchase as available power issues.

It is important to retain the obligation of utilities to purchase as available power from CHP/WHR facilities, particularly in jurisdictions where there are non-competitive or non-existing transparent wholesale power markets. It was the clear intent of Congress through PURPA to protect CHP/WHR and other QFs from discriminatory treatment.

Unfortunately, as there have been so many times in the past, there is an ongoing effort to suggest that the mandatory purchase obligation is no longer needed in states if the purchase is not necessary to meet the utility's obligation to serve or if the utility conducts an RFP. The obligation to purchase as available power is still needed as it is essential to the operation of CHP/WHR facilities. FERC should not sanction any state action that would undermine the must buy obligation as this would be contrary to the very reason Congress enacted PURPA in the first place.

The loss of obligation to purchase as available power would diminish the value of the excess power produced and would likely result in CHP/WHR facilities voluntarily reducing power production, due to having no viable market available for its sale. CHP/WHR operators would subsequently incur the previously mentioned inefficiencies and losses associated with reduced power production. Putting excess power to the grid without requisite authority to do so or

submitting a schedule that does not reflect actual excess power generated may subject the CHP/WHR facilities to imbalance penalties. QFs need the ability to put power to the local utility on an as available basis.

h. The obligation to sell supplemental, standby (backup), and maintenance power to a QF.

The obligation to provide supplemental, standby (backup), and maintenance power to a QF at just and reasonable rates should be retained as these services are essential to the viability of industrial CHP/WHR facilities. Guidance for development of rates for these services was provided by the FERC in Section 292.305. These principles specify that the design of rates for these services should not be based under the assumption that forced outages by QFs will occur simultaneously or during the system peak, or both. Although the FERC provided such guidance/principles to the states on parameters to consider when designing these rates, the actual rate designs vary greatly by state and utility system. *This is because the states that were unfriendly to PURPA largely ignored this guidance and approved rate designs that actually discouraged industrial companies from building CHP/WHR facilities.* Properly designed standby and maintenance rates should be just and reasonable, based on cost causation principles outlined by the FERC.

Some electric utilities charge disproportionate amounts for capacity and transmission in the event that there is even the slightest trip of the CHP/WHR unit that is not coincident with their peaks. This becomes very costly to the QF if the demand charges for standby service ends up being very similar to the demand charges for full retail service.

IECA Recommendation #10: FERC needs to further encourage states to design rates for these services based on the load the QF contributes that is coincident with the total loads at the system peak. An alternative, less volatile approach, would be to design standby rates assuming that these services will only be required 10-15 percent of the time and rarely, if ever, during the system peak. This principle is applicable to allocation of generation (capacity) and transmission costs.

i. The impact of emerging energy imbalance markets may have on the mandatory purchase obligations.

Balancing markets do not qualify as comparable markets under 210(m)(1)(c). Balancing markets vary greatly, can be of poor quality, and most typically lack liquidity. The imbalance penalties alone are reason enough why use of these less than fully developed markets should not be allowed to relieve utilities of the mandatory purchase obligation. Manufacturers with CHP units are risk adverse. Imbalance markets are real time markets which do not provide pricing certainty on a day-ahead basis. Participation in energy imbalance markets may also require dispatchability that is impractical for CHP/WHR facilities or is inconsistent with the energy efficient operation of the CHP/WHR facility.

IECA Recommendation #11: Energy imbalances caused by renewable resources result in unrecognized costs imposed on ratepayers because utilities and RTOs have to fill the voids caused by this resource's intermittency with other resources. These incremental costs are not considered in developing avoided costs for these facilities. IECA recommends that FERC

addresses this issue. However, we do not believe that CHP/WHR units tied to manufacturing facilities are contributing to this problem because their intermittent sales of excess power are relatively small.

Intermittent wind and solar units can submit negative bids, thereby depressing energy clearing prices for all resources, including baseload resources. They can submit negative bids because the value of the federal Production Tax Credit (PTC) and the Renewable Energy Credit (REC) are typically included in their bids. This distorts the market, creates unfair advantage and makes it harder for other resources to compete. In addition, if thermal baseload power plants do not get dispatched because they do not clear the market they will lose value, ultimately resulting in permanent premature shutdown. In regulated markets, ratepayers continue to pay for electric generation plants that are shutdown before their useful lives have been met. As the percentage of renewable energy in the market increases going forward and load growth is low or nonexistent, more baseload power generating facilities will not be dispatched to run. Eventually those plants will be shutdown prematurely at the cost to the ratepayer. U.S. policymakers should carefully review what has already happened in the UK and German electricity markets as a clear warning.[8]

At the same time, imbalances created by renewable resources may potentially make the grid unstable. PJM has stated that they can absorb about 30 percent renewables on their system, but that grid resiliency will have to be studied and any issues identified will have to be addressed if the studies show there are concerns when renewables exceed those percentages. Although each part of the country has their own unique set of circumstances at play, it is clear that as the percentage of renewables increases, grid operators will become more and more challenged to maintain grid balance.

j. IECA position on charges for standby service.

The development of rates for **s**tandby service was delegated in PURPA to the states. Although PURPA provided guidance to the states on parameters to consider when designing standby rates, the actual rate designs vary greatly by state and utility system. This is because the guidance provided in PURPA was not specific enough to prevent states that were unfriendly to PURPA from putting forward rate designs that actually discouraged industrial companies from building CHP/WHR facilities.

First, it is important for policymakers to understand that industrials have every incentive to operate. If we are not operating, we are not producing manufacturing products or widgets and we are not recovering fixed costs. If a CHP/WHR unit is not running it is because there is a temporary shutdown, either a forced outage or a planned maintenance outage, of the manufacturing facility which uses the steam from the CHP unit. Properly designed standby rates should be just and reasonable and based on well-established cost causation principles.

IECA Recommendation #12: Fair standby charges should reflect the utilities actual avoided cost. Unfortunately, there is a significant problem in that some electric utilities charge disproportionate charges in the event that there is even the slightest trip of the CHP/WHR unit.

[8] "How Renewables Killed the British Energy Market," "Amber Rudd: end to pursuit of green energy at all costs," Telegraph, November 15, 2015.

In some cases, even if these QFs are not operating for half a minute, the industrial would pay the entire standby service demand charge for the month based on the single highest consumption increment. IECA recommends that FERC develop more detailed guidance to the states for the development of standby rates, than what is outlined in PURPA today.

k. IECA position on behind the meter and solar not paying its fair share of T&D fixed costs.

This too is a state policy issue which is usually addressed in state net metering rules. IECA believes that residential rooftop PV solar energy, produced behind-the-meter, needs to pay its fair share of transmission, distribution, and maybe even some generation costs because of the intermittency of the resource. Otherwise these costs are being paid for by remaining electricity consumers in the residential sector who have not installed the solar facility. Sometimes regulators will allocate certain unrecovered costs to other customer classes as well. Sound ratemaking policy should prevent cross subsidization within a customer class sector and between customer classes.

V. NEXT STEPS

Thank you for the opportunity to testify before the Subcommittee. We look forward to working with you, FERC, and the states to address these important issues. In closing, we reaffirm our view that IECA is not asking for changes to PURPA. But, in the event that policymakers do move forward to do so, we ask that they support IECA recommendations, which remove barriers to greater use of industrial CHP/WHR and to not enact policy that will harm the viability of existing facilities. Doing so, increases the ability of the U.S. manufacturing sector to invest here in the U.S. and create high paying middle-class jobs.

For additional information and resources, please contact IECA.

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FIGURE 2

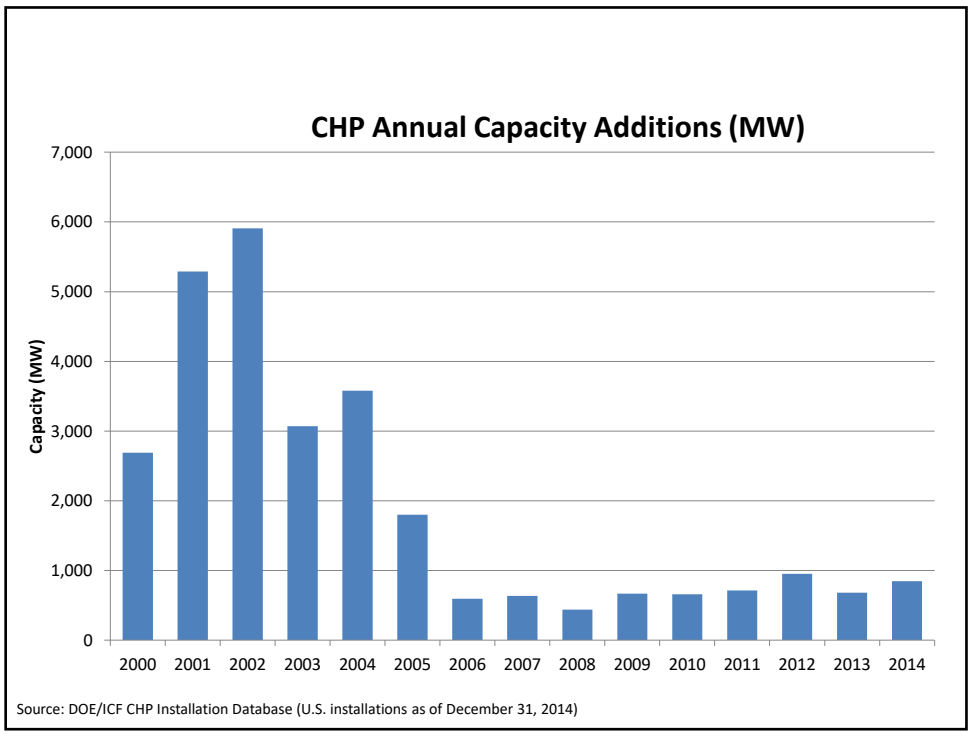

FIGURE 3