CONTENTS

Hon. Fred Upton, a Representative in Congress from the State of Michigan, opening statement ........................................ 1
Prepared statement .................................................................................................................. 3
Hon. Frank Pallone, Jr., a Representative in Congress from the State of New Jersey, opening statement .................................................. 4
Hon. Greg Walden, a Representative in Congress from the State of Oregon, opening statement .................................................. 5
Prepared statement .................................................................................................................. 6

WITNESSES

Frank Prager, Vice President, Policy and Federal Affairs, Xcel Energy ............................ 7
Prepared statement .................................................................................................................. 10
Answers to submitted questions ......................................................................................... 134
Todd Glass, Counsel, Solar Energy Industries Association ............................................ 25
Prepared statement .................................................................................................................. 27
Answers to submitted questions ......................................................................................... 139
Kristine Raper, Commissioner, Idaho Public Utilities Commission .............................. 48
Prepared statement .................................................................................................................. 50
Answers to submitted questions ......................................................................................... 149
Stephen Thomas, Senior Manager, Energy Contracts, Domtar Paper Company .......... 59
Prepared statement .................................................................................................................. 61
Answers to submitted questions ......................................................................................... 156
Terry Kouba, Vice President, Iowa Operations, Alliant Energy ................................. 78
Prepared statement .................................................................................................................. 80
Answers to submitted questions ......................................................................................... 161
Darwin Baas, Department of Public Works for Kent County, Michigan ....................... 92
Prepared statement .................................................................................................................. 94
Answers to submitted questions ......................................................................................... 165

SUBMITTED MATERIAL

Statement of Cypress Creek Renewables, submitted by Mr. Walberg ...................... 129
Statement of the Northwest & Intermountain Power Producers Coalition, submitted by Mr. Walberg ................................................................. 133
The subcommittee met, pursuant to call, at 10:00 a.m., in room 2123 Rayburn House Office Building, Hon. Fred Upton (chairman of the subcommittee) presiding.


Staff present: Ray Baum, Staff Director; Elena Brennan, Legislative Clerk, Energy/Environment; Jerry Couri, Chief Environmental Advisor; Zachary Dareshori, Staff Assistant; Wyatt Ellertson, Research Associate, Energy/Environment; Adam Fromm, Director of Outreach and Coalitions; Tom Hassenboehler, Chief Counsel, Energy/Environment; Jordan Haverly, Policy Coordinator, Environment; A.T. Johnston, Senior Policy Advisor, Energy; Ben Lieberman, Senior Counsel, Energy; Mary Martin, Deputy Chief Counsel, Energy & Environment; Alex Miller, Video Production Aide and Press Assistant; Brandon Mooney, Deputy Chief Energy Advisor; Mark Ratner, Policy Coordinator; Annelise Rickert, Counsel, Energy; Dan Schneider, Press Secretary; Madeline Vey, Policy Coordinator, Digital Commerce & Consumer Protection; Jeff Carroll, Minority Staff Director; Jean Fruci, Minority Energy and Environment Policy Advisor; Rick Kessler, Minority Senior Advisor and Staff Director, Energy and Environment; Alexander Ratner, Minority Policy Analyst; Andrew Souvall, Minority Director of Communications, Outreach and Member Services; Tuley Wright, Minority Energy and Environment Policy Advisor; and C.J. Young, Minority Press Secretary.

OPENING STATEMENT OF HON. FRED UPTON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF MICHIGAN

Mr. UPTON. Good morning, everyone.

Today, we are going to continue our Powering America series by examining the statute that has played an important role in supporting certain electric generating resources over the past 40 years.
Under the law, PURPA provides preferential rate and regulatory treatment to resources known as qualifying facilities, or better known as QFs. These resources include co-generation facilities such as industrial plants and certain small power producers that use renewable resources such as wind and solar. And today’s panel witnesses include folks representing various types of QFs including solar developers, an industrial paper manufacturer, and a municipal waste facility in Grand Rapids, Michigan, that can generate 18 megawatts of electricity by burning solid waste.

Under PURPA, the FERC is tasked with implementing the law in coordination with state regulatory authorities. This framework of cooperative federalism allows for each state to enact and administer its own program within limits established by the federal standards. And, not surprisingly, since each state has different energy needs, resources, and policy objectives, the terms and conditions of each state’s QF policies, indeed, vary. On that point, I would like to welcome the commissioner from Idaho for appearing here today to share her thoughts and perspectives as a state regulator.

The Energy Policy Act of ’05 did make some modest revisions to PURPA. However, the law has largely remained unchanged since 1978. During the intervening decades, tremendous changes have occurred in the electricity industry, a point that is underscored by the DOE staff report that was released last week. The evolution of the industry has occurred in many ways including the development of the electricity markets in the RTO and bilateral regions, the advent of open access transmission policies, and the influence of new lower cost technologies. All of these factors have changed how electricity is generated, transmitted, and used by consumers.

Additionally, it is important to note that renewable sources of energy, particularly wind and solar, have experienced exponential growth in recent years. Last year alone, capacity additions from utility scale renewable resources surpassed the net additions of all other fuel sources combined. There is no question that renewable resources now play a significant role in the nation’s fuel mix and are a major contributor in decreasing U.S. greenhouse gas emissions.

Considering these changed circumstances, this subcommittee must review whether revisions to PURPA are necessary or appropriate. This examination will continue the arguments both in support and opposition to making reforms to PURPA. Among them, certain utilities contend that the PURPA provision requiring utilities to purchase QF energy is outdated and should be modified or repealed. Conversely, QFs argue that PURPA’s mandatory purchase obligation remains a necessary backstop to support renewable energy in parts of the country that are not receptive to such development.

This oversight hearing will be the first step in reevaluating whether the intent and purpose of PURPA is still being met or if it has already been fulfilled. Additionally, today we are going to be looking at what effect the law is having on consumers and repairs in 2017 and beyond.
With that, I want to thank the panel for being here and I will yield to the ranking member of the full committee, Mr. Pallone, for an opening statement.

[The prepared statement of Mr. Upton follows:]

PREPARED STATEMENT OF HON. FRED UPTON

Good morning. Today we continue our Powering America series by examining a statute that has played an important role in supporting certain electric generating resources over the past 40 years. The Public Utilities Regulatory Policies Act (or “PURPA”) was enacted in 1978 in response to the energy crisis during the Carter Administration, and this law was intended to promote energy conversation and support the use of domestic energy, including renewable resources.

Under the law, PURPA provides preferential rate and regulatory treatment to resources known as “Qualifying Facilities” or better known as “QFs”. These resources include cogeneration facilities, such as industrial plants, and certain small power producers that use renewable resources such as wind and solar. Today's panel includes witnesses representing various types of QFs, including solar developers, an industrial paper manufacturer, and a municipal waste facility in Grand Rapids, Michigan that can generate 18 megawatts of electricity by burning solid waste.

Under PURPA, the Federal Energy Regulatory Commission is tasked with implementing the law in coordination with state regulatory authorities. This framework of “cooperative federalism” allows for each state to enact and administer its own program within limits established by the federal standards. Not surprisingly, since each state has different energy needs, resources, and policy objectives, the terms and conditions of each states’ QF policies vary. On that point, I'd like to welcome the commissioner from Idaho for appearing here today to share her thoughts and perspectives as a state regulator.

The Energy Policy Act of 2005 did make some modest revisions to PURPA, however, the law has largely remained unchanged since 1978. During the intervening decades, tremendous changes have occurred in the electricity industry—a point that is underscored by the DOE Staff Report that was released last week. The evolution of the industry has occurred in many ways, including the development of the electricity markets in the RTO and bilateral regions, the advent of open access transmission policies, and the influence of new, lower-cost technologies. All of these factors have changed how electricity is generated, transmitted, and used by consumers.

Additionally, it is important to note that renewable sources of energy, particularly wind and solar, have experienced exponential growth in recent years. Last year alone, capacity additions from utility-scale renewable resources surpassed the net additions of all other fuel sources combined. There is no question that renewable resources now play a significant role in the nation's fuel mix and are a major contributor in decreasing U.S. greenhouse gas emissions.

Considering these changed circumstances, this Subcommittee must review whether revisions to PURPA are necessary or appropriate. This examination will consider the arguments both in support and opposition to making reforms to PURPA. Among them, certain utilities contend that the PURPA provision requiring utilities to purchase QF energy is outdated and should be modified or repealed. Conversely, QF’s argue that PURPA's mandatory purchase obligation remains a necessary backstop to support renewable energy in parts of the country that are not receptive to such development.

Today's oversight hearing will be the first step in reevaluating whether the intent and purpose of PURPA is still being met or if it has already been fulfilled. Additionally, today we will be looking at what effect the law is having on consumers and ratepayers in 2017. With that, I'd like to thank this panel of distinguished witnesses for appearing today and I look forward to your testimony.

Mr. PALLONE. What happened to the green? They got rid of it. [Laughter.]

I am sorry.

Mr. UPTON. Maize and blue.

Mr. PALLONE. Oh, OK.

Mr. UPTON. The block M will be over that.
OPENING STATEMENT OF HON. FRANK PALLONE, JR., A REPRESENTATIVE IN CONGRESS FROM THE STATE OF NEW JERSEY

Mr. Pallone. All right.

Mr. Chairman, a lot has changed in the electricity sector since Congress passed Section 210 of the Public Utilities Regulatory Policies Act in 1978 and more changes are still to come.

However, a number of the goals of PURPA are still valid today, in particular, the goals of increasing competition, encouraging development and deployment of more clean and efficient electricity generation, and ensuring equitable affordable rates for consumers are still important.

PURPA has been successful in encouraging competition, fostering electricity market development, and in bringing new generation and efficiency technologies onto the grid, and as a result, we now have a more competitive and diversified electricity sector.

Of course, PURPA alone is not the only driver of change in the electricity sector. State policies on renewable energy and energy efficiency expanded wholesale markets, connected technological change, growth of natural gas supplies, and changes in consumer expectations and demand are all reshaping this sector. And I expect we will hear a variety of opinions today about the need for further PURPA reform and the direction that any administrative or legislative reform should take.

The Federal Energy Regulatory Commission recently examined these issues at a technical conference and I believe a number of our witnesses participated and even a few members weighed in on that conference, including myself and Ranking Member Rush. And I realize that some of our members believe that the statute needs to be revised, particularly on issues like estimation of avoided costs, the mandatory purchase requirement, and FERC’s definition of a qualifying facility as it relates to the distance between facilities.

However, the Energy Policy Act of 2005 as passed by this committee under Chairman Barton and signed into law by President Bush provided significant changes to Section 210. Those changes allow utilities in competitive areas to avoid the mandatory purchase obligations. The law also provided greater discretion for state utility commissions to establish methods for determining avoided costs and the duration of power purchase agreements. This change allowed states even greater flexibility to address their individual situations. For example, the state of Idaho, which we will hear from today, made radical changes to its standard contract and avoided cost calculation. These are changes that I do not support but they reinforce the fact that many different outcomes are possible under the current PURPA structure.

We will likely hear about the fact that some markets today are saturated with electricity generation. This is due principally or primarily to reduce costs of new generation technologies and the fact that electricity demand is flat in many markets. There is also a real issue in some regions today where competition now exists among different generation assets that are all trying to earn sufficient revenue within markets where rates are stable or falling due to flat demand.
In some areas I suspect there is a reluctance to add new, more efficient cleaner energy resources into areas where existing fossil and nuclear generation assets are struggling financially. But when Congress made the decision to encourage more competition in the development of wholesale markets, there were bound to be winners and losers in those markets to the larger benefit of the consumer.

Consumer preferences, state policies, technological change, and economic trends are favoring renewable resources over traditional fossil and nuclear generation, and this transition is bringing us a clean and more efficient grid and these are positive developments and I would not want to see this committee reversing course on competitive market development without a much more serious and longer consideration of the impacts of such a move away from competition.

FERC has authority to make some changes in the implementation of PURPA. The recent technical conference provided the commission with information to evaluate the effectiveness of its implementation and enforcement of PURPA.

So we have an excellent panel of witnesses here this morning. I look forward to hearing their testimony. Thank you again, Mr. Chairman, for holding this important hearing and for working with us on this series of bipartisan hearings on the current status of the electricity sector.

And I did like the green better. Sorry. Well, actually, you liked the green better.

Mr. UPTON. So Oregon green is gone.

[Laughter.]

The chair would recognize the——

Mr. PALLONE. Just trying to go blue here.

Mr. UPTON. It was a nice win over Florida. Sorry they are not here today. The chair would recognize the chair of the full committee, gentleman from Oregon, Mr. Walden.

OPENING STATEMENT OF HON. GREG WALDEN, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF OREGON

Mr. WALDEN. I thank the gentleman.

Nearly 40 years ago, as we have all heard, Congress passed the Public Utilities Regulatory Policies Act, commonly known as PURPA. As many of you are aware, this law was passed during the time when the country was overly dependent on foreign supplies of energy, resulting in national energy shortages and economic instability. And in response to these challenging circumstances, Congress passed PURPA with the goal of promoting energy conservation, and increasing domestic energy supplies.

Now that PURPA has been in place for multiple decades, we can see how it has helped transform the U.S. energy sector, bolstered renewable energy, and reduced greenhouse gas emissions. Gone are the days of Americans relying heavily on overseas sources of energy and unstable global markets to meet energy needs. Instead, the country now has access to many forms of abundant domestic energy which has been spurred by innovative technologies and competitive energy markets.

In passing PURPA, Congress took the first steps toward competition within the electricity markets by allowing electricity genera-
tion to be independent of regulated monopolies for the first time. Since then, Congress and FERC have continued to take actions to increase competition, resulting in tremendous benefits for consumers across the country. We on the committee want to continue down the same path of increased competition and innovation. Our aim is to strengthen energy markets and encourage innovation throughout the electricity sector, giving consumers more choice and greater control over their energy decisions while also benefitting the environment.

Today’s hearing gives us the opportunity to look at PURPA with fresh eyes and evaluate what effect it is having on evolving electricity markets and the modern-day consumer. Given the fact that PURPA was written nearly 40 years ago and the U.S. electricity system is undergoing significant transformation, now is the time for the committee to review PURPA and its associated impacts. This review includes discussing the original intent of specific PURPA provisions and determining if these provisions are still working successfully today. For example, in today’s hearing we will review the requirements connected to the mandatory purchase obligation, the effectiveness of the 1-mile rule when designating qualifying facilities and the various methods states are using to calculate avoided costs.

The committee understands that many stakeholders in the electricity sector are closely following potential PURPA reforms. In fact, I know this is true for my constituents in eastern Oregon where we have more than 100 qualifying facilities operating as a direct result of PURPA. So in addressing this topic, we want to make sure that all stakeholders, all of them, have an opportunity to be heard, which is why we are holding the hearing today and why we will continue to engage proactively with all stakeholders, moving forward.

In all that we do on the Energy and Commerce Committee, we strive to focus on the needs and interests of American consumers. When we are successful in this pursuit, I am confident that everything else will find its proper place.

With that, I look forward to the remainder of the hearing and better understanding how PURPA is affecting consumers across the country.

And with apologies, I know we have a couple of hearings going on so I’ve got to go to another one and be back and forth. But thank you for your testimony. It is most enlightening and helpful in our work, and I yield back.

[The prepared statement of Mr. Walden follows:]

PREPARED STATEMENT OF HON. GREG WALDEN

Nearly 40 years ago, Congress passed the Public Utilities Regulatory Policies Act, now commonly referred to as PURPA. As many of you are aware, this law was passed during a time when the country was overly dependent on foreign supplies of energy, resulting in national energy shortages and economic instability. In response to these challenging circumstances, Congress passed PURPA with the goal of promoting energy conservation and increasing domestic energy supplies.

Now that PURPA has been in place for multiple decades, we can see how it has helped transform the U.S. energy sector, bolstered renewable energy, and reduced greenhouse gas emissions. Gone are the days of Americans relying heavily on overseas sources of energy and unstable global markets to meet their energy needs. In-
stead, the country now has access to many forms of abundant domestic energy, which has been spurred by innovative technologies and competitive energy markets.

In passing PURPA, Congress took the first step towards competition within the electricity sector by allowing electricity generation to be independent of regulated monopolies for the first time. Since then, Congress and FERC have continued to take actions to increase competition, resulting in tremendous benefits for consumers across the nation. We on the committee want to continue down this same path of increased competition and innovation. Our aim is to strengthen energy markets and encourage innovation throughout the electricity sector, giving consumers more choice and greater control over their energy decisions, while also benefiting the environment.

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In all that we do on the Energy and Commerce Committee we strive to focus on the needs and interests of American consumers. When we are successful in this pursuit, I am confident that everything else will find in its proper place. With that, I look forward to the remainder of this hearing and to better understanding how PURPA is affecting consumers across the nation.

Mr. Upton. And we have a bill on the floor.

Mr. Walden. And we have a bill on the floor and a Korean briefing and oh, lots going on.

Mr. Upton. Gentleman’s time is expired. Any on the minority side wishing at this time? Seeing none, we will go right then to the testimony by our witnesses.

We are joined first by Mr. Frank Prager, Vice President of Policy and Federal Affairs for Xcel Energy. Welcome. All of your testimonies are made part of the record and if you would take no more than 5 minutes to give a summary of that, that would be great and we will start with you.

Thank you. Welcome.

STATEMENTS OF FRANK PRAGER, VICE PRESIDENT, POLICY AND FEDERAL AFFAIRS, XCEL ENERGY; TODD GLASS, COUNSEL, SOLAR ENERGY INDUSTRIES ASSOCIATION; KRISTINE RAPER, COMMISSIONER, IDAHO PUBLIC UTILITIES COMMISSION; STEPHEN THOMAS, SENIOR MANAGER, ENERGY CONTRACTS, DOMTAR PAPER COMPANY; TERRY KOUBA, VICE PRESIDENT, IOWA OPERATIONS, ALLIANT ENERGY; DARWIN BAAS, DEPARTMENT OF PUBLIC WORKS FOR KENT COUNTY, MICHIGAN

STATEMENT OF FRANK PRAGER

Mr. Prager. Thank you very much, Mr. Chairman.
Members of the committee, my name is Frank Prager. I am vice president of policy and federal affairs at Xcel Energy. I am pleased to be here today to talk to you about PURPA and PURPA reform.

Xcel Energy is a public utility holding company headquartered in Minneapolis, Minnesota. We serve parts of eight Western and Midwestern states including Denver, where I am from.

We are the nation’s number-one utility provider of wind energy. We have held that distinction for a dozen years. Xcel Energy currently has over 6,700 megawatts of wind on its system and is currently in the process of adding an additional 3,400 megawatts of wind.

Renewable energy is a big part of our energy portfolio. We are also in the process of decarbonizing our electric grid. Xcel Energy has already reduced its CO$_2$ emissions by 30 percent from 2005 levels and are on a path, if we continue to see technological advancement in the renewable energy area, to achieve a 60 percent reduction by 2030.

Our customers like renewable energy. They like the fact that we are decarbonizing our electric grid. But they love the fact that we are able to do it at a low price. We actually are now in the process of implementing a strategy we call steel for fuel under which we are actually reducing our carbon dioxide emissions while at the same time reducing our customers' energy rates. And as I say, our customers are very fond of that strategy.

As strong proponents of cost-effective renewable energy, Xcel Energy believes it is time for Congress to reform the outdated PURPA statute. As described in my written testimony, the energy market fundamentals that led to the adoption of PURPA no longer exist. Today, we live in an era of relative energy abundance rather than the energy crisis that existed at the time PURPA was first adopted. Customer energy use is flat. Renewable energy is no longer a niche technology but a growing part of our energy portfolio. Robust wholesale energy markets and least-cost resource planning have facilitated market-based acquisition of energy.

PURPA was designed to address energy challenges of the 1970s that no longer exist and are inconsistent with the modern energy marketplace. Under PURPA’s must take provisions, QFs can displace energy from existing more efficient power plants, thereby raising costs for our customers. QFs can force utilities to take power outside of the state utility planning processes. Those are the processes that states use to assure a reliable and cost-effective energy system. For example, in Colorado, a QF developer informed Xcel Energy that it had intended to develop 19 separate QF facilities, each of 80 megawatts.

Although Colorado PUC regulations are clear that those QFs must participate in the resource planning process, this QF developer declined to do so. It demanded that we enter into a long-term contract for its contemplated 1,520 megawatts of QF energy. Litigation with that developer is ongoing. However, its claims demonstrate one of the key problems associated with PURPA. QFs can operate outside state resource planning and thus force electricity consumers to pay for energy they do not need.

PURPA can also interfere with transmission planning. That same QF developer has proposed to put 480 megawatts, almost a
half a gigawatt, of its power in a remote location far from our load centers in an area where we do not have adequate transmission capacity and an area where the existing transmission capacity is subscribed by existing solar facilities that are under contract to Xcel Energy.

If this QF is successful in putting its power to Xcel Energy, we will be required to spend millions of dollars in transmission upgrades and will have to work in order to make sure that our existing solar facilities have access to the electricity marketplace. The other problem with PURPA, which is one the chairman identified, is the ability of some QFs to game the PURPA regulations in particular with regard to the 1-mile rule. Under its terms, the QFs are limited to 80 megawatts and PURPA—and FERC has implemented that 80 megawatt limit through the 1-mile which requires the two QFs be separated by at least a mile.

Unfortunately, FERC has allowed some developers to circumvent this rule. In our Texas service territory, FERC found two separate segments of a larger wind project with a single owner and a single interconnection—literally, one project considered to be two separate QF projects because the developer had made certain that no two wind turbines from that project were located within a mile of one another. Thus, a project that greatly exceeded PURPA’s 80 megawatt limit was able to force Xcel Energy to buy power from it at the avoided cost rate.

We encourage Congress to consider legislation that would help address these and other problems with PURPA. Even without PURPA, the renewable energy market has never been stronger and QFs would have the opportunity to compete for a growing piece of the renewable energy pie.

Thank you again. I would be happy to answer any questions that you have.

[The prepared statement of Mr. Prager follows:]
Chairman Upton, Ranking Member Rush, and members of the Subcommittee, thank you for the invitation to speak at this important hearing.

My name is Frank Prager, and I am Vice President of Policy and Federal Affairs for Xcel Energy, a public utility holding company serving 3.5 million electric customers and 2 million natural gas customers through four utility subsidiaries. Headquartered in Minneapolis, we serve parts of eight Western and Midwestern states, including the Twin Cities of Minnesota, Denver and the Colorado Front Range, and the Texas Panhandle and Southeastern New Mexico. We have a balanced energy mix that includes natural gas, coal, nuclear and, as I’ll discuss in more detail below, renewables.
I am pleased to join you today to talk about our perspective on the Public Utility Regulatory Policies Act of 1978, or PURPA. I speak as a representative of a company dedicated to renewable energy. Xcel Energy has been the number one utility provider of wind energy for a dozen years. We currently have nearly 6,700 MW of wind on our system and are in the process of adding nearly 3,400 MW. Fully 65% of these existing and planned resources are owned by independent power producers. We are also a leading solar provider and expect to add 900 MW of solar to our already growing solar portfolio. Through these wind and solar additions, we are decarbonizing our energy generation fleet. We have already reduced carbon dioxide emissions by 30% from 2005 levels and are on track to achieve a 45% reduction by 2021. Our CEO Ben Fowke has recently announced that, with continued advancement in renewable technology and the right public policy, we can achieve at least a 60% reduction in CO2 emissions by 2030.

Exhibit A provides more information about Xcel Energy and its renewable energy leadership.

This remarkable achievement rests on our company’s commitment to renewable energy. However, very little of our growing renewable portfolio arises as a result of PURPA; rather, our renewable portfolio was built largely as a result of state policies designed to encourage renewable development.

As my testimony will discuss, PURPA represents an energy policy from another time and is inconsistent with the realities of today. PURPA was adopted almost 40 years ago to encourage states and utilities to grow domestic energy resources. Today, however, PURPA incentivizes developers to build generation that is not needed and site it in locations where it provides no value to the grid. PURPA thwarts the opportunities of other independent power producers. PURPA also allows developers to circumvent state siting rules and pursue avoided
cost pricing constructs that are contrary to the best interests of utilities’ customers, the people who ultimately pay these higher costs in their electric bills.

As detailed below, we are seeing these problems first hand. PURPA threatens to impose higher costs on our customers, disrupt our electricity planning and operations, and impede state energy policies. Ironically, it does so just as the renewable energy marketplace has never been stronger or provided greater opportunity for renewable energy developers who are willing to compete to provide us with the renewable energy we use to serve our customers. In light of its inconsistency with today’s electricity marketplace, it is time for Congress to take action to address PURPA’s misplaced incentives.

1. Congress passed PURPA in 1978 to address energy issues that no longer exist.

In 1978, during the Carter Administration, Congress passed a series of statutes in response to the Arab oil embargo and the nation’s overdependence on foreign energy. PURPA was one of those statutes. It was designed to help the nation achieve energy independence by encouraging the development of small power production and cogeneration facilities. Under Section 210 of PURPA, Congress required electric utilities to purchase power from “qualifying facilities” (QFs). QFs are either cogeneration facilities or small power production facilities that use renewable energy (including solar, wind, biomass or waste) to generate electricity and have a generating capacity of less than 80 MW. Under PURPA, QFs have the legal right to force utilities to purchase their output at a price equal to the avoided cost of electricity.

PURPA was intended to overcome disincentives on the part of the states and utilities to embrace competition. Over at least the last two decades, these disincentives have virtually disappeared as states have embraced policies that promote utilities’ use of competition to procure needed
generation resources (both renewable and non-renewables) and as FERC has pursued open access policies that allow independent power producers to transmit energy to utilities—even outside of organized markets. As a consequence, energy market fundamentals have changed dramatically from the situation in 1978. Today:

- We live in an era of relative energy abundance rather than an atmosphere of energy crisis as existed when PURPA was first adopted;
- We also live in an era of energy efficiency where customer energy use is flat or declining despite a growing economy;
- There is a mature independent power production sector, which provides 39% of the energy produced in the country;
- Renewable energy provided 16% of the electricity consumed by Americans in 2016 and is no longer a niche technology requiring forced purchases to remain viable;
- The amount of renewables in the country is only expected to grow, and grow rapidly, as states continue to pursue renewable energy and decarbonization goals.
- There are robust wholesale energy markets throughout much of the country, facilitating market-based acquisition of energy; and
- For utilities operating in states that do not have wholesale markets, most states require utilities to use competitive bidding or least-cost resource planning in the acquisition of energy resources.

See FERC Order 888, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Docket No. RM95-8-000 (April 24, 1996)
PURPA was designed to address the long-past energy challenges of the 1970s. However, unlike disco balls or shag carpeting, PURPA has not gone away. As I discuss below, it continues to impose significant, unnecessary burdens on the nation’s electricity consumers and the electricity markets.

2. PURPA’s "must-take" provisions distort the function of the electricity markets for both independent power producers and customers. Neither utilities nor state regulators can take steps to anticipate or avoid these consequences: the QF has the ability to appear at any time and force a utility to take its power outside of the state utility planning process. State resource planning is critical to ensuring reliable energy and maintaining reasonable customer bills. States also oversee competitive procurement processes that provide an avenue for independent power producers to obtain competitively priced long-term contracts for their output. The right of a QF under PURPA to force a utility to take its output can interfere with these important state functions.

This interference is especially important with renewable energy. State policies are perhaps the most important drivers of the growth in the nation’s renewable energy portfolio. However, the ability of utility systems to integrate renewable energy is neither unlimited nor free, and states’ planning processes are the appropriate forum for weighing the benefits of adding renewable energy against the costs of integration.

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2 In some states, those renewable standards are quite aggressive. For example, the renewable portfolio standards in our Colorado and Minnesota service territories are generally 30% by 2020.
A real-world example illustrates this problem. In Colorado, Xcel Energy is engaged in a resource planning process to fill its customers' energy needs. As part of this process, the Colorado Public Utilities Commission (PUC) is considering how to meet customer energy needs and take advantage of low-priced renewable energy incentivized by federal tax credits.

In 2016, in the midst of that process, a QF developer informed Xcel Energy that it intended to develop 11 solar and eight wind QFs, each with a capacity of 80 MW and “put” the output of those facilities to Xcel Energy’s Colorado affiliate, that is, to use PURPA to force Xcel Energy to purchase that output. Although Colorado PUC regulations are clear that QFs must participate in the state resource planning process and can be selected only after winning a competitive bid, this developer demanded that Xcel Energy enter into long-term contracts for power from its contemplated 1,520 MW of QF resources outside of the state processes. Further, the developer demanded that Xcel Energy pay for the energy from its facilities at a price determined by a calculation of avoided cost rather than through a competitive-bidding process. The Colorado PUC denied the developer’s demands, and the developer appealed to the federal courts.

Litigation over this developer’s proposal is still pending. The developer’s claims, however, demonstrate one of the key problems associated with PURPA: utilities can be forced to take energy they do not need and outside of state resource planning and procurement processes. If this developer were to prevail, it would render the state’s bid-based procurement process moot; the amount of energy that the developer proposes to put to us far exceeds our customers’ incremental energy needs. The proposal would also deny the state of the opportunity to address the potentially significant integration costs associated these intermittent QFs that are necessary to maintaining system reliability.
This developer has attempted to disrupt efficient and effective state resource procurement processes and impose higher costs on customers. Where state-run resource planning and competitive procurement processes exist, the rights to QF puts should be subordinate to the state process. States should be able to identify their own resource policy goals and the types of resources that can best achieve those goals, taking into consideration reliability and cost. Competitive procurement processes will provide a level playing field for all resource types, ensuring that customers do not pay above market for resources simply because they are QFs. Further, competitive processes allow all developers the opportunity to meet our resource needs and do not allow QFs to erect barriers to participation by other developers.

The consequences of unneeded QF development hurt both customers and other independent developers. For independent power producers, energy from an unneeded QF facility can displace energy that a utility might otherwise have procured from an independent generator under contract to the utility. Thus, an independent generator may be unable to realize the full benefits of its energy contract. For customers, unneeded QFs can raise customer costs if: (1) the utility has to pay a curtailment fee to an independent generator for energy the generator was unable to produce due to the QF’s output; or (2) the QF energy displaces energy that would have been produced by utility-owned generating resources, forcing customers to pay for the cost of underutilized assets.

3. PURPA can allow QFs to interfere with the efficient operation of the transmission system and wholesale markets.

Transmission planning has developed over the last twenty years as a result of both state law and FERC orders. It creates the backdrop for modern energy markets while ensuring system reliability. Although transmission providers have the responsibility for ensuring that the
transmission system accommodates the needs of load and generating resources, under typical resource procurement processes the cost of transmission required to deliver generator output to customers is taken into account in identifying the most cost-effective resources.

PURPA, however, undermines these processes. Because QFs can force their way onto the electric system at the time and location of their choosing, they can site their facilities in locations where transmission capability may be insufficient to deliver the QF’s power to customers. As a result, utilities could be forced to make significant investments in transmission upgrades to enable delivery of QF energy.

The situation with the Colorado developer highlighted above demonstrates this problem. Of the 1,520 MW of wind and solar power that the developer is attempting to put to us in Colorado, 480 MW of that power is proposed for a remote area of the state, hundreds of miles from load centers. In addition, all of the transmission capability in that area is already fully subscribed by five solar facilities that are already under contract. This developer’s QF projects could: (1) cause our customers to pay potentially hundreds of millions of dollars in transmission upgrades to deliver the QF’s energy; and (2) cause us to curtail the output from the five existing solar facilities already in this area.3

In other words, QF siting decisions can also drive added energy costs for customers, yet PURPA does not create incentives for QFs to consider the costs of their siting decisions on customers.

4. PURPA incentivizes QFs to promote avoided cost pricing policies that are not in the best interest of customers

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3 Indeed, we have experienced situations in Texas where QFs putting to our Texas affiliate have displaced pre-existing resources that were selling to us under contract due to lack of transmission capability.
Rules adopted by FERC to implement PURPA allow QFs to choose whether to be paid on an “as available” basis or pursuant to a long-term contract, with pricing under the long-term contract established as of the day the QF’s ability to put to the utility arises. States have the authority to specify how avoided cost rates are determined for their utility systems.4

For a variety of reasons, these methodologies can vary from the results achieved in the market. The calculation methodologies can use the wrong proxy for avoided costs (e.g. a higher priced utility resource instead of a lower priced IPP proxy) or make incorrect assumptions regarding the way in which the market would function.5 As a result of these problems, this calculation methodology can give the QF a price for its power well above the price it could receive from a competitive bid.

Further, under FERC’s rules, avoided cost pricing under a long-term contract must reflect avoided cost at the time the QF establishes the right to put that energy to the host utility. This requirement incentivizes QFs to impose a purchase obligation during time periods when markets are experiencing pricing anomalies. Our Texas utility experienced this problem first hand when a QF attempted to unilaterally impose a put to our utility based on anomalous pricing. After years of litigation at FERC and in state and federal courts, this QF ultimately withdrew its claim. Had we been forced to accede to this QF’s demands, our customers would have paid tens of millions of dollars in excessive costs.

4 As I discuss in this testimony, bidding is one of the best ways for a state to determine the avoided cost and set the QF price. However, FERC has issued declaratory orders that have caused uncertainty around the use of bidding. See See Hydrodynamics Inc., 146 FERC ¶ 61,193 (2014) (“Hydrodynamics”) and Windham.

In addition, siting decisions by QFs that are unmoored from market fundamentals create market risk for customers. In the organized energy markets, it is possible for pricing at a generator’s location to become negative. That situation occurs when there is too much generation in a specific location that cannot be moved out to serve load due to transmission constraints. When prices turn negative, generators pay to have the system take their output rather than being paid by the system for the energy they deliver to the grid. The intent behind negative prices is to send economic signals to generators both letting generators know where to site (and not to site) new facilities and on an operational basis letting generators know when they should reduce their output to avoid having to pay the market to take their energy.

Unless QFs are exposed to real-time market pricing, they have no incentive to avoid the consequences of siting in a generation pocket and producing energy when prices are negative. If QFs are insulated from the pricing consequences of their decisions, customers bear the risk of negative prices even though neither the utility nor the customers can control the QFs’ behavior.6

The best mechanism for ensuring that QF avoided cost pricing protects the interest of customers is to require that such pricing be established through competitive market forces, and payment based on prices that reflect the competitive forces within organized markets.

5. FERC rules implementing PURPA incentivize renewable QFs to game the 80 MW QF limit in PURPA

Under PURPA, a renewable energy power production facility can be a QF provided it “has a power production capacity which, together with any other facilities located at the same site (as

6 In Texas, as a result of protracted litigation in the 5th Circuit Court of Appeals, our Xcel Energy affiliate pays QFs on the basis of market pricing. Without this litigation, our customers would have been subject to significant costs associated with QFs that have chosen to locate their facilities in a pocket that has abundant generation relative to load needs. We calculate that this cost would have been approximately $5495 per year for every megawatt of QF capacity.
determined by the Commission), is not greater than 80 megawatts.” 16 U. S. C. § 796 (17)(A). Pursuant to this section, FERC adopted the “one-mile rule,” which provides that facilities are considered to be located at the same site as long as generating facilities are located within one mile of one another. Many QFs have attempted to “game” this system to allow them to build larger facilities and force utilities to purchase their output. Wind farm developers use the one-mile rule to shoehorn wind farms that in reality exceed the 80 MW threshold of PURPA into multiple facilities each of which ostensibly meets the 80 MW threshold.

For example, in a case involving our Texas utility, FERC found two segments of a wind project (one 80 MW and one 40 MW) to be separate QF projects because the developer had made certain that no wind turbine from one segment was located within one mile of a turbine from the second segment. FERC made this finding despite the fact that the QF developer had treated the segments as a single project: each segment relied on the same point of interconnection to the transmission grid, was developed by the same entity, and was publicly discussed as a single project. The commonalities of these projects clearly demonstrated that they were in fact a single facility for which turbine spacing had been manipulated in order to allow them to meet the one-mile rule. See DeWind Novus, LLC. 139 FERC ¶ 61,201 (2012). See also Northern Laramie Alliance 138 FERC ¶ 61,171 (2012).

By its terms, PURPA was supposed to encourage the development of small projects. As this case demonstrates, projects comprised of hundreds of generating turbines with capacities far in excess of 80 MW are gaming FERC’s rules in order to be classified as multiple QFs. These large projects are attempting to circumvent competitive acquisition, and FERC is encouraging them by elevating the form of its arbitrary one-mile rule over the substance of the transaction.
6. **PURPA’s Section 210(m) exemption should apply to QFs of all sizes**

Through a series of orders stretching back more than two decades, FERC has attempted to transform the utility industry. It has created organized RTO and ISO markets that require companies to bring market discipline to wholesale energy transactions. It requires utilities to offer open access transmission and market-based rates. Working with states, FERC has established the framework that created the independent power industry and allowed third-party players the opportunity to develop gas and renewable generating assets that can sell their power to utilities and customers. Along with state initiatives to support renewables, FERC’s rules have accomplished most of the goals of the PURPA—a robust IPP industry, market discipline, a diverse power supply and renewable energy development.

In recognition of this fact, and in light of some of the abuses of PURPA I have discussed today, Congress added Section 210(m) to Federal Power Act in the Energy Policy Act of 2005. Section 210(m) authorizes utilities in RTO markets to obtain an exemption from PURPA if the QF has nondiscriminatory access to the market. FERC adopted regulations implementing Section 210(m) that provide a safe harbor for QFs with capacity of less than 20 MW by creating a rebuttable presumption that such QFs do not have nondiscriminatory market access.

While helpful, Section 210(m) is still inadequate: It does not apply to states in the West or South or other states that have not joined organized markets. Further, even in organized markets, FERC’s 20 MW safe harbor still allows relatively large resources to avoid the discipline of the market and put their energy to the utility. For example, in Minnesota, FERC upheld the safe harbor protection for an 18-MW hydro facility that serves the needs of over 14,000 homes. The owner of this facility is a large renewable energy developer with the sophistication and resources...
to bid the power into the MISO market. However, it sought instead to put the power from the hydro facility to Xcel Energy under PURPA seeking higher avoided cost pricing, and FERC agreed with the QF. In other words, despite Section 210(m), this sophisticated market player sought to use PURPA to force Xcel Energy to purchase its power from a relatively large facility—that had already been participating in the market for years—rather than competing in the MISO wholesale market.\(^7\)

4. Congressional action can help solve the problems of PURPA.

Through this hearing, the 115\(^{th}\) Congress is taking the first step toward addressing PURPA and its continuing impact on the energy marketplace. We encourage Congress to consider legislation that would help address these problems and improve the efficiency and certainty of the nation’s electricity supply process. Here are several options that would solve most or all of the problems created by PURPA:

- **Repeal Section 210 of PURPA.** As indicated in my testimony, Section 210 of PURPA is a creature of another time, and the principal policy drivers that led to its adoption are no longer in place today. Through its rulemakings, FERC has created robust energy markets, and IPP development opportunities exist largely due to state policies favoring competitive bidding and the development of renewable resources. More importantly, as Xcel Energy’s experience indicates, we live in the golden age of renewable energy. QF developers would have plenty of opportunities to develop competitive renewable energy projects even without the PURPA forced purchase requirement. Congress could solve

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\(^7\) Note that since FERC’s order allowing it to put to Xcel Energy, the hydro facility has not attempted to execute a contract with us.
PURPA’s many problems by simply repealing the provisions of Section 210 of PURPA relating to small power producers.

- **Expand the exemptions from PURPA’s forced purchase requirement if QFs have reasonable market opportunities.** As I discussed in detail above, one of the larger issues with PURPA is that it undermines state resource planning and procurement processes and does not recognize that QF developers have ample opportunities to compete in today’s markets. Congress can help address this problem by ensuring that utilities are relieved of the mandatory purchase obligation where: (1) their state regulators undertake a least-cost resource planning or competitive solicitation process or have concluded that the utility does not have a need for the additional energy or capacity from a QF to meet its obligation to serve customers in the public interest; and (2) the utility participates in an independently administered, voluntary, auction-based market, without regard to whether the market is administered by a Regional Transmission Organization or an Independent System Operator.

- **Prevent QF abuses of PURPA.** Congress may choose to direct FERC to develop rules to prevent abuses of PURPA. Among other things, PURPA reform legislation should: (1) remove the 20 MW safe harbor for QFs imposed under FERC’s rules implementing Section 210(m) under EPAct 2005; (2) require unsolicited QFs to bear the costs of transmission upgrades necessary to deliver their output to load; (3) require QFs to bear the cost of negative pricing in wholesale markets; (4) set avoided cost pricing through market forces; and (5) direct FERC to prevent the abuses of the one-mile rule.
Thank you again for the opportunity to be with you today. I would be happy to answer any questions.
Mr. UPTON. Thank you.

We are joined next by Todd Glass, counsel to the Solar Energy Industries Association. Welcome.

STATEMENT OF TODD GLASS

Mr. GLASS. Thank you.

Mr. Chairman, distinguished members of the subcommittee, good morning. My name is Todd Glass. I am an energy lawyer who represents developers and financiers of independent solar-powered projects and the solar industry in energy regulatory matters. I am delighted to appear on behalf of the Solar Energy Industries Association with regard to PURPA, its original objectives and its relevance to customers today.

SEIA is the national trade organization for the solar industry in the United States, representing more than a thousand organizations that promote manufacture, install, and support the development of solar energy around the United States. SEIA seeks to expand markets, remove market barriers, strengthen the industry and educate the public on the benefits of solar energy.

PURPA's original objectives were to do two primary things: to increase the diversity of supply by type fuel source, size, and ownership, to strengthen national energy security in the nation's electric supply. Fuel diversity remains essential to our national energy security and PURPA continues to provide the means to ensure the increased diversity of supply, particularly with regard to fuel-less generation resources.

PURPA's second major contribution was to create competition that forces prices down, that benefits consumers by eliminating utilities' anti-competitive actions against competitive generation. Independent generation puts downward competitive pressure on prices and benefits consumers by reducing the cost of electricity. As new technology such as solar are deployed, the price of delivering power to consumers will continue to decrease. Those two objectives have yet to be fully achieved. PURPA remains an essential federal legislation underpinning both diversity as well as competition in the electric power industry.

The U.S. solar industry can compete. As outlined in my testimony, solar energy has experienced a rapid decline in cost over the past decade to become a true economic alternative and competitor to traditionally-owned utility generation. Solar prices have become competitive with wind and natural gas fuel generation. Solar installations, however, are principally owned by independent power producers who, through innovation and persistence, have been able to withstand the competitive pressures today to build and finance their project.

With only a fraction of those installations actually contracted for under PURPA's must purchase obligation, PURPA as a whole remains an essential backstop against anti-competitive conduct for all independent power and a backstop for financing these independent power projects.

Electric utilities in the United States are among the most enduring long-lived monopolies in the United States. As Congress recognized in 1935, electric utilities must be regulated in order to protect the public interest.
In 1978, Congress created PURPA. PURPA is not an environmental law. Rather, its provisions provide for energy conservation in a unique federalism system that eliminates discrimination against co-generators and small power producers, which you correctly called QFs, by requiring interconnection, wielding of their power, and purchasing their power at a price no greater than the incremental cost of buying that electric power from alternative sources.

With its passage, PURPA became the bedrock federal law ensuring competition in wholesale power markets. Soon after FERC promulgated the regulations, utilities started fighting PURPA and its mandates. Indeed, 40 years later, they are still fighting its mandates. Why? Utilities would simply prefer not to have to buy generation from small diverse QFs that don’t fit neatly within their plans. They would rather build and rate base larger generation facilities and maintain a controlled vertically-integrated monopoly or buy through power purchase agreements through our RFPs. They have never liked PURPA and they still don’t like PURPA today. Solar power PURPA projects are not a real problem.

As shown in my testimony, in 44 states solar energy in the last year totaled less than 5 percent of the total energy used and in a vast majority of states it is less than 1 percent. Of that amount of total installed solar capacity, only 20 percent is actually based upon a PURPA must-purchase obligation. Due to land usage and power density, solar power is not an industry that is abusing FERC’s 1-mile rule. Notwithstanding the penetration, our industry is putting competitive pressures on energy prices and benefitting those consumers by forcing the utilities to look at lower cost power.

So PURPA is about diversity: fuel size, type, and ownership and competition. U.S. solar industry is here to compete, to create jobs, and investment and create tax base in both urban and rural America and to make the electric grid more diverse and secure. SEIA strongly encourages Congress to continue supporting competition by ensuring independent generators like solar can compete.

Thank you, and I look forward to your questions.

[The prepared statement of Mr. Glass follows:]
Testimony of
Todd G. Glass
Wilson Sonsini Goodrich & Rosati, P.C.
on behalf of the
SOLAR ENERGY INDUSTRIES ASSOCIATION
Before The
United States House of Representatives
Committee on Energy and Commerce
Subcommittee on Energy
Hearing entitled “Powering America:
Reevaluating PURPA’s Objectives and its Effects on Today’s Consumers”
September 6, 2017
Mr. Chairman, Ranking Member Rush, and Members of the Subcommittee:

On behalf of Solar Energy Industries Association (SEIA), thank you for the opportunity to testify on the Public Utility Regulatory Policies Act of 1978 (PURPA), its original objectives, and its relevance to consumers today. SEIA represents all organizations that promote, manufacture, install and support the development of solar energy and works with its 1,000 member companies to champion the use of clean, affordable solar power in America by expanding markets, removing market barriers, strengthening the industry and educating the public on the benefits of solar energy. SEIA is the national trade association for the solar industry in the United States and, in 2016, 1 out of every 50 new jobs added in the U.S. in 2016 came from solar and nearly $23 billion was invested in U.S. solar installations. Since 2013, U.S. solar industry employment has grown by at least 20% every year. More than 26,000 jobs are expected to be added in 2017 and over the next five years, the solar industry will invest more than $86 billion in the U.S. economy. To continue on this path of growth, it is essential that PURPA be maintained as backstop federal authority.

I have worked across the United States for more than twenty years in support of independent power producers in their efforts to compete with utilities to offer the lowest-price power to consumers within states across the country. Since 2005, I have led one of preeminent independent power project development and finance practices focused on solar power development, including utility scale and residential installations. I also teach Energy Project Development and Finance at University of California, Berkeley School of Law. Based on my experiences and knowledge gained in all of these roles, I can unequivocally state that PURPA

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1 This testimony represents the position of SEIA as an organization, but do not necessarily reflect the views of any particular member with respect to any issue. In this testimony, I present the views of the solar industry, as represented by SEIA, not those of Wilson Sonsini Goodrich & Rosati, P.C. or any of its individual clients.

and its protections are fundamental to the ability of independent power, including the solar industry, to compete and thrive throughout the United States.

PURPA first enabled non-utilities to own and operate certain cogeneration and small renewable power generation facilities by requiring utilities to interconnect, transmit power, and offer to purchase the output of such plants at the utility's avoided cost. PURPA thereby created the first competition in the electric power industry and enabled a substantial influx of non-utility generators. PURPA is an essential piece of federal legislation that backstops competition by ensuring that competition from independent generators will continue to put downward pressure on energy prices, while simultaneously supporting the important statutory goals of fuel diversity and national security. If the goal of this Subcommittee is to continue to rely on independent competitors to enter the electric market and place additional downward pressure on cost-of-service rates, PURPA's mandatory purchase standard should be strengthened, not weakened.

I. PURPA REMAINS ESSENTIAL TO INDEPENDENT GENERATION AND COMPETITION

In the context of the energy challenges facing the United States in the 1970s, Congress recognized that utility-driven resource procurements were insufficient to meet national energy security objectives, as the utilities had not achieved sufficient diversity with respect to fuel type, size, and ownership. There existed no market for independent or competitive generation that would lead to lower prices for consumers. During the early years of PURPA, significant progress for independent generation was made through the installation and development of cogeneration plants across the country. In the past decade, newer technology-based generation, like solar, has achieved cost parity with utility-owned generation sources. As technology and

scale of solar continues to develop, the price for solar generation continues to decrease and with these price decreases, independent power producers place additional pressure on a utility to reduce the price to serve consumers. Independent power producers are finally emerging as true competitors to monopoly-regulated utilities, but still require PURPA’s backstop protections to ensure that competition can continue to thrive in the electric generating industry.

A. Historical Perspective

In 1973, prior to the passage of PURPA, the Supreme Court ruled on a competitor’s antitrust dispute seeking a remedy for a utility’s refusal to sell power at wholesale to competitors and refusal to provide transmission service to competitors. The Supreme Court found that such practices violated the antitrust laws because the utility did not provide a competitor with access to a facility essential to engaging in business. Four years later, Wheelabrator-Frye Corporation, another company desiring to compete, was denied the opportunity to sell power to a utility. Wheelabrator’s frustration and Senator John Durkin’s willingness to take up the competitive cause led to PURPA’s passage. Durkin was supported by manufacturers that were interested in installing their own generation as a means to ‘avoid the high costs of utilities’ over-budget reactors.’ These issues, paired with the nation-wide energy crisis, led Congress to pass PURPA

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4 See Otter Tail Power Co. v. United States, 410 U.S. 366 (1973); see also Small Power Production and Cogeneration Facilities: Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, FERC Stats. & Regs. ¶ 38,128 at 38,868 (1980) ("Order No. 69") (explaining that prior to the enactment of PURPA, FERC recognized that a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. “First, a utility was not generally required to purchase the electric output, at an appropriate rate. Secondly, some utilities charged discriminatorily high rates of back-up service to cogenerators and small power producers. Thirdly, a cogenerator or small power producer which provided electricity to a utility’s grid ran the risk of being considered an electric utility and thus being subject to State and Federal regulation as an electric utility. Section 201 and 210 of PURPA are designed to remove these obstacles.”).

5 Otter Tail Power Co., 410 U.S. at 367.


7 Id.

8 Id. at 107.
to encourage: “(1) conservation of energy supplied by electric utilities; (2) the optimization of the efficiency of use of facilities and resources by electric utilities; and (3) equitable rates to electric consumers.” Congress wanted to diversify the supply of electric generation resources away from those resources developed, built and owned by vertically-integrated monopoly electric utilities with frequent cost overruns that were passed on to ratepayers, and encourage competition from small power producers and cogenerators. The legislative history of PURPA makes clear that PURPA was intended to increase competition from independent power producers by reducing both fuel price risk and the cost of power. In May 1983, the Supreme Court unanimously upheld PURPA’s provisions and FERC’s determination that the “the nation as a whole would benefit from the decreased reliance on scarce fossil fuels and the more efficient use of energy.”

B. Continuing Need to Protect Competition for Independent Generation

Now that renewable technologies are emerging as cost-competitive alternatives to traditional generation sources, PURPA is more important than ever to ensure that independent generators remain able to compete with monopoly utilities. Even under workable competition, some of PURPA’s goals may be lost if left solely to the marketplace. As they seek to compete independent developers are facing a return of the same tactics by the utilities and the state commissions as they experienced almost forty years ago when the idea of independent

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10 See, e.g., Public Utility Regulatory Policies Act, Joint Explanatory Statement of the Committee of Conference at 98, Report No. 95-1750 (Oct. 10, 1978) (explaining that “the conferees use the phrase ‘not to discriminate against [QFs]’ because they were concerned that the electric utility’s obligations to purchase and sell under this provision might be circumvented by the charging of unjust and non-cost based rates for power solely to discourage cogeneration or small power production.”).
generation was presented as a potential competitive solution to utility dominance. These anticompetitive practices are largely directed at preventing solar generators from obtaining a fixed-price, long-term contract with the incumbent utility, even when such contracts are proposed based on the price a utility would pay for the incremental cost of electric energy or capacity that, but for the purchase from the qualifying facility (QF), such utility would generate itself or purchase from another source (“avoided cost”).

Some now argue that PURPA is an anachronism, that independent power generation has matured to the point that PURPA is now obsolete, that the country’s generation resources are sufficiently diverse, markets for wholesale energy and capacity sufficiently impose price discipline on utilities, and that we can trust the utilities to make the right decisions. These arguments are false. PURPA’s fundamental purpose of ensuring that independent small power producers and cogenerators can compete with incumbent utilities – which are still natural monopolies that do not have an economic incentive to lower costs and benefit consumers – remains as necessary today as it was in 1978.

II. THE U.S. SOLAR INDUSTRY CAN COMPETE AS AN ABUNDANT, RENEWABLE, DOMESTIC ENERGY RESOURCE

The solar industry is one of the most recent success stories of the independent power industry created by PURPA. See Attachment 1. Solar employment expanded last year 17 times faster than the total U.S. economy; the Solar Foundation estimates that there are projected to be more than 280,000 solar industry jobs in the U.S. solar workforce in 2017:

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13 See, e.g., City of Frankfort, 12 FERC ¶ 61,004, 61,010 (1980) (explaining that the Federal Power Act prevents monopoly transmission providers from engaging in anticompetitive conduct and erecting unreasonable barriers to entry); see also Regional Transmission Organizations, Order No. 2000, 89 FERC ¶ 61,285 (1999) (explaining how utilities that control monopoly transmission facilities and also have power marketing interests have poor incentive to compete); Cudahy, supra, at 423-425 (detailing the call to reform arguments employed prior to EPAct 1992, which are a mirror of the claims raised by PURPA opponents at the technical conference).

14 FERC’s implementing regulations at 18 C.F.R. § 292.304(e)(3) set forth the avoided cost concept, as explained in Order No. 69, 45 Fed. Reg. 12214, 12227.
Figure 1


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SEIA strongly believes that Congress’s continued support for and enforcement of PURPA is a necessary component of maintaining the impressive growth of this domestic industry.

Through competition, SEIA’s members are driving down the price of solar power for all customers to levels that can compete favorably with all forms of electric power generation.

SEIA calls attention to the often-repeated assertion that PURPA compels utilities to purchase “high cost” or “overpriced” energy. This is false; by definition, the avoided cost pricing of PURPA contracts can be no higher than the cost the utility would otherwise pay for the next increment of generation that it must procure to satisfy its obligations to serve load. This misconception dates from a prior era, before current technological innovations and efficiencies of scale drove down solar power prices such that the market price for solar is now competitive with other forms of new generation.

15 18 CFR 292.101(b)(6).
16 This falsehood might also have gained traction due to improper conflation between renewable projects seeking (1) PURPA-grounded, avoided cost-based contracts and (2) contracts pursuant to state legislative policy-driven renewable portfolio standards (the latter of which were not tied to avoided cost-based prices). In fact, few – if any – states include an economic value for environmental benefits in the computation of Avoided Cost.
Indeed, the plummeting installed cost of solar systems has created an environment where solar-based energy generation is cost competitive with fossil fuel-based avoided cost calculations.
III. PURPA ENCOURAGES FUEL DIVERSITY AND PROMOTES NATIONAL SECURITY

PURPA was enacted in 1978 in response to the OPEC oil crisis, during which there were dramatic and severe shortages of oil and natural gas that drove electric power prices higher, as these limited fuel sources fueled the majority of the power generation plants in the nation. The dominant goal of PURPA was to reduce reliance on foreign imported fuels by increasing the country’s energy self-sufficiency and fuel diversity.  

Through competition put in place by the Natural Gas Policy Act of 1978, the production of natural gas has largely transitioned into a domestic industry. Through resulting competition and technological advancement, natural gas has become an abundant and inexpensive source of

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domestic fuel and is currently the dominant generation fuel source in the U.S. Yet, the fuel diversity among utilities remains lacking and a system that is overly reliant on one fuel source is not as secure when unexpected constraints, such as a natural disaster, can have devastating impacts on the fuel delivery infrastructure.

PURPA’s goal of promoting fuel diversity is still relevant today. Last year, the North American Electric Reliability Corporation (NERC) released a special assessment of gas-electric interdependencies, which included an investigation of the potential reliability risks to the Nation’s bulk power system due to increased reliance on natural gas. NERC found that areas with increasing penetration of natural gas-fired generation are increasingly vulnerable to gas supply disruptions and threaten bulk power system reliability and recommended that “fuel availability and deliverability should be specifically considered and integrated into resource adequacy and other planning assessments.” These concerns were reinforced by NERC’s long-term reliability assessment released in December 2016. While consumers are currently benefitting from low natural gas prices, such a result could change rapidly if there is an unexpected increase in the price of natural gas due to supply or demand conditions.

In 2016, just under nine percent (9%) of all electricity generated in the U.S. came from fuel-less renewable energy, comprised of six percent (6%) wind power, two percent (2%) biomass power, and about one percent (1%) from each of solar and geothermal power. While

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20 NERC, Short-Term Special Assessment Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation at 12 (May 2016).
21 See NERC, 2016 Long-Term Reliability Assessment (December 2016).
the diversity of the electric generation in the U.S. is greater than it was in 1978, this level of diversity is not a goal achieved.

IV. NEW GENERATION RESOURCES WILL NOT BE CONSTRUCTED IF THE PURPA FOUNDATION IS ERODED

As the Supreme Court has found, the “basic purpose of section 210 of PURPA is to provide a market for the electricity generated by small power producers and cogenerators”23 as “utilities were reluctant to purchase power from, and to sell power to, the nontraditional facilities.”24 These small independent projects bring substantial benefits to the grid and to consumers in all markets, as such projects can often be sited closer to load than traditional central station generators, lowering costs to ratepayers due to the efficient use of utility transmission and distribution assets and reduced construction, operations and maintenance costs. These benefits will be lost if PURPA and its mandates are weakened. The majority of independent power projects, particularly those for fuel-less projects with large capital outlays in construction, rely on third-party financing. Just as utilities can benefit from a twenty year depreciation schedule to finance the construction of their owned power plants, independent producers rely on the capital markets to provide long-term capital to support construction and development of generation projects. The PURPA backstop supports financing for almost every one of these projects, even projects that do not have a sales arrangement under the PURPA construct. In addition, PURPA provides key exemptions from specified regulations that would hinder the ability of a project to obtain financing. PURPA’s mandatory purchase obligation is a vital backstop that financing parties require as a necessary condition of their investments.

24 FERC v. Mississippi, 456 U.S. at 750.
A. Competition in the Generation of Electricity Benefits the Public

At the most basic level, an investor-owned utility is incentivized by the current regulated rate structure to build or buy generation assets so that such costs can be capitalized and a return for the equity shareholders will be generated. The more electric generation plant capitalized or purchased from an unregulated affiliate generates greater profit for the common shareholders of the parent company. Recent utility integrated resource plans demonstrate the continuing preference to meet load growth with utility-owned resources:

- **Idaho Power**’s 2017 IRP evaluates a 20-year planning period from 2017 to 2036, during which they forecast load to grow 0.9% per year for average energy demand and 1.4% per year for peak-hour demand. The IRP states that “additional company-owned resources will be needed to meet these increased demands.”

- **Duke’s** 2016 IRP for South Carolina projects peak-hour demand to grow 1.2% for the summer months and 1.3% for winter months over a 15-year period, with the annual growth rate for energy consumption at 1.1%. The IRP states that Duke must continue to develop utility-owned facilities as well as develop two new natural gas plants and pursue more utility-owned solar.

- **PacifiCorp**, a Berkshire Hathaway subsidiary, projected an increase in system coincident peak load at a compounded average annual growth rate of 0.85% over a 20-year planning period in its 2017 IRP. PacifiCorp largely relies on utility-owned resources for its future generation needs.

In many respects, the situation described in *Otter Tail Power* remains a concern today as small independent developers face challenges in negotiating and contracting with the monopoly utilities. While such a result could be based on small power producers still face a highly...

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21 Idaho Power 2017 Integrated Resource Plan (June 2017)
https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp-IRP.pdf.


23 Id. at 17, 6.

24 Id. at 7-9.


26 Id. (explaining the “preferred portfolio.”)
regulated and monopolistic market throughout most of the Southeast, the Intermountain West, and Pacific Northwest, participation in an ISO/RTO market requires assistance of well-established power marketer (a function many independent generators do not have) and sufficient capital to withstand exposure to the volatile nature of energy pricing.

PURPA’s critics have argued that today’s energy market is more competitive than it was at the time of the law’s passage, obviating the need for PURPA’s purchase requirement. While generation is somewhat more varied than in the past, the majority of utilities rely on projects owned or utility-affiliate sponsored projects – not independent power projects – to support their incremental system needs. What has changed, however, and explains why investor-owned utilities feel threatened is that the share of electricity sales attributed to investor-owned utilities has fallen from 78% of retail sales in 1978 to approximately 52% of retail sales today.

B. Independent Power Producers Face Anticompetitive Challenges

In passing PURPA, Congress established a regulatory structure that brought financial investors, both debt and equity, into the independent power industry. Without access to capital, construction of new generation resources will grind to a halt. As FERC has noted, “in order to be able to evaluate the financial feasibility of a cogeneration or small power production facility, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility.” Unfortunately, some utilities and state commissions are eroding these foundations in order to stifle PURPA projects.

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At the most basic level, third-party financing requires that an independent developer enter into a sales arrangement from the output of its plant that includes (1) a set price for the sale of the product (energy, capacity, and other services) and (2) a financeable term, similar to a utility depreciation or amortization schedule. In attempting to obtain these two basic elements, independent solar producers across the country have experienced anticompetitive challenges from utility contracting practices, with multiple challenges arising with vertically-integrated utilities operating in multiple states outside of an ISO/RTO market. These tactics, while varied, tend to focus on the following issues:

- **Abuse of the Competitive Solicitation:** Some utilities refuse to negotiate with independent power producers and instead mandate that the competitors participate in a future competitive solicitation.\(^{35}\) Such competitive solicitations may only be available once in a multi-year period or may be drafted to disadvantage independent power producers.

- **Unfair Contracting Practices:** FERC's regulations provide for sales from independent power producers pursuant to contracts legally enforceable obligations, but utilities who refuse to come to reasonable terms in contracts (i.e., require provisions that hinder third-party financing) will not acknowledge a legally-enforceable obligation without actual, or at least threatened, litigation.\(^{36}\)

- **Gaming Avoided Cost Calculations:** While not a focus of this panel, we note that some utilities (1) do not provide avoided cost rates that represent the full array of costs avoided by purchasing from the generator and (2) delay negotiations so that developers are pushed into the next avoided cost determination period, often resulting in a lower rate than the generator could have obtained had its right to elect "avoided costs calculated at the time the obligation is incurred" been respected.

- **Discriminatory Interconnection Processes:** Utilities can engage in discriminatory

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\(^{35}\) See, e.g., Ga. Comp. R. & Regs. R 513-3-6-.04(3) (restricting QFs above 30 MW from selling energy except through participation in an RFP). See also Hydrodynamics Inc., et al., 146 FERC ¶ 61,193 (March 20, 2014) (finding a 50 MW installed capacity limitation and a requirement that QFs above 10 MW obtain contracts through competitive solicitation processes inconsistent with PURPA).

\(^{36}\) SEIA members have also encountered instances where they have engaged in contested arbitration to obtain a reasonable, financeable PPA and, a few months later, asked for further draft PPAs based on the finally-agreed form, only to be told that the utility's form had changed and presented with a totally new (and completely unfinanceable) PPA. See generally State of North Carolina Utilities Commission, Docket No. E-22, Sub 530, In the Matter of Fresh Air Energy XIX, LLC, et al. against Virginia Electric & Power Co., db/a Dominion Power North Carolina.
practices because they control the interconnection process. Developers need assurances that the state commissions will not allow a utility to use the interconnection process as a way to prioritize its own generation projects over those proposed by independent developers.

Defending their PURPA rights against these practices is a major challenge for small independent developers that, unlike utilities, do not recover the cost of such legal efforts from the ratepayers. Spending time, money, and other resources contesting unfair utility contracting practices is inefficient for all parties involved and reduces the resources that can be spent on development of needed projects. Many state commissions similarly do not have the resources to timely address such complaints and, in the absence of quick resolution, developers are often forced to abandon otherwise worthwhile projects that face a lengthy delay and elect to pursue lesser projects that can proceed more rapidly. Without PURPA, these independent developers can only expect such practices to intensify and the independent developers will be without any recourse for such unfair practices.

V. INDEPENDENT GENERATION PROJECTS PLACE DOWNWARD COMPETITIVE PRESSURE ON ENERGY PRICES

As explained above, the cost of solar energy production has been coming down rapidly to the point that it is competitive with other forms of electric generation and could allow utilities to displace other higher-priced generation or rely on solar to support new load growth.

37 Two examples in particular: (1) SEIA members have entered into PPAs with PacifiCorp in Oregon (Pacific Power) and, during subsequent interconnection processes, been told that their projects are in a "load pocket" and that the projects would be subject to third party transmission charges in order to effect the sale of power to the utility; notwithstanding the QF is directly interconnected with the utility and in its service territory; and (2) PacifiCorp in Utah, Wyoming and Idaho (Rocky Mountain Power) has a separate interconnection procedure for QF projects, which requires developers to determined very early on in the development cycle if they are going to pursue a QF contract or participate in an RFP in order to seek the PPA required to build a given project.

38 To the extent non-PURPA independent power projects face similar challenges, Congress should consider whether it can expand protections to independent power producers, not repeal the few protections offered by PURPA.
Ultimately, customers are better off if utilities rely more on the low-priced solar power: less fuel cost and price volatility, greater diversity of resources, and lower cost of energy.

A. **Solar Development is not Overwhelming the Grid**

Some critics claim that mandatory purchase obligations under PURPA are creating an untenable amount of unwanted solar generation on electric utility systems. In reality, solar constitutes a relatively small portion of the electric power consumed in the United States. For the twelve-month period May 2017, despite substantial growth in the industry, solar only totaled more than 10% of the total energy generation in one state in the United States: California. In only five other states did the solar account for more than 5% of the total electric power grid. In the ten top states for PURPA solar project development, as shown below in Figure 5, solar constituted only 4.75% of the electricity generated in Utah to negligible amounts in Wyoming and South Carolina.
<table>
<thead>
<tr>
<th>State</th>
<th>Solar Penetration %</th>
<th>State</th>
<th>Solar Penetration %</th>
</tr>
</thead>
<tbody>
<tr>
<td>California</td>
<td>14.02%</td>
<td>Virginia</td>
<td>0.19%</td>
</tr>
<tr>
<td>Nevada</td>
<td>9.06%</td>
<td>Tennessee</td>
<td>0.19%</td>
</tr>
<tr>
<td>Vermont*</td>
<td>8.49%</td>
<td>Pennsylvania</td>
<td>0.17%</td>
</tr>
<tr>
<td>Hawaii</td>
<td>8.18%</td>
<td>Ohio</td>
<td>0.16%</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>6.12%</td>
<td>Washington</td>
<td>0.08%</td>
</tr>
<tr>
<td>Arizona</td>
<td>5.43%</td>
<td>Rhode Island</td>
<td>0.06%</td>
</tr>
<tr>
<td>Utah*</td>
<td>4.75%</td>
<td>Illinois</td>
<td>0.05%</td>
</tr>
<tr>
<td>New Jersey</td>
<td>3.83%</td>
<td>Kentucky</td>
<td>0.05%</td>
</tr>
<tr>
<td>North Carolina*</td>
<td>3.57%</td>
<td>Iowa</td>
<td>0.04%</td>
</tr>
<tr>
<td>New Mexico</td>
<td>3.29%</td>
<td>Montana*</td>
<td>0.04%</td>
</tr>
<tr>
<td>Maryland</td>
<td>2.75%</td>
<td>Arkansas</td>
<td>0.03%</td>
</tr>
<tr>
<td>Colorado*</td>
<td>2.25%</td>
<td>Alabama</td>
<td>0.03%</td>
</tr>
<tr>
<td>Delaware</td>
<td>1.99%</td>
<td>Oklahoma</td>
<td>0.02%</td>
</tr>
<tr>
<td>Idaho*</td>
<td>1.39%</td>
<td>South Carolina*</td>
<td>0.02%</td>
</tr>
<tr>
<td>New York</td>
<td>0.89%</td>
<td>Alaska</td>
<td>0.02%</td>
</tr>
<tr>
<td>Connecticut</td>
<td>0.57%</td>
<td>Kansas</td>
<td>0.01%</td>
</tr>
<tr>
<td>Oregon*</td>
<td>0.47%</td>
<td>West Virginia</td>
<td>0.01%</td>
</tr>
<tr>
<td>Minnesota</td>
<td>0.45%</td>
<td>Wyoming*</td>
<td>0.01%</td>
</tr>
<tr>
<td>New Hampshire</td>
<td>0.39%</td>
<td>Mississippi</td>
<td>0.00%</td>
</tr>
<tr>
<td>Texas</td>
<td>0.39%</td>
<td>South Dakota</td>
<td>0.00%</td>
</tr>
<tr>
<td>Florida</td>
<td>0.36%</td>
<td>North Dakota</td>
<td>0.00%</td>
</tr>
<tr>
<td>Indiana*</td>
<td>0.33%</td>
<td>Georgia</td>
<td>N/A</td>
</tr>
<tr>
<td>Maine</td>
<td>0.29%</td>
<td>Michigan</td>
<td>N/A</td>
</tr>
<tr>
<td>Missouri</td>
<td>0.24%</td>
<td>Nebraska</td>
<td>N/A</td>
</tr>
<tr>
<td>Louisiana</td>
<td>0.20%</td>
<td>Wisconsin</td>
<td>N/A</td>
</tr>
</tbody>
</table>

**"** denotes top 10 states for PURPA solar development
"N/A" denotes insufficient data from solar plant operators and state officials

Source: Energy Information Administration Forms EIA-923, EIA-861, and EIA-861-M

National solar penetration rate during the time period was only 1.59%. SEIA estimates that solar comprised only 0.1% of total electric generation in 2010 and will grow to 3.5% by 2020. Claims
that solar projects are the cause of any current economic challenges at investor-owned utilities are simply not supported by these facts.

B. PURPA Projects Are Only a Small Portion of All Solar Being Procured by Utilities

The statistics provided above include all solar power generated in the United States for the twelve-month period May 2017, ranging from electric energy produced by 300+ MW utility scale solar plants procured by utilities through state-driven environmental procurements (not PURPA), to 300 kW solar projects installed on commercial buildings through a corporate procurement PPA, to 3kW solar systems installed on residential homes. When investigating whether PURPA projects are causing a bow wave of unmanageable, unwanted energy, it is important to note that PURPA projects comprised only about twenty percent of all solar capacity installed during that time. As Figure 6 shows, total solar energy procurement from small power producers pursuant to PURPA’s competition mandate accounted for less than both state-RPS procurement and voluntary procurement in 2016.

Figure 6

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Renewable Portfolio Standard (RPS)</td>
<td>75%</td>
<td>90%</td>
<td>83%</td>
<td>84%</td>
<td>86%</td>
<td>57%</td>
<td>52%</td>
</tr>
<tr>
<td>PURPA</td>
<td>7%</td>
<td>1%</td>
<td>6%</td>
<td>9%</td>
<td>10%</td>
<td>8%</td>
<td>23%</td>
</tr>
<tr>
<td>Voluntary Procurement</td>
<td>18%</td>
<td>9%</td>
<td>5%</td>
<td>8%</td>
<td>5%</td>
<td>14%</td>
<td>23%</td>
</tr>
<tr>
<td>Retail Procurement</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>8%</td>
<td>10%</td>
</tr>
<tr>
<td>Annual U.S. Utility PV Installations (MWdc)</td>
<td>267</td>
<td>784</td>
<td>1,803</td>
<td>2,855</td>
<td>3,922</td>
<td>4,266</td>
<td>10,760</td>
</tr>
</tbody>
</table>

Source: Utility PV Market Tracker, GTM Research
For the sake of informing the Subcommittee as to the total amount of solar power capacity actually being developed as PURPA in the top 10 states for PURPA procurement, SEIA requested, and GTM Research provided, the following summary of the pipeline of solar PURPA projects that are currently operating or are under contract:

Figure 7

<table>
<thead>
<tr>
<th>Rank (Contracted + Operating)</th>
<th>Power Offtake</th>
<th>Contracted Pipeline (MWs)</th>
<th>Projects Operating (MWs)</th>
<th>Contracted + Operating (MWs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>North Carolina</td>
<td>2229</td>
<td>2545</td>
<td>4774</td>
</tr>
<tr>
<td>2</td>
<td>South Carolina</td>
<td>1579</td>
<td>91</td>
<td>1671</td>
</tr>
<tr>
<td>3</td>
<td>Oregon</td>
<td>1365</td>
<td>128</td>
<td>1264</td>
</tr>
<tr>
<td>4</td>
<td>Colorado</td>
<td>1104</td>
<td>0</td>
<td>1104</td>
</tr>
<tr>
<td>5</td>
<td>Utah</td>
<td>50</td>
<td>729</td>
<td>819</td>
</tr>
<tr>
<td>6</td>
<td>Idaho</td>
<td>35</td>
<td>378</td>
<td>414</td>
</tr>
<tr>
<td>7</td>
<td>Montana</td>
<td>314</td>
<td>20</td>
<td>334</td>
</tr>
<tr>
<td>8</td>
<td>Indiana</td>
<td>103</td>
<td>41</td>
<td>144</td>
</tr>
<tr>
<td>9</td>
<td>Wyoming</td>
<td>123</td>
<td>0</td>
<td>123</td>
</tr>
<tr>
<td>10</td>
<td>Vermont</td>
<td>38</td>
<td>3</td>
<td>41</td>
</tr>
</tbody>
</table>

C. A Properly Administered Avoided Cost Calculation Protects Ratepayers and Provides Competitive Discipline

It is important to distinguish, particularly in a market where regulated monopolies can serve as gatekeepers against new market entrants, the impact of a price ceiling and a price floor. Section 210(b) of PURPA and the implementing regulations provide that (1) the purchase price rates must be just and reasonable to the electric consumers of the electric utility and in the public interest; and must not discriminate against cogenerators or small power producers, and (2) the avoided cost is calculated as the incremental costs to the utility of electric energy or capacity, or
both, which, but for the purchase from the independent power producer, the utility would generate itself or purchase from another source.\textsuperscript{39} PURPA does not require and does not permit states to require payments above avoided cost; avoided cost serves as the price floor in a regulated market. In *American Paper Inst. v. American Elec. Power Serv. Corp.*,\textsuperscript{40} the U.S. Supreme Court reviewed FERC’s avoided cost rules in the context of PURPA and Congressional intent, and found that that FERC’s rule was within its authority and found flexibility in the full-avoided cost rule. As the Court noted, waiver of the rule is possible, utilities and independent power producers can negotiate a contract price less than the avoided cost, and a properly computed avoided cost will eventually trend to zero if the utility has met all of its generation needs.\textsuperscript{41}

Subject to their respective state commission approval, utilities themselves perform the calculations and put forth the proposals on avoided costs. Rules in states vary, but generally the utility itself controls the timing and frequency of updates to the avoided cost calculations. If a utility has satisfied its load serving obligation, (1) a waiver can be sought from FERC to eliminate the PURPA purchase obligation under either PURPA Section 210(m) or FERC Regulations 18 C.F.R. § 292.402; (2) the utility can to reduce the avoided cost calculation, thus attracting only new projects that find the new purchase price to be economically efficient; or (3) propose to base the avoided cost on a short-term marginal market (e.g., an ISO/RTO market price), so long as such rate constitutes the true avoided cost. PURPA provides the state regulatory authorities with the jurisdiction to calculate the avoided cost rate, and while there are a variety of rate-making methodologies to complete such a computation, each state commission

\textsuperscript{39} 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.101(b)(6).
\textsuperscript{40} 461 U.S. 402 (1983).
\textsuperscript{41} Id. at 416.
will evaluate whether the utility intends to procure long-run or short-run generation assets, whether the fuel mix is sufficient to meet the state’s needs, and how to price any externalities. If independent power producers, including solar producers, can produce power for a price lower than the avoided cost, consumers benefit. If PURPA or non-PURPA generation sources are less expensive than the avoided cost, then the utility has the means by which to reduce the avoided cost.

Avoided cost not only allows for fair competition by cogeneration and small power producers, but it ultimately benefits consumers by forcing a utility to examine the cheapest forms of electric generation and bring such information into the public process of state commission approval. Customers are the beneficiaries when utilities buy the lowest cost power available, and given the speed of technological development, solar will likely continue to trend to the least expensive source of power available.

VI. CONCLUSION

SEIA appreciates the opportunity to testify on the continued need of PURPA to support independent generation in this country, and its role in providing downward pressure on prices for electricity, ultimately benefiting consumers. The belief that PURPA facilitates purchases of uneconomic generation is false, and the truth of the economics illuminates the continuing tension between PURPA’s independent power model and the cost-of-service based utility business models. I submit that the Subcommittee should focus its review of PURPA on ensuring that competition and innovation can continue and that incumbent utilities are not impeding these breakthroughs with anticompetitive conduct.
Mr. UPTON. We will next hear from Kristine Raper, commissioner for the Idaho Public Utilities Commission.

STATEMENT OF KRISTINE RAPER

Ms. RAPER. Thank you, Chairman Upton.

Distinguished representatives, my name is Kristine Raper. I am a commissioner with the Idaho Public Utilities Commission and I want to thank you for the opportunity to come and participate in this panel today and I look forward to any questions that will be asked after the presentations.

A couple of initial matters that I feel like I need to address, issues that often get conflated within this PURPA discussion but are truly separate and distinct. One is promoting renewable generation and maintaining PURPA are not interchangeable concepts. They are not the same thing. One can exist without the other. And number two, there is a misconception that anyone who seeks changes to PURPA is somehow anti-renewable or opposes a diverse resource portfolio, which is not true. Arguing that renewables are beneficial alternatives to fossil fuels and touting the value of a diverse resource portfolio misses the point. This is about a law which is being manipulated to the detriment of ratepayers and state commissions are struggling to balance the requirements of the act with reliability of the grid and ratepayer indifference, all of which the act requires.

PURPA is not the only way to develop renewables but too much PURPA on the grid does stifle the development of non-PURPA renewables. PURPA developers want to make it look like this is an attack on renewables as a whole. It is not. This is not an apples to apples comparison. The must-purchase obligation makes a QF project very different from other renewable projects. Utilities must absorb energy whether it needs the energy or not.

It is not dispatchable energy that the utility can pull onto the grid when it needs it. QF projects are gaming the parameters of PURPA to maximize profit without any regard to the effect on ratepayers and there are no realistic curtailment allowances that the states or utilities have been able to utilize. These things do not apply to non-PURPA non-QF renewable resources.

Mr. Glass reference to falling costs actually proves my point. If the price of solar has dropped dramatically from 2009 until now, well, we have multiple dozens of contracts where in 2009 they signed onto a 20-year agreement at the prices in 2009. If prices have dramatically reduced since 2009 and we are only eight years out, imagine over the 20-year life of that contract how much those prices inflate each year with the reduction of true costs of solar, and the longer the contract the greater the discrepancy.

If PURPA is to remain, then there need to be some changes. I urge you to consider some of the following solutions. Lowering the 80 megawatt qualifying threshold for small renewable projects—Congress’ Energy Policy Act of 2005 changed a threshold for QFs within organized markets to a 20 megawatt threshold for a presumption that they could be competitive within the market. Well, that is a huge difference. Is 80 megawatts small or is 20 megawatt competitive? So I would urge you to look at that 80 megawatt threshold that exists.
If a QF is within a balancing authority of an energy imbalance market like we have in the West, I also urge you to consider applying that threshold under the Energy Policy Act to QFs within an energy imbalance market. I recognize that there are none in it now and that perhaps is because they wouldn't get the prices that they can otherwise get under QF contracts within the states. But that doesn't mean that they are not meeting the requirements of the Public Utility Regulatory Policies Act. It means that the QF isn't making as much money. But it doesn't mean that QFs aren't competitive within that environment.

Please allow states the discretion to address gaming. It violates the intent of the act and it is harmful to ratepayers. I ask that you modify the must-purchase to consider need and allow for reasonable curtailment. Consider what battery storage is and whether it meets the parameters of the act. And finally, implement a statute of limitations on how long a QF can file a complaint with FERC.

I have 13 seconds and I know this wasn't in my written testimony but there is currently no existing statute of limitations for when a QF can take a state decision and file with FERC for alternative treatment.

I look forward to answering any questions that you have.

[The prepared statement of Ms. Raper follows:]
Powering America: Reevaluating PURPA’s Objectives and its Effects on Today’s Consumers

September 6, 2017

Before the Subcommittee on Energy,
U.S. House of Representatives
Washington, D.C.

Written Testimony of
Kristine Raper, Commissioner
Idaho Public Utilities Commission
SUMMARY OF TESTIMONY

PURPA and FERC regulations create a framework within which small renewable power generation can access the energy market, thereby providing an alternative to fossil fuels. Compensation for the energy sold by QFs to the utilities is supposed to represent the costs that the utility avoids by purchasing the QF power. Rates for purchases from QFs are to be just and reasonable to ratepayers and in the public interest. At the same time, the rates cannot discriminate against QFs.

FERC regulations and early case law provide state regulatory commissions with broad discretion regarding how to implement PURPA. In the last decade, however, FERC has admonished state commissions who attempt to use their discretion to manage the negative consequences of PURPA within their state. PURPA’s “must purchase” requirement leaves states with limited alternatives to balance the requirements of the Act with the responsibility to ensure reliable service and ratepayer indifference as to the energy resource.

Shorter contract lengths are necessary to ensure that the “avoided costs” paid for QF energy can be periodically updated to reflect changes in the dynamic energy market. Gaming and disaggregation should be addressed and disallowed as contrary to the intent of PURPA. If the energy imbalance market (EIM) provides a competitive opportunity within which QFs can participate, then the 20 MW rebuttable presumption that applies in organized markets should apply within the EIM – relieving the utilities of the “must purchase” obligation for projects 20 MW and larger. Curtailment provisions must be made available to the utilities in order to ensure reliability of the grid remains paramount. Serious consideration should be given to whether battery storage qualifies as a renewable resource under the provisions of PURPA. And, finally, the discretion afforded to states to determine how avoided costs are calculated should remain with the states.
Chairman Upton, Ranking Member Rush, and other distinguished Representatives, thank you for the opportunity to submit written testimony in anticipation of our discussion of the Public Utility Regulatory Policies Act of 1978 (PURPA).

A quick overview of the pertinent history and corresponding Federal Energy Regulatory Commission (FERC) rules for implementation of the Act is instructive. PURPA was passed as part of the National Energy Act of 1978. The Act’s goals include the encouragement of electric energy conservation, efficient use of resources by electric utilities, and equitable retail rates for electric consumers, as well as the improvement of electric service reliability. 16 U.S.C. § 2601 (Findings). Congress’s stated intent was to reduce the Nation’s dependence on foreign oil and to encourage the development of renewable power generation as an alternative to using fossil fuels. *FERC v. Mississippi*, 456 U.S. 742, 745-46 (1982).

To encourage the development of renewable power, PURPA requires that electric utilities purchase the power produced by designated qualifying facilities (QFs). “This mandatory purchase requirement is often referred to as the ‘must purchase’ provision of PURPA.” *Id.* 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.303(a). The rate paid by the utility for power produced by the QF is generally referred to as the “avoided cost” rate. The avoided cost rate represents the ‘incremental cost’ to the purchasing utility of power which, but for the purchase of power from the QF, such utility would either generate itself or purchase from another source. See 18 C.F.R. § 292.101(b)(6). This mechanism was intended to “make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly encouraged alternatives.” *Southern Cal. Edison, San Diego Gas & Electric*, 71 FERC ¶ 61,269 at 62,080 (1995).

An abundance of federal court decisions, FERC orders, and state court and commission decisions exist that reiterate the discretion FERC affords the States in implementing PURPA. However, it has been Idaho’s experience that when a state’s discretionary decisions are challenged by the QF at FERC the state is admonished that its actions are not consistent with PURPA and FERC regulations. Consequently, states have been left with very few tools in the toolbox to respond to increasingly sophisticated QFs who are attempting to manipulate PURPA to their financial advantage and to the detriment of ratepayers. In a “must purchase” environment, the state commissions cannot balance the requirements of PURPA with the responsibility to ensure reliable service all while doing no harm to customers if the state commissions are denied the discretion provided by the Act and FERC regulations.

In a dynamic energy market, with advances in energy efficiency and conservation, declining loads, and low market prices, the “must purchase” obligation under PURPA must be revisited. “Must purchase” does not consider the utility’s need for the energy or ability to absorb and balance it. Utilities prepare detailed integrated resource plans and make investments based on perceived need. QFs step in when the market favors them and change many factors that led to the utility’s original conclusions. New QF resources are not contemplated by integrated resource plans because they are not known or measurable by the utility.
Unanticipated small power production facilities are more easily integrated into a utility’s existing transmission and distribution network without negatively impacting reliability.

However, adding generation from multiple 100 MW QFs (disaggregated into 20 MW projects) to a utility whose system peaks in a shoulder month at 1300 MW creates obvious reliability concerns. Moreover, even with the addition of large QF resources, the QF energy rarely displaces the need for a utility-scale project because renewable QF energy is largely intermittent – requiring baseload resources to ensure reliable service. So the question must be asked: what costs are being avoided and how are ratepayers held harmless? Just because the large-scale QF projects have found a way to avail themselves of a law that was clearly intended to benefit small power production facilities does not mean that they should be permitted to continue a practice that violates the spirit and intent of PURPA and causes harm to ratepayers.

Modifications to avoided cost rates can ameliorate some of the negative consequences of a “must purchase” obligation. However, the long-term contracts that QFs claim to need to finance projects will increasingly misrepresent the actual avoided cost to the utility the longer the contract term. Shorter, consecutive contracts, which allow for updates to the avoided cost paid to the QF by the utility, are much more consistent with the intent of PURPA to encourage renewable development without harming ratepayers. Financing should be attainable because, as long as the “must purchase” obligation under the Act exists, the QF can sell its energy to the utility indefinitely. Moreover, neither PURPA nor FERC regulations mandate that the terms of a QF contract allow the project to be financeable. If the market cannot support the cost of the project, then the project should not be built. The backstop provided by PURPA is that the avoided cost rates be set so that ratepayers are indifferent as to the source of their energy and without discriminating against QFs.
Even if avoided cost rates are set in a balanced way, QFs can game the regulations to their advantage – complying with the letter of the law but not the spirit of the Act. As Idaho has experienced first-hand, wind and solar QFs can easily disaggregate in order to maximize profit. A 120 MW wind project exceeds the size to qualify for PURPA – but two 60 MW wind projects (adjacent to one another, sharing interconnection with the utility’s system, with a single source of financing, and shared materials) can self-certify as individual QFs and compel the utility to purchase their power. If a more favorable avoided cost rate is achievable with a smaller QF project, two 60 MW QFs can become six 20 MW QFs. FERC’s one-mile rule has not been an impediment to such behavior by QFs in the West. Because of the nature of particularly wind and solar resources, one mile can be mapped between projects without fatally impairing the project. PURPA only applies to projects that are 80 MW or smaller. A 120 MW wind farm spread out over six miles is certainly in violation of the spirit of an Act whose stated purpose is promoting the development of small renewable generation as an alternative to fossil fuels.

The same gaming could occur in an organized market with respect to the 20 MW rebuttable presumption. A QF that calculates a greater return through the “must purchase” path could disaggregate to less than 20 MW in order to avoid the presumption altogether. State commissions must be provided the discretion to examine the underlying facts and evidence to determine if a QF (or series of QFs) is attempting to exploit loopholes for their financial advantage and to the detriment of ratepayers. Criteria that might be considered in determining whether a series of QF projects are attempting to game the system include:

- Use of the same motive force or fuel source
- Owned or controlled by the same person or entity
- Share a common point of interconnection
- Share common control, communication and/or operation facilities
• Share a common transmission interconnection agreement
• Use of common debt or equity financing
• Subject to a revenue sharing agreement/arrangement
• Obtain local, state or federal land use permits under a single application
• Share engineering or procurement contracts
• Share common land leases
• In close proximity to other similar facilities

Whether a rebuttable presumption regarding access to the energy market is set at 20 MW or 10 MW or 5 MW, the opportunity exists for manipulation. However, setting a lower threshold to apply a rebuttable presumption that QF projects have access to a competitive market would properly recognize larger developers who should be participating in an organized market. Larger generators, no matter the technology, should not be allowed to work around the provisions of PURPA to the detriment of ratepayers.

Consideration should also be given as to whether an energy imbalance market (EIM) provides similar opportunities to QFs as a fully organized regional transmission operator/independent system operator (RTO/ISO) in order to apply a rebuttable presumption regarding access to the market. The EIM allows participation by any merchant generator within the balancing authority. Lower rates available to the QFs through such participation should not be determinative. A stated goal of PURPA is providing market access to energy resources that are alternatives to fossil fuels, despite the utilities’ monopoly. If the EIM provides a competitive market within which a QF can participate, then PURPA’s goals are met and the “must purchase” obligation should cease.

With so much energy entering the electric grid, curtailment provisions are vital to maintaining a reliable system. Rule 304(f) provides that a utility may curtail its purchase of
energy or capacity from a QF when, “due to operational circumstances, purchases from [QFs] will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.” 18 C.F.R. § 292.304(1)(1). On its face, FERC’s rule appears adequate to not only maintain reliability but also ensure that ratepayers are not harmed. However, FERC has since held that a “utility may not curtail unilaterally where the QF electric energy is purchased . . . pursuant to a long-term obligation.” Idaho Wind Partners I, LLC, 140 FERC ¶ 61,219, citing Entergy, 137 FERC ¶ 61,100 at p. 56. The desire for renewable resources should never overshadow or outweigh reliability. Therefore, reasonable allowances for curtailment should be reevaluated.

PURPA and FERC regulations currently allow the states great discretion in how avoided costs are calculated. It is important to continue this practice in order for states to be able to respond to local interests, needs, economies, and circumstances. A one-size-fits-all approach would be disastrous in an energy environment that includes regulation, deregulation, organized markets, bilateral markets, and divergent interests and goals between the states.

Neither PURPA nor FERC’s regulations specifically identify battery storage as a renewable resource eligible for QF status and the benefits provided by the Act. However, FERC issued one decision in 1990 that summarily included battery storage as a renewable resource under PURPA. Luz Development and Finance Corporation, 51 FERC ¶ 61,078 (1990). FERC provides that “. . . in order for a storage facility to be a QF the primary energy source for generation of this energy must be one of those contemplated by the statute for conventional small power production facilities . . .” Id. In other words, energy storage facilities are not renewable resources/small power production facilities per se. FERC went on to clarify that “. . . the primary energy source of the battery system is not the electro-chemical reaction. Rather, it is the electric energy which is utilized to initiate that reaction, for without that energy, the storage
facility could not store or produce the electric energy which is to be delivered at some later time. Since this energy is the primary energy source of the facility, it is necessary to look to the source of this energy as the ultimate primary energy source of the facility.” *Id.* at 61,171. When PURPA was passed in 1978, battery storage on a utility scale was not realistic. This is no longer the case. I urge this Subcommittee and Congress to address whether and to what extent battery storage facilities should be included within the parameters of PURPA.
Mr. UPTON. Thank you.
Stephen Thomas, senior manager energy contracts, Domtar Corporation. Welcome.

STATEMENT OF STEPHEN THOMAS

Mr. THOMAS. Thank you, Chairman Upton, members of the committee.
My name is Steve Thomas. I have worked for Domtar and I am here representing IECA, or I-E-C-A, which is the Industrial Energy Consumers of America. They are a member-led nonpartisan organization that is made up of leading manufacturers. Domtar itself has 23 manufacturing facilities across the U.S. The largest eight or nine of these are our PURPA-qualifying facilities. As such, we believe that PURPA has done its job and in its current form is doing what it is supposed to.

If there are issues that need to be addressed, we filed, I think, 12 recommendations either through new legislation or through guidance from the FERC to state commissions that we think work for us. But one thing that is important is I want to really make a distinction between QFs that are co-generators, like ourselves, and QFs that are small power generators. And co-generators, what we do is we take either heat before it is used in a process or heat that is a by-product of a process and create electricity, and PURPA allows us to do that. And that is really important as manufacturers because it helps reduce our costs, makes us more competitive in global markets.

By doing this, there’s something else that happens. We are more efficient than generation from a utility because we not only use that heat to create electricity, we use that heat to create products. And another important distinction, from co-generating manufacturing facilities is we have a very large permanent job base.

So from an economic development standpoint, once the facility is built, we support a huge number of sustainable jobs going forward. We are not against renewables. We use renewable energy in our own generation. More than 70 percent of the energy we create at our mills is from renewable sources. So the important thing is, again, that distinction between the co-generators and small QFs.
So all of our recommendations that we have offered are based on that clear distinction, a lot of which we have already talked about.

So what are some of those avoided costs is a major issue for us because as co-generators there’s something that doesn’t get realized. As an industry, we still buy 85 percent of our power so we are net consumers, and things that affect the price of electricity, the reliability of electricity hurt us. So our interests align squarely with consumers. We want affordable power that is reliable.

So the avoided cost issue is a really big deal. I think four or five of our points are around avoided costs. We don’t think utilities should be forced to buy capacity when they are flush with capacity and have adequate reserve margins because that hurts us as consumers, whether we are consuming at home or at our place of business.

The 1-mile rule—our footprints are large. Industries like ourselves have a very large footprint a lot of times in rural areas of the country, and that large footprint—the 1-mile rule is small.
We think that should be larger. Again, so we are not forced to pay for capacity that is not needed on the system and the—another one that is critical to us is curtailment. When the grid is surplus generation, we want to be lower in the stacking order than renewables because we are supporting jobs, because we are creating products that are important to the communities that we serve.

So with that, I will look forward to taking any questions you have.

[The prepared statement of Mr. Thomas follows:]
Powering America: Reevaluating PURPA’s Objectives and its Effects on Today’s Consumers

House Subcommittee on Energy

September 6, 2017

Testimony of Stephen R. Thomas, PE
Senior Manager, Energy Contracts
Domtar Corporation

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 utilized 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).

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\(^1\) 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 (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. 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 (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...
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.
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.

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 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’s 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.

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7 PROMOD is a market simulation and production cost modeling software by ABB, a somewhat industry standard for cost modeling at the utility level.
Industrial Energy Consumers of America

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 shining, 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.
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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 292.30S. 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 standby 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.

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, rather 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

CHP Annual Capacity Additions (MW)

Source: DOE/CSP Chp Installation Database (U.S. installations as of December 31, 2014)

FIGURE 3

Industrial CHP Capacity & Generation

Source: EIA
Mr. UPTON. Thank you.

Next, Terry Kouba, Vice President of Iowa Operations of Alliant Energy. Welcome.

STATEMENT OF TERRY KOUBA

Mr. KOUBA. Good morning, Chairman Upton, and members of the subcommittee.

My name is Terry Kouba and I am the Vice President of Iowa Operations for Alliant Energy, which is a Midwest utility serving 1.4 million electric and gas customers throughout 1,300 communities in Iowa and Wisconsin.

First, let me thank the subcommittee for holding this timely oversight hearing. The main focus of my testimony today is to re-evaluate PURPA in light of the law's negative effect on increasing wind energy costs for our customers in Iowa.

Iowa is a national leader in wind energy deployment, deriving 36 percent of the state's electricity from wind, a statistic to which Alliant Energy is a very proud contributor.

Currently, we have more than a thousand megawatts of owned and operated wind plus purchase power agreements from independent power producers and we are in the cusp of executing a plan to add an additional gigawatt of wind energy, a $1.8 billion investment in Iowa to help serve our customers. We are a long way from 1978 when PURPA was enacted and I was a sophomore in college. Forty years ago, the country endured an energy crisis while renewable energy was in its infancy as a cost-effective generation resource. Now, two-thirds of the U.S. is served by wholesale region electricity markets like the Midcontinent Independent System Operator, or MISO, in Iowa.

States across the country in organized and unorganized markets are able to competitively solicit renewable energy. Despite the market-driven deployment of renewable energy in Iowa and across the nation, we are still subject to PURPA's outdated mandatory purchase obligation which has increased electricity cost for our Iowa customers.

Let me explain. Under the law, we are required to purchase power from PURPA-designed qualified facilities. These QF resources are not procured through a competitive bid process despite having access to the MISO market. We cannot negotiate on the price paid for this energy and project locations are chosen for the benefit of the QF investor, not for the benefit of our customers. These QFs that violate the intent of PURPA by structuring their projects into separate LLCs to get around FERC's 20 megawatt size cap in organized markets.

If my company went to the Iowa Utility Board to obtain regulatory approval for one of those projects under a purchase power agreement with an independent power producer like that, I am confident we would be rejected because the cost premiums associated with that power would be too high. The IUB would likely question the need for this expensive renewable power when it is possible to obtain cheaper renewable electricity, especially in Iowa through other means, and the IUB would have an excellent point.

The real losers in this situation are not utilities, rather, customers who are forced to pay higher costs for renewable generation
that can otherwise be procured at competitive prices. And when a quarter of our customers’ income is under $25,000 per year, that is a real concern for our company and our customers.

We believe that these larger QFs should be treated like any other independent power producer and be required to sell energy directly into the organized markets like MISO or negotiate for PPA contracts with a utility like any other independent power producer. Doing so would reduce cost to customers and minimize system impacts that might impair reliability. Congress can take steps to improve implementation, mitigate negative impacts on customers in the grid, and better reflect current market conditions by modernizing this law.

We are encouraged by legislative interest to reform the law in several key areas and we encourage FERC to implement several recommendations found in my written testimony on an administrative basis.

Thank you for the opportunity to appear before the subcommittee today and I look forward to the discussion and any questions you may have.

[The prepared statement of Mr. Kouba follows:]
Testimony of Terry L. Kouba
Vice President - Iowa Operations
Alliant Energy

Before the Subcommittee on Energy
Committee on Energy and Commerce
U.S. House of Representatives

Hearing on “Powering America: Reevaluating PURPA's Objectives and its Effects on Today’s Consumers”

10:00 a.m. 2123 Rayburn House Office Building

September 6, 2017
Executive Summary of
Terry Kouba Written Testimony, Alliant Energy

- Alliant Energy is a Midwest company that provides electric and natural gas service to approximately 1.4 million customers throughout more than 1,300 Iowa and Wisconsin communities.

- Our commitment to deploying cost-effective renewable resources is strong: we currently have more than 1,000 MWs of wind capacity from our existing wind farms purchase power agreements and are in the midst of executing a plan to install up to an additional gigawatt of wind resources, up to a $1.8 billion investment.

- PURPA is an outdated law that can financially harm customers and impact the reliability of the grid.
  - While states across the country – in organized or unorganized markets – are able to competitively solicit renewable energy, utilities are still subject to PURPA’s outdated mandatory purchase obligation. The price paid for this energy is administratively determined, and project locations are chosen for the benefit of the investor of the QF, not the customer, which has led to increased electricity costs for our Iowa customers.
  - QF developers do not approach placement of generation from the holistic perspective that a utility does for system planning purposes. When operational issues on the system associated with the interconnection of these QFs occur, the party responsible for identifying and proving the source of the problem is not the QF developer, but the utility.

- PURPA’s intentions are no longer necessary; instead, QFs are manipulating PURPA’s rules and FERC’s associated regulations to increase customer costs.
  - We are required to purchase power from PURPA-designated QFs, without going through a competitive bid process, despite having access to the MISO market.
  - These QFs violate the intent of PURPA by structuring their projects into separate LLCs to get around FERC’s 20MW size cap in organized markets.
  - The burden imposed by FERC’s one-mile rule makes it difficult to challenge the presumption that individual LLCs should not qualify as “small power producers” under PURPA.
  - Iowa customers are paying a 20% price premium for wind energy, and may pay up to $45 million in increased electric costs due PURPA.

- We believe that large QFs should be treated like any other independent power producer, and be required to sell energy directly into the organized markets, or negotiate PPA contracts with the utility like any other independent power producer. Doing so would reduce costs to customers and minimize system impacts that might impair grid reliability.

- Aside from full repeal of PURPA, Congress can take steps to improve implementation, mitigate negative impacts on customers and the grid, and better reflect current market conditions by modernizing the law.
Introduction

Good morning, Chairman Upton, Ranking Member Rush, and members of the subcommittee.

My name is Terry Kouba and I serve as Vice President of Iowa Operations for Alliant Energy. My company is a Midwest transmission-dependent energy company that provides electricity and natural gas service to 1.4 million customers in Iowa and Wisconsin, and is a Midcontinent Independent System Operator (MISO) participant.

Thank you for the opportunity to testify today, and for holding this timely oversight hearing to examine whether there is still a need for the Public Utility Regulatory Policies Act of 1978 (PURPA) in light of energy market changes over the past 40 years, and, in particular, the law’s unintended consequences in increasing wind energy costs for our Iowa customers. I also look forward to discussing potential congressional reforms to the law and Federal Energy Regulatory Commission (FERC) regulation changes, which, if implemented, would ensure fair, transparent, and cost-effective deployment of renewable energy nationwide.

Iowa is the national leader in wind energy deployment, deriving 36% of the state’s electricity from wind, a statistic to which Alliant Energy is a proud contributor. At Alliant Energy, our commitment to deploying cost-effective renewable resources is strong. Currently, we have more than 1,000 MW of wind capacity from our existing wind farms and purchase power agreements (PPAs). We are also in the midst of executing a plan to install up to an additional gigawatt of wind resources; an investment of more than $1.8 billion by 2020. We feel that clean energy is good for the environment and a good investment for our customers and the more than 1,300
communities we serve in Iowa and Wisconsin. That is why we are working hard to increase the energy we generate from cleaner sources. By 2030, we have a target to reduce our fossil-fueled generation carbon dioxide (CO2) emissions 40% from 2005 levels.

In addition to our $1.8 billion wind energy investments, part of our renewable energy strategy has been, and continues to be, the delivery of wind resources through competitively solicited PPAs with independent power producers on behalf of our customers. Despite the market-driven deployment of renewable energy in Iowa, Alliant Energy is still subject to PURPA’s mandatory purchase obligation, the federal implementation of which has increased electric costs for our Iowa customers. The law, therefore, can result in the deployment of less economic renewable generation in lieu of more cost-effective renewable generation procured in an open market.

A Brief History of PURPA

As a response to the 1970s energy crisis, Congress enacted PURPA to promote energy conservation and foster greater use of domestic energy sources, including renewable energy sources.

The environment in which Congress originally enacted PURPA in 1978 is vastly different from the ways in which energy is produced and used today. Improvements in technology lowered the cost of installing wind and solar energy. Additionally, state-level policies such as Renewable Portfolio Standards, changing customer expectations, and societal demands have all helped create a new energy environment. As a result of these changes, generation from renewable energy resources, such as wind and solar, has increased substantially since PURPA was enacted, and that trend shows no sign of slowing. In 1978, robust energy markets like MISO did not
exist. Now, about half of newly constructed renewable generation capacity in the United States participates in energy markets that provide clear price signals. Additionally, the Energy Information Administration estimates that output from renewable energy will more than triple between 2010 and 2040, while oil-fired generation, the original driver of PURPA, has decreased from 16.5% of all U.S. electric generation in 1978 to just 1% of all current U.S. electric generation resources.

Section 210 of PURPA requires all electric utilities to purchase electricity at state-approved avoided cost rates from qualifying small power producers or qualifying co-generation facilities, referred to as Qualifying Facilities (QFs). QFs in many areas of the country have ample opportunity to bid renewable energy into the energy markets through a state’s competitive bidding process, or a region’s organized markets. However, some QF developers have chosen to rely on PURPA’s mandatory purchase obligation. As a result, electric utilities often purchase renewable power at a premium compared to other available renewable energy resources, such as utility-owned generation or competitively bid PPAs, and our customers bear that premium.

Without updates to the law, Americans may continue to pay more for PURPA power than for similar generated renewable energy available at lower cost in wholesale markets. While the law needs to be changed, it would also be useful for Congress to require FERC to change its regulations that implement PURPA’s requirements. Currently, under FERC’s regulations, utilities’ opportunities to make market-based decisions that ensure renewable energy is deployed in the most cost-effective and transparent manner are limited, as I will detail below.
Gaming of the One-Mile Rule

Under PURPA and FERC regulations, the must-purchase obligation governing organized markets, such as those administered by MISO, applies to QFs that are 20 MW or less. However, QF developers and owners circumvent the 20 MW cap by creating separate corporate entities (such as limited liability companies or LLCs) for each individual wind turbine or small grouping of wind turbines, or disaggregating large projects and siting each turbine at locations more than one mile apart, or utilizing a combination of these two strategies. While these arrangements may conform to the requirements of PURPA and FERC regulations, they violate the intent of PURPA, causing financial harm to customers.

As an example, in Alliant Energy’s Iowa service territory, QF developers and foreign-financed owners are developing large wind farms that exceed the 20 MW threshold. These developers then intentionally disaggregate the large projects into individual or smaller groupings of wind turbines and place them greater than one mile apart from each other. These actions circumvent the 20 MW cap established by FERC as authorized by PURPA – gaming the one-mile rule.

I can cite to three recent examples in which this gaming of the system through disaggregation has occurred:

- First, a 30 MW wind farm in central Iowa was disaggregated into ten separate LLCs, where each LLC owns a single 3 MW wind turbine. All ten LLCs are under common ownership. The wind turbines are sited in small groupings that are greater than one mile apart from each other. Under PURPA’s current regulations, Alliant Energy is required to
purchase energy at avoided cost rates from each of these turbines, which in this example was above market price.

- Second, a 28 MW wind farm in central Iowa was disaggregated into fourteen separate LLCs, where each LLC owns a single 2 MW wind turbine. As with the previous example, the LLCs are under common ownership, and the wind turbines were sited in small groups that were greater than one mile apart from each other. Again, current law requires Alliant Energy to purchase power from these disaggregated units.

- Finally, this same QF developer is seeking to install another 24 MW wind farm, which the developer will disaggregate into eleven individual LLCs to meet the requirements of a QF.

In none of the above examples is Alliant Energy able to challenge the presumption that these QFs are separate because of the safe harbor provided by FERC’s one-mile rule, which is irrebuttable.

These examples cause Alliant Energy’s Iowa customers to pay above market rates for wind energy under PURPA. For example, the 30 MW wind farm referenced above causes customers to pay a 20% price premium over a 10-year contract term. PURPA’s mandatory purchase obligation forces Alliant Energy to purchase 30 MW of wind power at avoided cost rates instead of allowing Alliant Energy to procure that same 30 MW through either a competitive bid process or the MISO markets, both of which provide the opportunity to more accurately determine a market-based price for contracts. Simply put, PURPA creates an incentive for QFs to avoid
competitive resource procurement processes in favor of organizing their business under PURPA, allowing them to ultimately procure above-market rates for renewable energy in a state known for competitively priced wind energy. PURPA was never intended to be a mechanism to guarantee financing for large-scale renewable energy projects.

In one of the examples we cited, the QF developer and owner propose to build a 24 MW wind farm that will be disaggregated in Alliant Energy’s Iowa service territory. The QF developer and owner are challenging Alliant Energy’s avoided cost rate of approximately $25/MWh, instead seeking an inflated rate of $49.50/MWh for a term of 25 years. If they are successful, Alliant Energy’s customers will pay more than $45 million more for energy than if Alliant Energy were to enter into a PPA obtained through a competitive process.

One argument sometimes made by QFs for retaining their privileged position is their claimed lack of access to markets or their claim that participating in organized markets is overly burdensome. In response, Alliant Energy would note that all QFs in the MISO footprint have the option to interconnect directly to the transmission system as an independent power producer and participate in the market. Many QFs could take advantage of the processes available in MISO that allow a small generator of 5 MW or less to use MISO’s Fast Track Process in its Tariff (Attachment X) to interconnect directly to the transmission system. However, QF developers have generally chosen not to connect directly to the transmission system nor directly participate in the electricity markets available to them, but to circumvent the markets by taking advantage of state-level distribution-related interconnection processes made available to end-use customers that require timely interconnections.
While smaller QFs, like combined heat and power facilities, may be correct in stating that participating in markets is burdensome, the QFs with whom Alliant Energy deals are larger, sophisticated enterprises. We believe that these QFs should be treated like any other independent power producer, and be required to sell energy directly into the market or negotiate for PPA contracts with the utility like any other independent power producer.

The situations we describe are not unique to Alliant Energy; other electric companies in non-RTO regions, where the mandatory purchase obligation is capped by statute at 80 MW, also experience PURPA abuse. QF developers that disaggregate larger renewable projects that lose a competitive bid process in order to take advantage of PURPA’s mandatory purchase obligation and force utilities to purchase higher-cost QF energy. The real losers in these situations are not utilities, but customers who are forced to pay higher costs for renewable generation that can otherwise be procured at competitive prices.

**System planning**

PURPA can have some secondary impacts, especially on a system like Alliant Energy’s that consists only of generation and distribution, not transmission assets. Information and models that are common and expected at the transmission level are not as readily available or easily created at the distribution level. For example, Alliant Energy has over 40,000 miles of lines to operate that constantly change resulting in models that quickly become outdated and need to be refreshed. Often, engineering and due diligence is necessary to evaluate the impact of a QF facility. If a QF developer is sophisticated enough to evaluate and understand the impacts of their facility, as they might on the transmission system, then the challenge for utilities is to maintain engineering models that are readily available.
PURPA does not encourage developers to focus on system reliability and long-term grid stability; instead, it generally encourages developers to connect at the site providing the quickest, cheapest access regardless of grid impact. For example, the size and scale of these new PURPA projects often virtually guarantees the backflow of energy from the distribution system to the transmission system. QF developers do not approach placement of generation from the holistic perspective that a utility does for system planning purposes. When subsequent operational issues with the system associated with the interconnection of these QF facilities occur, the party responsible for identifying and proving the source of the problem is not the QF developer, but the utility. Sometimes resolving operational issues can lead to jurisdictional issues as state regulations apply to the distribution system, but PURPA applies to the generator. Thus, interconnecting a QF that was not part of a broader system planning effort can result in increased costs to customers because utilities are responsible for maintaining system reliability – with all of its associated costs – while providing little value to the overall grid.

Policy Recommendations

Aside from full repeal of PURPA, Congress can take steps to improve implementation, mitigate negative impacts on customers and the grid, and better reflect current market conditions by modernizing the law. We are encouraged by legislative interest to reform the law in several key areas, and we encourage FERC to implement several of these recommendations on an administrative basis.

- Congress and FERC should allow utilities to challenge abuses of FERC’s one mile rule as described in the above examples;
• Congress should consider exempting utilities from PURPA’s mandatory purchase requirement if a state regulatory commission finds (1) that the utility’s customers do not need the additional power to meet their customers’ needs or (2) the utility employs integrated resource planning and conducts a competitive resource procurement process that provides an opportunity for QFs to participate;

• Congress and FERC should consider lowering the 20MW threshold to 2MW in organized markets. These markets, like MISO, already provide nondiscriminatory access to transmission and interconnection services to two-thirds of all Americans today where they did not exist 40 years ago;

• Congress and FERC should lower the regulatory burden associated with challenging entities’ ability to disaggregate larger QF projects into smaller project in order to meet PURPA’s size thresholds.

These policy recommendations, if adopted, will benefit all stakeholders in the marketplace by providing greater transparency and logical resource integration, while preventing PURPA abuses that lead to higher energy costs to our customers and all Americans subject to uneconomic QF power. If Congress and FERC take meaningful steps to reform PURPA, we can take advantage of deploying cost-effective renewable energy resources nationwide, while encouraging market competition to better ensure cost fairness for the American people.
Alliant Energy is committed to providing cost-effective renewable energy to our customers as part of a diverse energy mix. We embrace the integration of renewable energy resources, and see the value of those resources for our customers when procured in a competitive manner.

Thank you again for the opportunity to appear before the Subcommittee today, and I look forward to the discussion and any questions you may have.
Mr. UPTON. Thank you.
Mr. Baas, good to see you. Director of the Public Works for Kent County, Michigan.

STATEMENT OF DARWIN BAAS

Mr. BAAS. Good morning.
Mr. UPTON. Sorry about the color change, but welcome.
Mr. BAAS. Go blue.
Mr. UPTON. Go blue is right.
Mr. BAAS. Thank you, Chairman Upton, for providing an opportunity for me to testify this morning. I am the director of the Kent County Department of Public Works in Michigan. I want to discuss this morning how PURPA relates to our waste energy facility.

I would also like to express support for the mandatory purchase obligation under PURPA and encourage Congress to consider modifications that could enhance PURPA in its application and effectiveness for waste energy qualified facilities. PURPA has been a critical part of Kent County's waste energy facility for the last 27 years. Kent County DPW allocates funds for municipal infrastructure for five public services. The waste energy facility is critical in that mission. We provide a sustainable and integrated solid waste management system. We provide base load renewable electricity. We offer grid support and reduce the need for long-term or long distance transmission.

Energy from 76 waste energy facilities nationwide account for more than 2,500 megawatts of renewable energy, 14 billion kilowatts of electrical generation, and avoids 13 million tons of greenhouse gas generation. Our facility in Kent County provides an alternative to landfilling that many local residents, businesses, and industry desire. Facilities like ours are a municipal infrastructure and we must remain competitive in the energy markets. Unfortunately, many have closed and more are at risk of failure, which will strand these local government assets. A significant contributing factor is the outdated and inadequate elements of PURPA policy that fails to value local government and the role that these power plants have.

I have submitted detailed documentation of these challenges so I will just highlight a few. Mandatory purchase contract lengths are unrealistically short and the avoided cost pricing has eroded. It is no longer reflecting the intent of PURPA and the value of our system. Even the facilities between 20 and 80 megawatts are experiencing the same challenges. In Michigan, we are engaged with the Public Service Commission to fight for fair, reasonable, and stable ablated cost.

While the utility we work with has received $759 million in rate increases since 2008 and has another $172 million pending before the PSC, the PSC is attempting to devalue the value of our electrical generation by 24 percent. By doing that, they would take us back to rates that were paid to us 20 years ago. The utility is also attempting to unilaterally cancel our contract with one year's notice, which is very difficult for us.

Local governments also own assets where electricity regulations hinder using our power. For example, we have airports, wastewater treatment plants, and courthouses and many other facilities that
require electricity. But it is very difficult to move that electricity to those facilities. That’s why it is so critical that when we receive realistic pricing that we are in such a better place.

Kent County uses a 10-year planning horizon for capital refurbishment as does any utility that invests in plan reliability. Should we face a situation where we would have a contract cancelled with one year’s notice it could very well lead us to early closure. Without certainty in energy revenue and contract length, we face a lot of uncertainty in how to make investments, how to invest in maintenance and in our operations.

Modifications to PURPA are necessary to ensure long-term viability of this municipal infrastructure. I would welcome opportunity to work with staff on modifications to address these issues.

Again, thank you for the opportunity to appear before you today. I will be pleased to answer any questions you might have.

[The prepared statement of Mr. Baas follows:]
Hearing
Before the Committee on Energy and Commerce
Subcommittee on Energy
United States House of Representatives

September 6, 2017

Powering America: Reevaluating PURPA's Objectives and its Effects on Todays' Consumers.”

Written Testimony of Darwin Baas
Director, Department of Public Works
Kent County, Michigan
Summary of Testimony

Kent County, Michigan owns a waste-to-energy (WTE) facility that produces baseload, GHG mitigating renewable electricity and that is also part of the county's municipal waste processing infrastructure.

WTE facilities are unique renewable energy generators, because many are owned by local governments, and most of the remainder are public private municipal infrastructure partnerships. As such, they face unique and significant obligations unlike other QFs, and face barriers to participating in energy markets.

Kent County not only supports the reaffirmation of current PURPA provisions, but encourages modernization and improvement for WTE QFs.

Nationally, WTE QFs are facing challenges to their long-term viability for a number of reasons, including refusal by utilities to (1) enter into PPAs with new and existing QF facilities, or (2) offer economic avoided cost pricing terms or contract lengths reflecting the grid or environmental attributes of the power, contrary to the purpose of PURPA.

As a result, the viability of existing facilities is at risk. Many QFs are already shuttered, with a resulting loss to the grid of climate friendly, baseload, fuel diverse generation. Without current and enhanced PURPA provisions, that disturbing trend will continue.
Chairman Upton, Ranking Member Rush, and distinguished members of the Subcommittee. Thank you for the opportunity to testify regarding the Public Utility Regulatory Policies Act (PURPA). My name is Dar Baas, and I am the Director of the Kent County Michigan Department of Public Works. Like many other municipal and county governments, Kent County owns, as part of its municipal infrastructure, a Waste-to-Energy (WTE) facility.

WTE facilities are located across the nation--from New York to Florida, to California and Oregon, and I can assure you that our situation is similar to many other municipalities with WTE facilities, who are trying to serve the needs of their citizens to manage large volumes of solid waste and produce reliable, low cost power in their areas, yet have extremely limited financial resources. WTE facilities help us solve multiple problems with a single facility.

I am here today to express support for current rebuttable presumption of a mandatory purchase obligation under PURPA, and to encourage Congress to consider modifications to the law to enhance its application and effectiveness for WTE QFs. The current implementation and reach of PURPA poses challenges for municipalities like Kent County, and threatens the ability to continue to operate such plants.

The 76 WTE plants located across the nation have a baseload renewable electricity capacity of 2547 MW and generate over 14 billion kWh of electricity per year, avoiding nearly 30 million tons of greenhouse gas. Approximately half these facilities are owned by local governments; most of the remainder are public private partnerships between companies and municipalities. These plants have been serving communities for decades, and represent significant, long term public investment. Their shutdown would pose a significant problem for municipalities, ranging
from stranded investment to stranded infrastructure, and additional costs for infrastructure replacement.

Kent County DPW is responsible for spending and obligating public funds on municipal infrastructure to provide public services to our residents. One critical investment is our waste-to-energy facility, which provides two public goods – sustainable waste management and base-load renewable energy. In contrast to many other renewable energy technologies, WTE facilities generate baseload renewable energy typically located next to load centers. As our electrical grid becomes increasingly dependent on intermittent renewable power sources, baseload sources like WTE will help aid in grid stability and resiliency, fuel diversity and reliability, and will reduce long distance transmission burden and associated costs. Additionally, they provide the alternative to landfiling that local residents, business and industries demand.

While these facilities are municipal infrastructure, they must also remain competitive in energy markets. Unfortunately, many have closed and more are at risk of failure, stranding local government investments. A significant contributing factor to that is outdated or inadequate elements of PURPA policy which fail to value the unique local government role these power plants have.

It is critical that Congress retain and reaffirm the rebuttable presumption of utilities’ mandatory purchase obligation from QFs with capacity up to 20 MW, and should consider expanding the rebuttal purchase presumption to WTE QFs up to 80 MW. I would assert that the presumption and obligation is essential for the survival of WTE QFs, as the experience of so many local governments with WTE facilities is that they do not have non-discriminatory access to competitive, organized markets.
WTE facilities are unique because many are owned by local governments, and regardless of ownership, most are public-private municipal infrastructure partnerships. As such, they face unique and significant obligations unlike other QFs, and face barriers to participating in organized and bilateral wholesale electricity markets.

A patchwork of renewable energy laws across the country, compounded by the absence of comprehensive federal renewable energy policy, has had a skewed impact on small QF generators. Varied markets and their instruments, guidelines and laws implementing PURPA have adversely impacted existing and new QFs. WTE's unique partnership with local governments sets it apart from other QFs, as it is affected by both market drivers and public infrastructure obligations. The negative impacts of discriminatory markets on WTE QFs have a direct impact on the ability of local governments to fulfill their duties and obligations.

Nationally, QFs are facing challenges to their long-term viability for a number of reasons, including refusal by utilities to: (1) enter into PPAs with new and existing QF facilities, or (2) offer economic avoided cost pricing terms reflecting the environmental and other attributes of the power, contrary to the purpose of PURPA.

As a result of all of these factors, the viability of existing WTE QF facilities is at risk. Many QFs already are shuttered, with a resulting loss to the grid of climate-friendly baseload generation. Domestic deployment of new baseload WTE QF generation has all but stalled, with only one greenfield WTE development financed and built in the last 20 years, contrary to the purpose of PURPA. These smaller QF operators or local governments also often lack adequate
time or financial resources to (1) fight discriminatory and unfair contracting treatment; and (2) keep up with the rising administrative costs and market hurdles faced by small QFs posed by utilities and market operators, again contrary to PURPA. Increases in administrative requirements and costs associated with interconnection and market participation, while often legitimate and not a market barrier for larger generators and utilities, are often not appropriate for, and have a punitive effect on local governments and their WTE QFs. Existing WTE facilities face an increased gap between energy prices in the market and the costs required to maintain facility economics and to cover burdensome administrative costs. As a result, existing WTE facilities have closed and face risk of closure, and local governments that want to expand or deploy new WTE generation will remain unlikely to do so.

PURPA’s purpose (and the FERC’s corresponding oversight authority) to ensure that small QFs continue to have access and fair compensation are as necessary today as when PURPA was first implemented. The Commission’s policies implementing PURPA should strive to increase the ability of small QFs to provide baseload renewable power to energy markets. Over time, however, the implementation of PURPA has shifted in practice. The objective of PURPA was, and remains today, the development and marketplace deployment of renewable and energy efficient generation technologies that can help serve load and provide other benefits. Congress acknowledged that the development of renewable and energy efficient alternatives is dependent on new generation entrants having access to competitive markets.

The industry has evolved since PURPA’s initial implementation. While some power markets are more competitive, other markets present new barriers to QFs not anticipated at the time of
PURPA implementation. The significant role that local governments play in the development, ownership and operations of renewable energy also was not anticipated. Local governments incorporating WTE into their municipal infrastructure have been providing base-load, clean power for decades. The need has not diminished—it has increased—to incentivize and encourage the development and deployment of environmentally beneficial alternative generation sources, such as WTE, as part of modernizing and upgrading our infrastructure.

Unlike solar, wind or other intermittent energy sources, QFs such as WTE provide power on a consistent and reliable basis to meet “baseload” electricity demand. New challenges such as the California “duck curve” occur due to the inability to meet non-coincident peak demand with intermittent electrical generation. Renewable, but non-intermittent QFs such as WTEs represent an ideal resource to confront these challenges.

The use of non-traditional, locally-sourced feedstock makes WTE a uniquely resilient energy source. Resiliency goes beyond being able to withstand disasters, either natural or manmade, to include the ability to recover quickly and fully. During Superstorm Sandy, for example, three WTE QFs were directly impacted by the storm in the New York/New Jersey region. While other generators were non-operational for a significant time period, one of those WTE QFs continued to export power to the grid uninterrupted, while the remaining two facilities were operational before most of the utility power was restored. Utilities and ISO/RTOs should include small baseload QFs and these positive attributes in their supply plans in order to promote reliable operations overall and to meet their daily demand curve.
Existing PURPA provisions addressing certain QFs fail to meet their intended purpose.

Mandatory purchase contract lengths are unrealistically short, and avoided cost pricing has evolved to where it often no longer reflects the intent of PURPA or the value of attributes which should be prioritized today. Facilities between 20 and 80 mw do experience discriminatory pricing, and the pace of contract renewal combined with artificial barriers have significantly eroded terms and pricing for energy.

More specifically, in Michigan, we are engaged with the PSC to fight for fair, reasonable and stable avoided costs. The utility we deal with has had $759 million in rate increases since 2008, with another proposed increase of $172 million pending before the PCS. They are claiming the 2% of their portfolio generated from QFs is to blame for a 50% residential rate hike. Meanwhile, they are trying to devalue our contract by 24%. This will not allow me the revenue necessary to make routine capital refurbishments, forcing me to seriously consider premature closing.

Artificially low avoided cost calculation for mandatory purchases from small baseload QFs is a national issue. I’ll note both a WTE QF example, and one from outside the WTE context, however there are examples of this throughout the country.

**Florida:** Calculated avoided costs offered to WTE QFs have been below the fuel-only cost of natural gas generation. One example is, a county-owned 77 MW WTE QF facility in Florida that is unable to obtain a nondiscriminatory market for its power, realizing annually millions of dollars of lost energy revenue. Utilities are forgoing contracting with small QFs and instead are building their own renewable generation,
however avoided cost rates do not reflect the price of building such new incremental renewable facilities. \(Florida\ Power\ \&\ Light\ Company,\ Florida\ Public\ Service\ Commission,\ Docket\ Nos.\ 160021-EI,\ 160061-EI,\ 160062-EI,\ Order\ No.\ PSC-16-0472-PCO-EI).\)

**South Dakota:** Prelude, L.L.C., a wind energy developer, filed a complaint on May 2, 2014 alleging that six South Dakota energy co-ops failed and refused to enter into good faith negotiations of respective long term PPAs and offered arbitrarily low avoided cost prices that discouraged development of alternative energy projects. [https://puc.sd.gov/commission/dockets/electric/2014/e114-042/complaint.pdf].

Given the current discrimination against small base load QFs, we have urged FERC to exercise its oversight authority to ensure that avoided costs calculations used throughout the country have a level of consistency and logic given PURPA’s purpose to develop, finance and deploy efficient and clean technologies. The definition of avoided cost must be consistent with this purpose and ensure non-discrimination of small base load WTE QFs.

We urge Congress to clarify PURPA as necessary requiring that “avoided costs” paid to WTE QFs by utilities should incorporate short-run and long-run avoided costs for capacity and energy and include the value of other environmental and operational externalities such as the value of base load renewable energy, diversity of generation mix, proximity to load centers for voltage and VAR support, GHG mitigation, landfill diversion, reliable and resilient power. The unique role they have as critical municipal infrastructure and interplay with local governments should
also be valued. I have attached comments filed with the FERC on behalf of several municipalities and WTE operators that discuss our issues in greater detail. It is my hope that these comments would be useful to the Committee as it deliberates on any PURPA changes and we would be pleased to have the opportunity to participate in such discussions.

Local governments across the country own assets which require electricity, as well as those which produce electricity. However, they face a catch-22: currently, a local government cannot sell to itself or other local entities the WTE renewable power it generates at reasonable prices and, instead, must buy fossil power from the utility grid at a significantly higher price to service those government buildings. Instead, local governments owning or contractually obligated to WTE facilities should be able to sell WTE power to other entities that are contiguous or not contiguous but near to the WTE facility, into a community’s localized autonomous micro-energy transmission system (“microgrid”), and otherwise sell power on a self-service basis directly to other contiguous and non-contiguous local government buildings, and net meter its energy purchased from a utility with the WTE generation it sells to the same utility.

Regulations prevent us from using power we generate for our airports, waste water treatment facilities or court houses. It is therefore critical that WTE QFs up to 80 MW are provided an opportunity to obtain realistic energy pricing and contract terms given the inequities, false market signals and uncertainty in today’s energy markets. It is risky decision-making to invest in maintenance and operations of a facility without knowing whether there will be energy revenue to pay off that investment. Modifications to PURPA are necessary to ensure long term
viability of this infrastructure, and I would welcome the opportunity to work with on the Committee on modifications which could address these issues.

Thank you for the opportunity to appear before you today and I would be pleased to answer any questions that you may have regarding these issues.
Mr. Upton. Well, thank you all, and we are going to now move to questions from members here and we will limit our questions and answers to 5 minutes.

I guess the first question that I have for each of you is we, first of all, appreciate your testimony. Let us talk just a little bit about the statutory and regulatory changes to eliminate the abuse or gaming, as Ms. Raper talked about the 1-mile rule. Would you oppose or support regulatory changes to eliminate such and what might that look like?

Ms. Raper, since you raised it we'll start with you and we'll go in reverse. What should we do about the 1-year rule?

Ms. Raper. Thank you, Chairman.

Mr. Upton. Or the one—I am sorry, the 1-mile rule. Sorry.

Ms. Raper. Sure, Representatives. I think the 1-mile rule alone it is neither here nor there. I think changing the 1-mile rule to a 5-mile rule doesn’t eliminate the problem.

The issues with the 1-mile rule that allow things like wind and solar to overbuild, in my opinion, are that if there’s only 1 mile between projects they have the same interconnection. They are financed by the same thing. Just because they are named alpha bravo charlie delta echo doesn’t make them different projects. And so changing the 1-mile rule only without changing some of the considerations for what truly makes it a separate entity it wouldn’t solve the problem.

There need to be other considerations taken into account because my understanding of the 1-mile rule is that it was intended to make sure that they were separate entities that were doing these builds and it hasn’t worked to that effect.

Mr. Upton. Mr. Thomas.

Mr. Thomas. Thank you. Again, as a manufacturer our footprints are so much larger than that 1-mile. Our concern, again, goes back to reliability.

A lot of times the 1-mile or 3-mile circle, the generation is all the same type. If it is all solar, it is all going to go down when the sun is not shining. If it is all wind, it is going to go down when the wind is not blowing. Or it is going to over produce when the wind is blowing.

So, the generation type comes into effect there, too, and, again, a much larger footprint would not affect manufacturing.

Mr. Upton. Mr. Kouba.

Mr. Kouba. Yes. As I answer that question, let me make it clear that I am here today advocating on behalf of our customer. I, along with my company, am also an advocate for renewable energy.

As I said in my opening statement and my written statement, we have significant renewable energy resources, primarily wind, and we are adding a significant amount more. We are also about to energize the most powerful solar facility in the state of Iowa so we are definitely advocates of renewable energy. With respect to this issue, what we have is sophisticated foreign-owned companies that are planning, proposing, and investing in projects in Iowa that in total exceed the 20 megawatt PURPA cap.

Because they evidently do not want to compete with the generation market in Iowa and MISO, and make no mistake about it, the generation market in Iowa with all our wind is extremely competi-
tive, they disaggregate these facilities into much smaller projects, organize under separate LLCs but ultimately through the same ownership. They then take those smaller facilities that get below the 20 megawatt cap. They spread them apart so they are a mile apart and then they can qualify for PURPA plus we can't challenge that.

So we would propose to eliminate that 1-mile rule so we can challenge these projects that are, clearly, disaggregation that ultimately end up costing our company, in one case, 20 percent more than what we could get with other projects.

Mr. UPTON. I know that I am running out of time. Mr. Baas, it doesn't really impact your folks all that much.

Let me go to Mr. Prager and Mr. Glass and my time will have expired.

Mr. PRAGER. Thank you, Mr. Chairman.

We actually have an actual experience, which I mentioned in my oral testimony, in Texas where we had someone come in and actually game the system in order to use the 1-mile rule to separate a much larger wind project into two different QFs and be able to force the avoided cost pricing.

I think Commissioner Raper really hit it on the head. We need to have a process in place at FERC where FERC looks at the reality of what's happening. It doesn't elevate the form of its 1-mile over the substance of what's actually happening on the ground. If you have one project subject to common control, subject to common interconnection, treated in every respect as one project, even if particular segments of that are a mile apart, they should be treated as one project and therefore not subject to the PURPA requirements.

Mr. UPTON. And Mr. Glass, quickly.

Mr. GLASS. We don't think the 1-mile rule is really an issue for the solar power industry. We use the land more intensively on, like, for instance, a wind farm our average project sizes are such that it just doesn't make sense. We think it works and we have no problem with actually FERC taking a look at the 1-mile rule. However, the one thing that should happen is that the rule needs to be clear and easily determined without an administrative review or result because there's no way to invest capital if the utility or the utility commission is going to gotcha after you've tried to finance a project. It is just not going to happen.

Mr. UPTON. Thank you.

Mr. Peters.

Mr. PETERS. Thank you, Mr. Chairman.

I want to say, first of all, I grew up in a Wolverine household, not a Spartan household. So I am OK with the color.

So one of the themes of this testimony has been that since 1978 the renewables markets have matured in a way that what was originally conceived under PURPA is probably less important now or maybe less needed now.

Mr. Thomas, you raised the issue I wanted to explore about co-generation. Is it your contention that the nature of that particular energy is something that still PURPA needs to rely on? Can you explain a little bit more about how you were distinguishing cogen from other kinds of renewable energy generation?
Mr. THOMAS. Sure, and thank you for the opportunity to, you know, further emphasize. The idea of co-generation is that generation is co-located with load.

So we use what is steam or heat that would otherwise go to waste to create electricity that we use on site. So that part of it is all about the economics of producing our products cheaper.

It has side benefits for the grid. If we were just a load on the grid, the utilities would supply us from a distance. I think 7 percent line losses is not uncommon. So by providing a lot of our energy ourselves we reduce that need.

Mr. PETERS. Right. So you are doing co-generation because it supports your facility’s operations. It lowers your costs. You are not trying to produce energy offsite—you are using it on site?

Mr. THOMAS. Right. We sell——

Mr. PETERS. So you are really not incentivized by PURPA to do co-generation?

Mr. THOMAS. Not at all.

Mr. PETERS. OK.

Mr. THOMAS. We are consumers. We don’t want high prices. We want——

Mr. PETERS. I got it.

Mr. THOMAS [continuing]. Because we don’t sell power back to the grid except for just rare short periods. None of our facilities are net generators month to month. They might, from one hour to another, generate a little bit. But for the most part——

Mr. PETERS. I see. Does anyone have a reason why there’s not a statute of limitations on these challenges? Does anyone understand or think that that is a good policy? Some heartburn about changing that? No?

Mr. Glass, I would just like you to maybe respond to this—with lower renewables costs maybe the role for PURPA has changed.

Can you tell us what kind of easing could happen and what’s the role of PURPA, going forward, and encouraging renewables?

Mr. GLASS. Well, and one of the fine testimonies that was submitted talked about disco balls and shag carpeting, and I commend you for that. I grew up in Spokane, Washington, in the ’70s. It was a great time.

But competition is not out of style and it didn’t go away with the ’70s. I think that if you look at the renewable energy industry, we are up but really natural gas has taken the position of coal and a little bit of nuclear and taken over for petroleum-based generation for that.

But overall, we have not yet achieved the diversity that we need. The more important point is that this idea that somehow or another avoided costs are too high, that is just wrong. And I would like to think that the committee needs to look into that. The subcommittee needs to look into that because the utilities and the utility commissions control avoided cost. There are a number of methodologies by which they do that. We’ve been in a declining cost system and in some cases some utilities and state commissions haven’t got to avoided costs that reflect the true market price. That is not a reason to do away with legislation itself. It is a reason to fix the avoided costs if that is what needs to happen.
Mr. Peters. OK. Would someone like to respond—maybe Ms. Raper or Mr. Kouba—on that issue, the avoided cost issue?

Ms. Raper. I would be happy to. Thank you.

Congressman, regarding the avoided cost issue, could we change our avoided cost in Idaho to be more reflective of a market price? Yes, we could.

Would we damage things like the co-generation that is really not manipulating the system, not attempting to take advantage at the harm of rate payers? They're just using a by-product of what their normal market is.

We would rather be able to have an avoided cost that truly supports what PURPA intended it to be—to be able to bring on those small power producers—renewable power producers and if we reduced it to a market price then we would see probably complete elimination of any of those PURPA projects. Maybe that is the answer.

Mr. Peters. Mr. Kouba.

Mr. Kouba. I will make one quick comment. We did recently change our avoided costs and one of those foreign developers working on a new project then complained that it was too low and is in with the Iowa Utility Board wanting us to basically double the avoided costs.

So I think there are some things that all of us can do to make the avoided costs more realistic. But we still have to agree that no matter how you offset we have a very volatile market out there that changes often. So we are going to have to make sure that we are constantly updating the avoided costs.

Mr. Peters. Thanks for the testimony. My time has expired.

Mr. Walberg [presiding]. I thank the gentleman.

Now I recognize the gentleman from West Virginia, Mr. McKinley.

Mr. McKinley. Thank you, Mr. Chairman.

Mr. Glass, I think we are all familiar with the fact that the electric consumption in this country has been growing about the last 8 years. So there has been this ongoing conflict in the producers of electricity to maintain their market share and I support the idea of the renewables in a big way. I am delighted, but as a result of that, someone's losing.

There are coal producers, coal generating, gas generated, at the expense that seemingly the federal government is trying to support through PURPA and others and tax credits—the use of more solar, wind. We are currently around 15 percent of renewables, I believe, creating power in America. If we continue this, what is the magic number?

And we are subsidizing it at a pretty good clip. I think it is $28 per megawatt hour. Wind has $28 per megawatt hour. I don't know what solar is with that. What is the right level?

Should we continue to be providing subsidies and where did we reach a point that we stopped the subsidies? Is it do we want to get to 50 percent renewables in this country?

Were we trying to get to 100 percent? When do we stop the subsidies?

Mr. Glass. Thank you for the question.
The first thing I would say is that I think the DOE staff report that came out made very clear that it is not renewables causing the issues that you are talking about. Rather, it is the low cost of gas, which is a great domestic source of energy in this country and all of that. So——

Mr. McKinley. No, no, no. I want to stop you on that, please. Five of the last 8 years there has been a rather—I am not arguing over the price of gas. Renewables are continuing to expand, and I applaud that. But it is at a cost. Somebody is losing out market share as a result of that, and it could be gas. It could be coal. It could be nuclear. Somebody is being affected. Where do we go?

If it is 15 percent, should we still be subsidizing companies when they represent 50 percent of the market share?

Mr. Glass. Well, I——

Mr. McKinley. Could you answer that, please? It is a yes or no.

Mr. Glass. Sure. Sure.

I don't have a particular goal. I don't have a federal RPS goal, renewable portfolio standard goal, and I am at least not prepared to speak on behalf of SEIA as to what that might be.

The one thing I would say is that solar right now is less than 1 percent or just about 1 percent of the total, and I think it could grow more, because the reason is I am not so much worried about who is winning and losing market share. I am more interested in reducing the cost of power for consumers and if——

Mr. McKinley. Well, I am interested in keeping jobs for the people that are in the producer——

Mr. Glass. I would love to talk about it. The solar industry——

Mr. McKinley. So, Mr. Thomas, if I could reclaim my time to Mr. Thomas under Domtar, you made a remark in your statement. The renewable energy QFs should not, in your opinion, be allowed to include production tax credits or the value of renewable energy credits in their calculation when they bid into the system. Could you explain that a little bit?

Mr. Thomas. Sure, and thank you for the opportunity.

Basically, what we are saying is, we know renewables are subsidized. We don't object to that. It has done a good job of creating a renewable market.

But when we start bidding into cost-base market systems, those subsidies should not be allowed to be bid in, and that just keeps it on a competitive process because at face value it looks like bidding in, including your subsidies, lowers the price and it does in the immediate.

But in the future, it causes generation assets that are built by utilities to have to be shut down because they can't compete. They're not subsidized.

Once they are shut down for any length of time, then they end up getting mothballed. Their customers are stuck with capital payment on a resource that is not being used.

Mr. McKinley. This may be a fundamental question. My time is almost up. If a utility is required to purchase from a QF facility and yet they have not been successful in bidding into the PJM for that market for that day, are they still required to purchase?

Mr. Thomas. I don't know that I understand the question entirely.
Mr. McKinley. If a utility company is not providing power into the grid but yet are they still required—they are not providing power to the grid that day or that week but yet are they still required to purchase power from a QF?

Mr. Thomas. And PJM is a competitive market. I don’t know the answer—

Mr. McKinley. OK.

Mr. Thomas [continuing]. How a utility would react to that. I know in our situation at PJM where we might sell generation, if we don’t make the bid we don’t generate into the grid.

Mr. McKinley. Yes. I just wondered whether you are required, though, to still purchase power under QF. Thank you. I yield back my time.

Mr. Walberg. Gentleman’s time has expired. I now recognize the gentleman from the state in all of our thoughts and prayers, Mr. Green.

Mr. Green. Thank you, Mr. Chairman, and I would like to thank you and our Ranking Member Rush for having the hearing today. PURPA is an interesting program borne of unique circumstances in the ’70s and I look forward to hearing a variety of perspectives on its modernization from witnesses.

Mr. Prager, in your testimony you talk about PURPA’s must-take provisions and how they affect state resource planning. Can you elaborate on how the right of a qualifying facility under PURPA can interact with local state procurement processes for independent power producers?

Of course, you have to realize I come from Texas and we have ERCOT. So it is different from the rest of the country.

Mr. Prager. We actually operate in the Texas Panhandle, just outside of ERCOT. So our Texas facilities are actually a little bit different than the ERCOT facilities. But the fundamental issue with PURPA and state resource planning is PURPA is a must-take requirement. It is a must contract requirement that happens independent of the state resource planning processes. So you can see in that that what happens is you end up with a independent power producer that comes in as a qualifying facility and it puts the power to the utility outside of the resource planning process. Because for the renewable energy component of PURPA, those facilities are intermittent. It is very difficult for a state which is responsible for maintaining a reliable and a cost-effective power supply to ensure that those facilities are integrated appropriately into the system. That is why we think it is so important that we begin to find a way to integrate the renewable energy requirements that are coming out of states, which are really significant right now and are driving a lot of the renewable energy growth we see on our system with the PURPA must-purchase requirements.

Mr. Green. OK. And your area you serve in Texas I know in west Texas windmills—do you have any of that alternative rather than solar?

Mr. Prager. We do have some solar and we are adding more in Texas. Solar is a tremendous growing resource and Mr. Glass quoted my disco ball quote from my testimony.

I will say that we are excited about the potential for solar, especially in west Texas and in New Mexico. But, again, it is important
to do it the right way, because if you do it the right way you can bring a lot of renewable energy to your customers and do it in a way that is extraordinarily cost effective and reliable. The best way to do that is through the state planning processes.

Mr. GREEN. Well, obviously, from Texas I would love to see us do with solar what we have done with wind power, and for my California friends I am always bragging about how we produce more wind power in Texas than California. So and we like to do solar——

Mr. PETERS. There is a lot of hot air.

[Laughter.]

Mr. GREEN. Well, I offered to send you a whole lot of water last week.

[Laughter.]

Mr. GREEN. Mr. Glass, in your testimony you talk about how SEIA's members are driving down the price of solar to compete favorably with all the other forms of power generation.

Can you elaborate on how current technological innovations and efficiencies of scale have changed PURPA contracts from high-cost contracts of the past to today?

Mr. GLASS. Well, thank you for the question.

I've been developing and financing solar projects for about 12 years now and the price of the installed capacity has come down to about one-sixth of where it actually began when I started practising. And this has been done through technological innovation, massive investment in capacity manufacturing as well as a lot of technological and business model innovation that has driven down these costs to the point where, we have PPAs that are now less than $20 per megawatt hour that are being executed in various places.

We are able and look forward to installing and selling to utilities at those prices.

But the avoided costs we don't control that at all. We are a price taker under the avoided cost methodology that the utility and the utility commission set.

So I would like to encourage to the extent that there are problems with avoided costs that they review those costs and if solar is the best and cheapest alternative, let us set on that and let us get more solar installed because we have 260,000 jobs that have been built over the last 12 years and we'd love to add more.

Mr. GREEN. Well, the original intent of PURPA was to push for alternative sources of power during an energy crisis in the 1970s.

Alternatives today are a booming market, and from your testimony I get the sense that you see the primary purpose of PURPA is increasing competition and putting downward pressure on utility companies to reducing prices for consumers. Is that an accurate characterization?

Mr. GLASS. Yes.

Mr. GREEN. OK. Mr. Chairman, I thank you for holding the hearing, because, again, in the 1970s we also had an embargo on exporting crude oil and we changed that. So maybe we need to look at PURPA and bring it up to date. Thank you.

Mr. WALBERG. I thank the gentleman.

I recognize now the gentleman from Ohio, Mr. Johnson.
Mr. JOHNSON. Thank you, Mr. Chairman. I appreciate it.
And I want to thank all of our panellists for being here today. I appreciate it. Important topic.

Commissioner Raper, in your testimony you state utilities prepare detailed integrated resource plans and make investments based on perceived need. When discussing PURPA, I think it is important to get a better understanding of this process, especially, as you state, when a QF steps in it changes many of the factors that led to the utility’s original conclusions. New QF resources are not contemplated by integrated resource plans because they are not known or measurable by the utility.

So can you describe that process? In other words, how does a utility prepare their integrated resource plans and make investments based on their needs? What is that process?

Ms. RAPER. Thank you, Congressman, and it actually goes a little bit to Congressman Green’s question about the renewable portfolio standards and perceived need.

A utility, every 2 years, does a 20-year plan of what their resource needs might be based on growth and customers and anticipating, based on history, what it is going to look like into the future.

But when a QF comes on, it just puts in a contract, it is a must-purchase. They say, here you go, we want to build. So when rates are favorable to a QF they just come in. There’s no way for the utility during that integrated resource planning process to say OK, we are going to have six new QFs that we are going to bring on. They’re not allowed to limit that. They’re not allowed to say we are going to have five new wind resources and six new solar resources and that is all we are going to take and so we can plan for that, and we have enough caseload in order to cover the intermittency of those resources. They don’t have the ability to plan for that. So what our utilities have been forced to do, and we have watched it with the integrated resource planning process, is it’s one step forward, two steps back.

They make their plan. But then they have to adjust. It’s a good thing they file a 20-year plan every 2 years because they are having to adjust each time they come to anticipate different base load resources to guess at where rates are at right now and what QFs may come online.

Mr. GREEN. I was going to ask you, and maybe you answered this, how long it takes to develop those plans. So if they do it every 2 years for a 20-year out cycle, does it take the full 2 years? Are they working on that for 2 years?

Ms. RAPER. Well, Mr. Kouba may be able to answer that more directly as a utility. But it is my understanding that they are constantly planning. They are constantly modifying and anticipating and doing studies on what they may need.

Mr. GREEN. OK. Continuing on then, can you explain the changes that might need to be made to a utility’s resource plan when integrating a small power production facility?

Ms. RAPER. Well, if it’s a true small power production facility, if it’s a 5-megawatt, a 10-megawatt geothermal plant, then there are incremental modifications that have to be made in order to balance out those resources. But when you get 100 megawatts that is
disaggregated into five 20-megawatt projects, then for our utilities, it's different in the east than it is in the west.

Idaho Power, during a shoulder month when the wind is blowing, their peak load can be as low as 1,100 megawatts. Well, they have more QF resources online than their peak load on those days.

So the ability for them to try to balance that is enormous.

Mr. GREEN. OK. So how do these changes compare when a utility is required to accommodate generation for multiple QFs?

Ms. RAPER. How do the utilities compare?

Mr. GREEN. Yes. Does the process change when a utility is required to accommodate generation for multiple QFs? Does it make it more complicated?

Ms. RAPER. Absolutely. Yes, because you are bringing on a hundred megawatts of resources that are, one, intermittent, that are, two, must take and they are not necessarily being provided at an hour—at a time of year and time of day when the utility needs those resources, and the base load resources of the utilities can only be backed off so far.

Hydro can't be shut off. Coal plants can't be shut off. There's a minimum, you know, must run on those base load facilities.

Mr. GREEN. OK. All right. Well, thank you very much. Mr. Chairman, I yield back.

Mr. WALBERG. I thank the gentleman.

Now I recognize my friend from Illinois, the ranking member, Mr. Rush.

Mr. RUSH. I want to thank you, Mr. Chairman.

I had a question for Mr. Glass and Mr. Baas. The question might have been asked and answered but I really want to know, one of the most contentious issues that critics have cited PURPA's mandatory purchase obligation. Critics argue that the purchase obligation under Section 210 requires them to purchase power that they may not need from small QFs and above market rates. And I'd like to get your response, Mr. Glass and Mr. Baas.

Mr. GLASS. Glass before Baas?

Mr. RUSH. Any way you want to do it.

Mr. GLASS. Thank you for the question.

I have already spoken to the fact that if avoided costs are being created and approved by a regulatory agency, there should not be a situation in which the utility is buying at greater than its incremental cost of buying energy. If PURPA and its implementing regulations are being administered correctly, that is not a situation you'll find it in.

I actually think that—and thank you for the question because I think there are a lot of other issues that we haven't really talked about yet that are being created in the PURPA environment. I think that there are some states that are taking particular steps to eliminate QF projects altogether. They are, for instance, reducing the term to something that is not financeable. They are introducing other requirements such as RFPs and other things that need to be satisfied before a QF can locate.

But the ultimate thing that you have to understand if you are going to have a competitive independent generation capacity in this
country, you need to have the ability to have a long-term stream of revenues to be able to finance these facilities. Utilities have the ability to put costs onto their customers over a 20-, 30-year period. A utility, when it's planning to build generation, does not do it on a 2-year basis; it does it on a longer term.

Well, independent power is looking for the same type of thing. If we are going to put money to work we need to have that long-term stream of revenues and certainty.

Mr. RUSH. Mr. Baas, you want to charge at this?

Mr. BAAS. Yes. Thank you for the opportunity to comment.

In Michigan, the utilities receive full cost recovery and so when the Public Service Commission does rate reviews they are ensuring that the utilities are being paid their full cost of operation. Our facility is a base load facility. It's been providing electricity for 27 years. We certainly are in the planning of the utility and have been there for a long time.

When we look at what the Public Service Commission is doing in terms of determining avoided cost versus what the utilities are being paid, there is a significant difference. And so we believe we are very competitive and we are seeing utilities actually attempt to build new generation capacity at our expense.

When they want to move us to a 1-year notification on a contract it's difficult for us to invest millions of dollars in refurbishment. It's difficult for us to take our 10-year planning horizon to determine what are we going to pay for in the future when it's set up like that.

Mr. RUSH. I want to ask and want to quickly go down the line and simply ask one question. We can start with you, Mr. Baas. Give me a yes or no if Congress should make tweaks to PURPA or leave it as it is. Yes or no.

Mr. BAAS. Yes.

Mr. KOUBA. Yes, we should modify PURPA.

Mr. THOMAS. No, we prefer it in the current form.

Ms. RAPER. Yes, update, Congressman.

Mr. GLASS. No, leave it as is.

Mr. PRAGER. Yes, we believe it should be modified.

Mr. RUSH. Thank you, Mr. Chairman, I yield back.

Mr. WALBERG. I thank the gentleman, and I recognize the gentleman from Missouri, Mr. Long.

Mr. LONG. I might have to watch that on replay. That reminded me of “What's My Line?” when they are yes, no, leave it as it is.

I think I stepped out of the room for just a minute and I believe Mr. Johnson stole my notes so this might sound like familiar territory to what he was asking but I am going to ask these questions of Mr. Prager. Under PURPA's mandatory purchase obligation, a host utility is required to purchase a qualified facility's output even if the utility has no need for additional power.

How does the utility respond to these types of situations?

Mr. PRAGER. Well, I provided the congressman an example of what we are going through in Colorado right now with the particular QF developer that is trying to put to us 1,520 megawatts of power. It presents a very big problem to us. It really does. It means that we can't be certain about what our generation capacity
is going to be. It raises costs for customers. We had some discussion earlier about avoided costs.

Reality with avoided costs is that the avoided costs calculations that are done under PURPA are supposed to make the customer indifferent to whether or not the project is financed or not. That is not the case when a PURPA cost comes in above what would have to be bid into a competitive process. That’s one of the concerns we have about it. It also, when you have a PURPA facility coming on to the system, it locks the ability of other independent power producers to be able to access the marketplace.

I mentioned we have a lot of wind on our system. Sixty-five percent of that is not owned by our company. It’s owned by independent power producers. If a QF comes in and it occupies that field, it will be impossible for those IPPs to come in and take their position. And finally, it also presents for our state and our system some significant challenges in terms of the reliability and protecting the reliability and cost effectiveness of the system.

Intermittent renewables are a technical challenge from an electric system standpoint. You can make it work. We have made it work. We are very optimistic about the future. But you’ve got to do it in the right way.

The problem with PURPA is these projects show up at a time and location of their choosing and it’s very difficult for us to plan around those projects.

Mr. LONG. And what impact does this have on cost to the consumer?

Mr. PRAGER. We believe that PURPA has the potential to raise consumer costs because we have got to accommodate these higher cost resources and we have to do it in a way that will result in additional investment in our system to accommodate the location in which they would be built.

Mr. LONG. And you talked specifically about how it affects the utility’s output?

Mr. PRAGER. Utility output.

Mr. LONG. The utility output, how it affects the QFs?

Mr. PRAGER. We believe it’s very important that the utility have the ability to plan around the system as it’s currently designed and so we think it’s extremely important that the state have the leadership role in terms of setting the strategy that the utility must follow in order to achieve not only a reliable and low cost electric system, which are both critical, but also achieve those public policy goals whether it’s emission reduction or renewable energy.

We found that our states do an extraordinarily good job of that. They do an extraordinarily good job of it and in fact the renewable——

Mr. LONG. So you think they can anticipate and plan for integration?

Mr. PRAGER. It’s hard for them to do it when these projects just show up whenever they want to. It’s very difficult.

Mr. LONG. OK. And so should the state commissions be able to suspend the mandatory purchase requirement if it determines the utility does not need the additional power——

Mr. PRAGER. We believe they should.

Mr. LONG [continuing]. In your opinion?
Mr. PRAGER. We believe they should. Yes, sir.

Mr. LONG. OK. Thank you.

And with that, Mr. Chairman, I yield back.

Mr. WALBERG. I thank the gentleman. And I recognize the gentleman from Iowa, Mr. Loebsack.

Mr. LOEBSACK. Thank you, Mr. Chair. It’s always great to have these hearings so we can hear from a lot of different perspectives.

For me, being from Iowa and particularly proud, obviously, of what we do with wind, Mr. Kouba, you and the other principal utility in the state of Iowa, very, very important when it comes to that.

I do have one quick question. Is there any way we can get to 40 percent of electricity by the end of the year or is that a pipe dream?

Mr. KOUBA. I wouldn’t say it’s a pipe dream and we are working hard to get there.

Mr. LOEBSACK. Yes. It’s going to be hard, because to get there we’re 36 percent now. I do want to say, though, first, I want to mention solar because there is more and more solar in Iowa all the time as well.

A lot of people don’t think of Iowa as having a lot of solar. But it really does, and I really want to thank Alliant for doing what it is doing. We have a lot of RACs that are working on this.

SIPCO is providing solar to five and maybe even more now. I know they are planning to do even more. And we have got a lot of folks, ranging from schools to farms to hog farmers who are installing solar panels.

The ITC, I think, has been very, very good for that. I know there are many concerned about these particular programs and subsidies. But the ITC, I think, has served its purpose and the PTC for wind. There is no question about that. So I am very proud of what I was doing at this point. We have a great story to tell when it comes to wind, and we may be behind Texas when it comes to wind power but we are still ahead of California, nonetheless, and it’s great.

But I am pleased to hear, obviously, the $1 billion commitment to build more wind in Iowa too on the part of Alliant Energy. 4It’s great news, and as for PURPA modernization, I want to ensure, I guess, that wind energy is deployed in the most cost effective manner for my constituents, for all of Iowa, for the entire country, while ensuring that the federal government continues to promote renewable growth energy in my state.

And I think there is a story to tell there. You can elaborate a little bit more. I guess the question that I would have at the outset is has PURPA actually served to drive extensive renewable energy development in the past and where are we to go from there?

You have some policy recommendations. You mentioned the 1-mile rule. But, did it work in the past but now we are just having some difficulty with it at the moment and reforms are necessary? Is that fair to say, Mr. Kouba?

Mr. KOUBA. I would agree it has worked in the past. In some respects, it’s still working. I think for us specifically what we see in Iowa is foreign companies abusing the intent and spirit of PURPA when they disaggregate these projects, move them down to the distribution system which causes all sorts of reliability problems in and of itself.
So it’s those companies we think that are abusing that. Just instead of competing in Iowa in the renewable market, disaggregating the systems, moving down to the distribution system, claiming they are PURPA facilities, spread them 1 mile apart so we can’t even challenge that.

The IUB can’t challenge that. So that is our main concern with what’s going on right now with respect to abuses of PURPA.

Mr. LOEBSACK. Do you have other policy recommendations beyond the 1-mile rule issue?

Mr. KOUBA. We do have policy recommendations. The 1-mile rule is one of them. The other one is to be able to challenge this disaggregation of larger projects.

Also, for the states to be able to say that utilities do not need to buy that capacity and energy when it is not needed and, really, a number of the panelists have talked about how you get that integrated resource planning process in itself and just make that more of a competitive process instead of just those QFs that are disaggregate on those projects and putting it on the utilities.

Mr. LOEBSACK. Right.

Mr. KOUBA. We’re looking for competitive resources for our customers.

Mr. LOEBSACK. Right. And then, ultimately, obviously, it is to make sure that we have competition so that the cost to the consumer is driven down as well.

And so that is really important and I know Mr. McKinley mentioned jobs. In the state of Iowa wind has created thousands of jobs. Solar is creating more jobs every day. Wind certainly has.

In my district alone, I often mention in these hearings that I have a number of wind energy plants in my congressional district alone, two of them in Newton, Iowa, where we once had Maytag, Whirlpool. No longer.

But the wind energy industry has come in and really created a lot of great new jobs, and so I want to continue to do that as best I can.

But thinking also our consumers of energy and making sure that the regulatory framework we have in place, going forward, whatever that may be is going to serve those energy consumers as well.

So with that, I yield back. Thank you, Mr. Chair. I thank the panel.

Mr. WALBERG. I thank the gentleman.

I now recognize the gentleman from Illinois, Mr. Kinzinger.

Mr. KINZINGER. Well, thank you, Mr. Chair, and thank you all for being here. A lot of the questions I wanted to ask have been asked so I will just hit a couple.

Ms. Raper, the driving factor behind PURPA was national security through field diversity after the oil embargo. We have seen great success in energy efficiency in the development of domestic renewables since the ’70s.

Today, however, energy security means more than just security of supply. It’s reliability, particularly during and after extreme weather. It’s grid resiliency. It’s mitigating cyber attacks and some other concerns.
As a state regulator, do you see circumstances where PURPA may impact grid reliability or not allow you the most efficient plan for energy security in your state?

Ms. Raper. Thank you, Congressman. I do see circumstances where PURPA could impact grid reliability because as a must-take resource we are forced to approve contracts and the utility is forced to accept that energy onto their system and they need to find a way to balance that energy.

I don't know about national security risks so much, although I do appreciate you bringing that up because that is becoming a greater and greater concern for the state regulatory commissions.

But it absolutely affects and impacts reliability of the grid when you have more megawatts entering onto distribution and transmission systems than what's being taken off because of flat load and reduced load by energy efficiency measures.

Mr. Kinzinger. Thank you. And to the rest of the panel, does anyone else want to comment on the role of PURPA in light of the much broader definition of energy security?

Mr. Baas. Thank you, Congressman.

Mr. Kinzinger. We'll go over here and then over here. I am sorry. So we'll start with Mr. Glass.

Mr. Glass. Thank you.

Actually, I think it's a great question. It's something that all utility commissioners, and Congress and FERC should all be paying attention to.

I think that we are looking at new types of risks. Not just weather risks, but national security risks of all different types.

I think that there has been a recognition within the utility industry in the last 10 years that with a greater diversity of resources on the system located at different places on the grids, while it might be more complicated, it certainly is a lot more robust in a variety of situations.

And sure, the utility commissions need to know how to use these resources but solar resources in particular and, more broadly, distributed smaller resources throughout the system actually adds a great deal of energy security to the extent that it can be managed better. So I think greater diversity helps with security.

Mr. Baas. My comment was going to be not to forget existing base load renewable energy such as waste energy. The utilities in Michigan are looking to build and construct new capacity when they are really beginning to frown on existing renewable under PURPA. And so I would ask that you consider that.

Mr. Kinzinger. Thank you.

Mr. Prager. In terms of the security of the grid, especially when you think about cyber security, it's never completely clear that you actually are making the grid more secure with more distributed resources.

There is some real value in having greater diversity on the grid to help protect from having one massive failure. The problem is is that with a lot of different facilities on the grid they represent doors into the system where cybersecurity threats can enter in.

We spend a lot of time thinking about this and it is one of the growing concerns as you add more distributed resources to the system and that is true for a lot of these QFs as well.
Mr. KINZINGER. Thank you.

To the panel, you all provided the areas that PURPA could be modernized and improved. With energy technology almost constantly evolving and rapid changes to the kinds of energy security threats we face, what, if anything, should this committee consider in order to make it effective for the next 40 years? And I guess those that participated maybe can answer that question.

Mr. PRAGER. As the energy markets evolve, the best thing to do is let them evolve and to no longer have these kind of forced mandates over the top of the energy markets.

States do a great job in terms of protecting the reliability of the grid. They do a great job in terms of protecting the cost effectiveness of it. There’s lots of market opportunities out there right now. There’s lots of least cost resource planning. The best thing that could happen would be for PURPA to get out of the way and that is really the ultimate advocacy that we are supporting.

Mr. KINZINGER. Thank you.

And Ms. Raper, do you have anything to say on that at all, in terms of what we should consider?

Ms. RAPER. Although I don’t want to disagree with Mr. Prager but I don’t think PURPA is the worst thing on the planet.

I think it’s being abused. And so I think that if we removed the abuse—Idaho’s been implementing PURPA since the early ’80s and there was not a problem until the last decade when the large generators coming in and gaming the system, were manipulating the loopholes in the act, complying with the letter but not the intent of the act.

And I do agree that there is a balance of what Mr. Glass and Mr. Prager said and that is that you put too many renewables and QFs on the system and you actually create a worse environment for them. We believe in distributed generation and the value of distributed generation and keeping the grid consistent and reliable as well.

Mr. KINZINGER. Thank you. Thanks to all of you. I yield back.

Mr. WALBERG. Thank you. Gentleman’s time has expired.

Now I recognize the gentleman from California, Mr. McNerney.

Mr. MCNERNEY. I thank the chairman. I thank the witnesses for coming here today. Interesting testimony and informative.

I got a couple of things out of your testimonies, some ways to improve PURPA. One is to improve the 1-mile rule and to allow states to address gaming. I think that was Ms. Raper and Mr. Thomas. Thank you.

Subsidies are not included in contract negotiations. Mr. Thomas. Large gifts should sell power more competitively—Mr. Kouba—and the need to add QFs to integrated resource planning. Am I mistaken or am I misinterpreting what anyone said on those comments? No?

I think PURPA can be revised to encourage low-emission or zero-emission—carbon emission without increasing cost to consumers. Does anyone disagree with that?

Sure. Go ahead.

Ms. RAPER. If I can just qualify that. I think that that is possible. But I know that Idaho has taken a lot of criticism for their two-year contracts and part of what Mr. Glass is talking about about
a correct avoided cost it may be a correct avoided cost right now based on the factors that you use to predict what that avoided cost ought to be. But the longer the term of the contract because we are in a volatile energy market and it is always volatile, the longer the contract the more disparity there will be between actual avoided cost and what the utility is paying those.

So 20-year contracts, in our opinion, are never going to be representative in the end of what the incremental cost to the utility is.

Mr. McNerney. Well, that may be true. But as a small power producer, it is almost impossible to get financing without some sort of long-term guarantee or contract.

Ms. Raper. May I address that, Congressman?

Mr. McNerney. Yes.

Ms. Raper. It's our opinion that as long as PURPA exists and there is a must-purchase obligation there that the utility has to take that energy, then there is something reliable to go and get financing based on you show them the federal act that says that the utility has to take this energy on an ongoing basis or the modification that can be made.

As we read PURPA now, it says that the cost of that power is either determined at the time that the contract is entered into or upon delivery of the energy.

So to us, if you have a 20-year contract, you determine at the time the contract is entered into what that avoided cost would be. All we tried to do with——

Mr. McNerney. But that is a risk to you and also just a kind of a risk to the power producer because costs may go up, in which case the power producer is stuck at a lower cost.

That is just futures gaming. Whether it's the utility or the producer, you are both taking a risk. Yes?

Mr. Kouba. Yes, could I comment on that?

Mr. McNerney. Sure.

Mr. Kouba. When we go to add resources at our utility and we walk into the Iowa Utility Board to get those approved for 20 years, 25 years, 30 years, we come in there with a whole study for that time period with various scenarios on what happens if gas prices change, what happens if an environment rule changes, carbon taxes change.

So we have the whole gamut of scenarios for 20, 25, 30 years that then they can look at and say yes, this is still a good decision to add this resource over all those scenarios for 20, 25, years.

That's not the case with these folks gaming the system. They come in with no 20-year plan showing that is going to be beneficial to customers.

Mr. McNerney. Right. Well, that is one of the improvements that I think could be made is giving states some ability to fight gaming. Mr. Glass.

Mr. Glass. Congressman, I would say if they are doing that analysis and they know what the long-term costs are, use that to set your avoided costs. It's very simple.

There's no reason why when you are entering into a 20-year PPA as utility that you would use a different set of data than your avoided cost. In order to develop and finance a solo project or any
independent power contract you need a long-term stream of revenues.

You cannot depend upon the market price in any part of this country. Merchant generation in this country is dwindling. There's very little of it actually happening, especially outside organized markets where you can’t effectively hedge against such things.

To allow only 2-year contracts or to require these people to ride the market means the end of PURPA QF contracts and it means the end of independent power.

Mr. McNerney. Right. No, I understand and I agree with that.

How does storage affect PURPA’s viability as a long-term requirement as a regulation?

Mr. Glass. Right now storage is not specifically contemplated in PURPA or in the implementing regulations, to my knowledge. I would say this. The implementing regulations were very sensitive to the difference between energy and capacity and also the other ancillary services that these types of resources can build. I would simply put it this way. Get more sophisticated about the avoided costs. Get sophisticated about the energy, the capacity, and if it makes sense to build in a financing way, to build and install battery we'll build it and there’s greater capabilities that will come with getting compensated with that.

Mr. Walberg. Thank you. The gentleman’s time has expired.

Mr. McNerney. I was about to say that.

Mr. Walberg. We have got votes coming. We are trying to move it on a little bit, and so now I recognize the gentleman from the inspiring state of Texas, Mr. Barton.

Mr. Barton. Thank you, Mr. Chairman. I will be, I think, relatively brief.

I didn't hear the opening statements of the panel. But in answer to Mr. Kinzinger’s questions, Mr. Prager, does your company support repeal of PURPA?

Mr. Prager. We provided several different options in the end of my written testimony. But one of them is yes, we would support the repeal of the Section 210 requirements under PURPA for a forced purchase.

Mr. Barton. I am open to that, and I wasn’t here in '78, believe it or not, but I got here in '84, and we thought about repealing it in the Energy Policy Act of 2005. We did add or change it, which the FERC implemented in Order 688.

Mr. Glass, could you tell me what the average size a solar plant is today?

Mr. Glass. The average size of a PURPA——

Mr. Barton. New construction.

Mr. Glass. Yes. The average size of a PURPA solar project is 8 to 10 megawatts in total. There are some larger and there are, obviously, smaller as well. But for PURPA projects it’s usually in that range.

Mr. Barton. Well, I appreciate that. But if it is not PURPA, what does the economics of solar today indicate the optimum size is? I would think it would be larger than that. But maybe not.

Mr. Glass. Yes. I think for a utility scale solar, I would say the average is now north of 50 megawatts. I think for commercial and
industrial when you are on a flat rooftop there’s a different optimization for, obviously, residential. You’re talking, like——

Mr. BARTON. Right.

Mr. GLASS [continuing]. Five or six kW.

Mr. BARTON. Ms. Raper, you may be the best person on this, since you are a public utilities commissioner. Texas has an open access market system in ERCOT. We deregulated our power generation.

Do you believe, and you may not know this, but nationally is there a problem for these so-called facilities getting access to the grid? There was a concern in the ’70s that since everything was regulated and integrated that there might be.

But in today’s market is that still a problem?

Ms. RAPER. Thank you, Congressman, for the question. I think that there is not a problem for large QFs to have access.

I do believe that there are still co-generation facilities and other small—we have run-of-river hydro that come in under as a QF resource and I believe that those are entitled to those published standard rates that PURPA talks about.

But no, I think that you get to 10 megawatt, 20 megawatt and I think it is insincere for Mr. Glass to represent that the average size is 10 megawatts for a QF.

The average size is 10 megawatts for a QF because the 100 megawatt disaggregated in order to become 10 of those. So yes, I think it’s proven through the Energy Policy Act of 2005 and the modifications that Congress made that there is access in a competitive market for those larger QF facilities.

Mr. BARTON. I haven’t talked to the chairman or the ranking member so I don’t know where the will of this subcommittee is on this issue.

But if you assume that we’re not going to repeal PURPA which, again I would be open to, but you wanted to reform it, is the 80 megawatts standard for a QF and then the 20-watt megawatts standard under FERC’s 688, are those still valid or should those be changed? And I will let anybody take a pop at that.

Mr. KOUBA. We are advocating to lower that 20-megawatt limit down to 2 megawatts.

Mr. BARTON. Two. OK.

Mr. BAAS. And I would disagree. I believe that facilities like ours have a very difficult time moving electricity to the grid competitively. Twenty megawatts at a minimum and for waste energy facilities 20 to 80 would be very helpful.

Mr. PRAGER. And, Congressman, we would support reducing the 80-megawatt limit down and make it consistent with the limit that is associated with competitive markets across the country, especially for states that have competitive least-cost resource planning.

Mr. BARTON. Thank you, Mr. Chairman.

Mr. WALBERG. I thank the gentleman.

I now recognize another proud Texas member, Mr. Flores.

Mr. FLORES. OK. I want to thank the chairman for hosting this informative hearing and also thank you, panel, for your excellent testimony.

Three quick questions, if we can. It seems to me like state policies are driving the growth and renewable generation. They’ve got
renewable portfolio standards—tax credits, competitive procurement requirements, net metering are just a few of those policies.

So two questions out of that statement. The first one is can we even determine if PURPA’s mandatory purchase requirements under Section 210 are still a factor in driving renewable generation as opposed to the state renewable policy?

So Mr. Baas, I will start with you.

Mr. BAAS. The state policies certainly help, but the federal PURPA requirements I think really enhance and provide that umbrella framework for the states to operate.

Mr. FLORES. Which do you think is having a greater impact today?

Mr. BAAS. PURPA.

Mr. FLORES. OK. Mr. Kouba.

Mr. KOUBA. In Iowa, there is no doubt that PURPA facilities aren’t driving renewable growth. It is the utilities driving renewable growth and many other independent power producers driving renewable growth, and we can take advantage of those independent power producers through very competitive RFPs and PPAs and certainly with our own facilities.

We go through RFP processes that make very competitive prices for those projects. So definitely being driven by utilities right now and independent power producers.

Mr. FLORES. Mr. Thomas.

Mr. THOMAS. Thank you. We believe PURPA has had a great impact on us. We would not be nearly as competitive in manufacturing without their ability. I can’t think of an example where PURPA was used with a hammer for us to be able to do this.

Most of the time, we work through with the state or with the utilities and come up with a negotiated contract. But PURPA’s presence is important and it enables that.

Mr. FLORES. OK. Ms. Raper.

Ms. RAPER. Thank you, Congressman.

I think initially PURPA drove some of the renewables that came onto the market. It assisted in people wanting to invest in things like wind and solar and geothermal. But I don’t think that it’s the driving force anymore for getting renewables on the system.

Mr. FLORES. Mr. Glass.

Mr. GLASS. I detailed in my testimony roughly 20 percent of all the solar installation that was installed in the U.S. last year was based upon PURPA-developed contracts.

So it was significant. And I would say for the other 80 percent, PURPA is a very important backstop in case the other end of the offtake contract goes away. Financiers depend upon PURPA as that backstop as Plan B.

Mr. FLORES. Mr. Prager.

Mr. PRAGER. The vast majority, over 95 percent, of the renewable energy on our system, which is, again, the largest renewable wind energy provider in the country, comes as a result of state policies, low costs, and market forces. It’s not because of PURPA.

Mr. FLORES. OK. Thank you.

Did I really get 5 minutes at the beginning?

Mr. WALBERG. You sure did.

Mr. FLORES. Somebody cheated me on the clock.
Anyway, I yield back the balance of my time.
Mr. WALBERG. We took care of the cheat and gave you, in fact, a little bit more in the end. So——
Mr. FLORES. So can I keep going?
Mr. WALBERG. No, no, no. You're——

[Laughter.]

It's always worth a try, though. I appreciate very much the hearing today and I appreciated the fact that four out of six of the panellists also indicated that they were open to tweaking, reforming, altering, or amending the process and over the last few months I've been drafting the PURPA Modernization Act of 2017.

I believe that PURPA is ripe for reform and, if done correctly, it will increase competition, lower utility bills for our constituents, and ultimately promote grid reliability. I am excited to work with this committee to bring about nearly 40 years of law into a change for the 21st century, if we can do that.

I want to thank the witnesses for being here and great to have a Michigander here as well, Mr. Baas.

Mr. Prager, in your testimony, you mentioned that PURPA's mandatory purchase obligation is hindering Xcel's ability to properly undertake critical resource planning.

Can you please elaborate on this and how it's negatively impacting your customers, and additionally, do you think that it would be beneficial if states were given mandatory purchase obligation waiver authority?

Mr. PRAGER. I do think it would be beneficial. States are doing an excellent job right now in making sure that they manage their resource plans, do it cost effectively and achieve these energy policy goals, including some unbelievably aggressive goals for renewable energy development.

My testimony does talk in some detail about some of our experiences, especially the experience that I indicated in Colorado where we are actually being asked to add in a gigawatt and a half of renewable energy that we haven't planned for, that we haven't sited, that we haven't put through the process.

That gigawatt and a half of QF facilities, if they come in, will completely disrupt our resource planning and will raise customer costs and it threatens the reliability of our system.

Mr. WALBERG. OK, Ms. Raper, would you care to add anything?
Ms. RAPER. Amen. I——

Mr. WALBERG. That's fine.
Ms. RAPER. Thank you, Congressman. I agree. Without being able to plan for the resources for QFs when they come on, then it adversely impacts the utility's ability to plan, going forward. And we have seen that in our state with the way the integrated resource plans are submitted every 2 years. There are swings now instead of tweaks to those integrated resource plans and that is a problem. It impacts investment.

Mr. WALBERG. It's a challenge. Yes.

Mr. Prager, you noted that Xcel is the number-one utility provider for wind. You've also touched on the fact that QFs do not face the market competition other IPPs are subject to.

Do you believe that PURPA is counterproductive to renewable electricity competition and is keeping your customers from enjoying
the technological advancements made in renewable generation such as wind?

Mr. PRAGER. We think it’s very important when you bring any resource onto the system including renewable energy, you do it cost effectively. You do it in a way that results in low-cost reliable power for your customers. We have been able to do that outside of the PURPA process. PURPA is not consistent with the way that states are currently doing the resource planning that allows us to bring in that power on a cost-effective and reliable basis. So yes, I would agree with that statement.

Mr. WALBERG. OK. Mr. Kouba, in your testimony there was some mention of reliability impacts to the system due to the integration of these larger QFs on the distribution system. How does a utility plan for or mitigate these issues and, secondarily, who is ultimately responsible for grid reliability issues—the utility or the QF?

Mr. KOUBA. As a matter of fact, we can’t plan for them because these QF facilities now that are being disaggregated and located on our distribution system come in at any given time and we have absolutely no warning. So there is no planning for the future in those cases. It’s basically reacting and doing the best we possibly can to ensure that the rest of our customers on that distribution system aren’t adversely impacted, and in many cases so far they have been adversely impacted.

It’s just if you don’t take these into the resource planning process, you end up having potentially transmission system impacts. We are seeing that now in the distribution system because there’s no adequate planning to add those facilities. They come in at a location. They may not actually be needed there, and they do end up causing problems for our customers—those distribution systems.

Mr. WALBERG. OK. Mr. Kouba, you mentioned that there are opportunities for these QFs to integrate into the transmission system. How do they integrate and are some QF developers bypassing these established processes in MISO?

Mr. KOUBA. How they would integrate in the transmission system is very similar to how we integrate a new resource, whether it is wind or combined cycle natural gas in the transmission system. There is a process in place in MISO to do that. They could walk through that process just like we do and that process helps ensure that as we or QFs or independent power producers are placing generation on the system, we are actually improving the reliability system, not having a detrimental impact on the transmission system.

So they could follow that process just as we do. I think what they are finding is it is a bit of a cumbersome process. It takes some time.

There may be transmission system additions that are needed that are more expensive so they disaggregate—in our case, in Iowa—and put them down in the distribution system where they don’t have to deal with that and don’t have to deal with the cost of transmission system upgrades.

Mr. WALBERG. Well, thank you. My time is expired.

I guess I am not the last one. And now I recognize my friend from New York that somehow got behind me. Mr. Tonko.
Mr. Tonko. Thank you, and if you want to represent me too you can do that.
Mr. Walberg. I’d be delighted to. Couldn’t work well, though.
Mr. Tonko. All right. Thank you. Thank you.
Let me thank the witnesses for joining us this morning because it’s such an important bit of discussion.
Mr. Thomas, I am a big supporter of CHP. With the recent devastation of Hurricane Harvey and other massive storms that are predicted to happen more and more if we don’t address climate change, I am concerned about how we come back from these storms.
I think back to my home State of New York and the damage caused by Superstorm Sandy. During Sandy, we saw, in that whole experience the resiliency of the CHP facilities. In some places, electricity was down for days but CHP kept working.
So has PURPA been successful in bringing more CHP facilities online?
Mr. Thomas. Yes. I think the easy answer is absolutely. The difference with the CHP facility and just the straight manufacturing is you make additional and large capital investment in the generation.
So knowing that you can recoup that over the length of the period—20 years or so—gives us the confidence to install that generation and make that a CHP facility versus just a straight load manufacturing facility.
Mr. Tonko. And can you discuss whether there might be a need to address some definitional or threshold issues with the law? For example, your testimony mentions that many CHP facilities export very little electricity to the grid.
Does it make sense to reclassify the size of a CHP installation based on the amount that is generally exported to the grid rather than what its overall capacity might be ranked?
Mr. Thomas. Yes, and thank you for your question. A lot of times we talk about megawatts when we talk about the PURPA numbers—20 or 80—and for us it’s more about the amount of energy, not the megawatts because our facilities may look like they can net export 20 megawatts, let us say, but we seldom do that because we match the steam load with what we need from manufacturing.
So, we think an energy number is a better way to do that. But leave it in place. Just change it from measuring absolute capacity to measuring the amount of power that is put on the grid.
Mr. Tonko. Thank you.
Mr. Glass, can you explain the relationship between smaller solar projects, those residential or community projects, and those of utilities and the need for standard and expedient interconnection processes?
Mr. Glass. Great question. All three levels—utility scale, commercial and industrial, as well as residential all need very clear straightforward paths to interconnection and where that interconnection creates costs on the interconnecting utility, those costs ought to be worked out and be dealt with so that the cost cause are at pace for those types of things.
SEIA is completely supportive of that type of thing. However, the one thing I would say is that we need to make sure that these smaller types of facilities can efficiently plug in.

It would seem that the panel is most enamoured of the centrally-planned utility model that we had back in the ’60s where there would be no small scruffy co-generator or small energy producer of solar or anything like that that would come interconnected and mess with their plans.

Unfortunately, that very competition I think has been very successful in helping to bring down costs over time and I would encourage—whether it be interconnection I would request that the utility still be required to have that competitive disruptiveness of smaller generation facilities such as solar.

Mr. TONKO. Now, does PURPA play a role in ensuring that there are nondiscriminatory interconnection processes?

Mr. GLASS. Absolutely. It’s the bedrock. If there was no PURPA there wouldn’t have been an EP Act 1992 and an Order 888 and all of the things leading to the New York rev process that is going on right now. We’ve been increasing competition since 1978 and we ought to continue to do so.

Mr. TONKO. And I would ask that, and so is it important to the future of the solar industry that we move forward with these sort of opportunities with interconnection?

Mr. GLASS. Absolutely.

Mr. TONKO. And I understand a number of witnesses represent utilities or facilities in deregulated electric markets.

But you have member companies selling and installing solar projects all across the country. Is PURPA still important to bring competition and generation diversity to areas that have retained the vertically stacked integrated utilities?

Mr. GLASS. Yes. It’s vital in both markets. I would say that a third of the load of the country is still in what we call vertically integrated monopoly utility systems and then the other two-thirds are in the New England—it is ERCOT and California to a lesser extent.

There are different systems that apply and there is solar going in in both. I would say that PURPA is important across all of them for the market access, the transmission, the interconnection that you were just mentioning but also as the financial backstop so that people can get the financial certainty of the stream of revenues over time to be able to finance these projects. So it is vital.

Mr. TONKO. Thank you, and thank you again to all of our witnesses.

Mr. Chair, I yield back.

Mr. WALBERG. Thank you, Mr. Tonko, and again, apologies for looking right past you. Sorry about that.

Making sure I am looking around, I see no other further members wishing to ask questions. I would like to thank all of the witnesses again for being here today.

We appreciate this and I certainly hope that we will continue these discussions. It is an important topic and it is important for energy.

Before we conclude, I’d like to ask for unanimous consent to submit two documents—two letters dated September 5th, the first
from Cypress Creek Renewables, the second from Northwest and Intermountain Power Producers coalition—for the record.

Hearing no objection, they will be submitted for the record.
[The information appears at the conclusion of the hearing.]

Mr. WALBERG. Pursuant to committee rules, I remind members that they have 10 business days to submit additional questions for the record and I ask that the witnesses submit their response within 10 business days upon receipt of the questions.

So without objection, the subcommittee is adjourned.
[Whereupon, at 12:02 p.m., the meeting was adjourned.]
[Material submitted for inclusion in the record follows:]
September 5, 2017

The Honorable Fred Upton
Chairman
Subcommittee on Energy and Power
House Committee on Energy and Commerce
2218 Rayburn House Office Building
Washington, DC 20515

The Honorable Bobby Rush
Ranking Member
Subcommittee on Energy and Power
House Committee on Energy and Commerce
Rayburn House Office Building
Washington, DC 20515

Dear Chairman Upton and Ranking Member Rush:

Thank you very much for convening this week’s hearing on the Public Utilities Regulatory Policies Act of 1978 (PURPA). Cypress Creek Renewables is an independent power producer specializing in the development, construction and operation of utility-scale solar farms. As the nation’s largest developer of Qualifying Facilities (QF’s) under PURPA, we have found the law critical to ensuring competitive access to electricity markets which would otherwise be totally monopolized by the incumbent utility.

At Cypress Creek we have built or are developing QF’s in 10 states across the country. In North Carolina, our first and biggest state, we have over 100 solar farms in operation or construction representing a total investment of over $1 billion dollars, with another $2 billion worth in development. In Oregon we have 17 projects either operational or in construction totaling just shy of $500 million in investment, with another $346 million worth in development. Michigan is the most recent state to expand its PURPA implementation to attract similar investment.

We appreciate the opportunity to provide our views on PURPA implementation as well as bring to the Committee’s attention aspects where implementation can and should be improved. As discussed, in your staff’s memorandum of August 31, 2017, the purpose of PURPA is to counter the monopoly control of electric power generation by diversifying the universe of suppliers and promoting the development of QFs. PURPA does this by requiring utilities to purchase the output of QF’s only if the cost of that power meets the utility’s lowest cost for generating new power on its own, and to do so under long-term contracts. Today PURPA provides consumers with affordable, diverse, alternative sources of electricity while effectively driving economic development in small towns and rural counties.

As the Committee undertakes its review of PURPA, we believe it is important to keep in mind three fundamental principles:

1. By law PURPA ensures the consumer is getting the cheapest possible new power generation. A bedrock principle of PURPA is that a QF cannot receive a contract for its power unless that power can be built cheaper than the utility can build new generation for itself.
2. **PURPA is the only avenue for independent power producers (IPPs) to access the market in many states.** Two-thirds of states still maintain monopoly control of electricity markets. In the relatively few states, such as North Carolina and Oregon, where PURPA has been implemented in compliance with Congressional intent and Federal Energy Regulatory Commission (FERC) directives, PURPA has provided independent power producers access to an otherwise monopolized market. Some states, like Michigan and Washington, are actively working to improve PURPA implementation. However, in the majority of states with regulated monopoly markets, utilities and public service commissions have blatantly failed to comply with PURPA, in some cases even after FERC has ruled against them. There are other states where the public service commissions aren’t even aware of their obligations to implement PURPA.

3. **Independent power producers (IPPs) deliver cheaper new power generation than monopoly utilities, at less risk to consumers.** A monopoly utility has an incentive to build expensive new power generation in order to maximize the profits it is guaranteed under the current rate-basing system. To make matters worse, when things go wrong, ratepayers are often left holding the bag. In contrast, an IPP puts its own capital at risk in the marketplace and shoulders all the risk of construction. If we go one dollar over budget, we eat that dollar. If we go several million dollars over budget, we go bankrupt. We do not get to go several hundred million or even billions over budget, and then pass those losses on to the consumer.

With regard to some of the specific issues of PURPA implementation that could benefit from the Committee’s oversight, we would highlight for your consideration:

1. **First and foremost, PURPA should be enforced.** There are many states in which the requirements of PURPA are being blatantly ignored and violated by utilities and public service commissions. These violations include failure to publish avoided cost rates, using flawed methodologies to calculate avoided costs, refusal to provide long-term financeable contracts, and avoiding or delaying contract negotiations. In some cases, public service commissions have refused to implement or enforce PURPA even when given clear direction by FERC. The QF developer’s ultimate recourse is only in federal court, where the developer must incur significant costs and time delays and faces a severe financial disadvantage relative to the utility.

2. **Where PURPA is enforced, the consumer receives lower cost electricity than in states where it is not enforced.** In Florida, where PURPA implementation has been weak or non-existent, their public service commission recently approved a monopoly utility’s cost recovery on 600 MW of utility-scale solar at $1.75/watt. Virtually every utility-scale solar project in the country at this point is getting built for under $1/watt. The same entity that requested the $1.75/watt cost recovery is routinely building solar projects in other parts of the country for under $1/watt. That same entity is even developing QFs in other service territories in Florida which likely cost less than $1/watt. By comparison, in some states QPs are getting built for under $1/watt and selling electricity at under 4 cents/kwh where the retail rate of power averages over 11 cents/kwh, helping keep downward pressure on consumers’ electricity bills.
3. Utilities manipulate their avoided cost methodologies, applying different standards to their own self-build projects. In states where utilities are forced to present avoided cost data for the public service commission to set rates for QFs, they routinely propose the least favorable methodology in order to drive down the avoided cost rate while utilizing much higher cost numbers for their own self-build projects. The Committee could investigate a number of ways to level the playing field, either standardizing methodologies, giving QFs an avoided cost figure derived from utility Integrated Resource Plans (IRPs), or requiring utilities to generate power at the same price as the avoided cost rate offered to QFs. In a similar vein, utilities should be required to justify their investments based on the same cost-recovery period established for QF power purchase agreements, as was recently ordered by one public service commission.

4. Long term contracts hold down costs for consumers and households. PURPA requires utilities to offer QFs long term contracts, and such contracts provide predictability for QF consumers through either a flat price or a levelized price which remains constant throughout the life of the contract, thereby locking in a steady decrease in the real price of power over time. Particularly at this point in time, historically low natural gas prices have driven avoided cost rates to historic lows, so it is an opportune time to lock in low power prices for years to come, and allows long term PURPA contracts to act as an anchor on electricity prices. Therefore public service commissions should not ask what is the shortest possible contract investors and lenders will finance, but what is the longest possible contract that could lock in low cost power for the consumer.

5. There are other ways to structure electricity market reforms that ensure market access for IPPs and lower cost electricity for consumers. We are aware and acknowledge that like any 40-year old statute, PURPA sometimes creates inefficiencies in its implementation, and at Cypress Creek we are always more than willing to negotiate alternative market structures with utilities, regulators and/or legislators. We just concluded a successful joint effort with Duke Energy on legislation modifying PURPA implementation in North Carolina and creating a competitive procurement program (in which the utility itself can compete), which together with the preexisting and continued PURPA implementation will result in nearly seven gigawatts of renewable energy deployment in that state by 2022.

Should utilities, regulators or legislators seek other ways to reform electricity markets to better ensure efficient allocation of resources, there are numerous market alternatives which can be structured to the benefit of consumers:

a. Market-first: requiring utilities to go to the marketplace first to solicit proposals from IPPs for all new power generation. Giving monopoly utilities control over generation investment decisions, even subject to utility commission oversight, has not proven in the public interest. There is no reason that utilities shouldn’t be required to justify their investment decisions based on pricing comparison to market alternatives. The Oregon Public Utilities
Commission is studying this form of market structure now and if the Committee is interested in reforming electricity markets this concept would be an excellent place to start.

b. Alternative rate design: ensuring investor-owned utilities' shareholder returns are tied to providing consumers the lowest cost electricity, rather than maximizing their capital expenditures.

c. Consumer choice: giving the consumer the choice of whom to buy their electricity from. Texas is the best electricity market in America because it gives consumers a choice in the selection of their electric generation supplier. The experience of markets where the consumer is given a choice at the retail level is that prices for the consumer go down. And just as importantly, consumers are increasingly demanding a choice, both for more options on price and service as well as the source of their electricity. Texas has proven that free markets and low taxes deliver the best product for the consumer.

Thank you again for your consideration of these important topics. We would very much appreciate working with you on any reforms the Committee might consider, and are always willing to work with our utility partners to negotiate fair improvements to current market structures. Please let us know how we can be helpful to you as you consider PURPA’s implementation in today’s power markets.

With kind regards, I am

Sincerely,

Matt McGovern
Chief Executive Officer
Cypress Creek Renewables

5310 S. ALSTON AVE., BLDG. 3, DURHAM, NC 27713
September 5, 2017

Rep. Fred Upton, Chair
 Subcommittee on Energy
 Committee on Energy and Commerce
 2125 Rayburn House Office Building
 Washington, D.C. 20515

Dear Representative Upton:

The Northwest & Intermountain Power Producers Coalition (NIPPC) represents the competitive power industry in Idaho, Oregon and Washington. Our members have invested billions of dollars building thermal and renewable power plants to cost effectively supply utilities with the electricity they need to serve their loads.

While a subset of NIPPC members develop “Qualifying Facilities” under PURPA, the organization as a whole is committed to seeing that the only federal law mandating competition in the power sector is preserved. PURPA offers consumers an alternative to the monopolistic dominance of investor-owned utilities.

We appreciate the committee’s examination of PURPA but we are skeptical of proposals to “reform” the statute. The implementation of PURPA is a state matter and should be left to them to manage under FERC’s highly deferential policy.

When state regulatory commissions responsibly establish avoided cost they create a bulwark that protects captive utility customers from costly and higher risk utility generation. Independent Power Producers (IPPs) invest their own funds developing, permitting, building and operating Qualifying Facilities (QFs). IPPs are rewarded for the risks they assume in insulating ratepayers from utility construction overruns, environmental non-compliance, and laggard capacity factors. While utilities are paid for owning assets, IPPs are paid based on their power plants’ performance.

The value QFs bring in creating and preserving jobs, building tax base in often depressed communities is significant. Generating power from indigenous thermal and renewable resources conforms to PURPA’s original intent of energy independence, which America needs now more than ever.

Please continue to delve deeply into the full PURPA story. In doing so you will find its critics’ representations to be inaccurate and self-serving.

Sincerely,

Robert D. Kahn, Ed.D.
Executive Director
Mr. Frank Prager
Vice President, Policy and Federal Affairs
Xcel Energy
1800 Larimer Street
Denver, CO 80202

Dear Mr. Prager:

Thank you for appearing before the Subcommittee on Energy on Wednesday, September 6, 2017, to testify at the hearing entitled “Powering America: Reevaluating PURPA’s Objectives and its Effects on Today’s Consumers.”

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Monday, November 6, 2017. Your responses should be mailed to Allie Bury, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Allie.Bury@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment
The Honorable Fred Upton

1. State policies are driving growth in renewable generation. Renewable Portfolio Standards (RPS), tax credits, competitive procurement requirements, and net metering programs are just a few of them.
   a. In light of these more recent pro-renewable policies and mandates (since 1978), do we still need PURPA to drive renewable development?

   **Answer:** No. Between the policies identified in this question and the growing competitiveness of renewable energy, PURPA is no longer the primary driver of renewable energy development. As my testimony indicated, Xcel Energy is the nation’s number one utility wind provider and a growing provider of solar energy. We expect to have over 10 GW of wind energy on our system by the early 2020s. Very little of that renewable energy came to us or will come to us because of PURPA.

2. If we set aside PURPA for a moment, do you believe that state policies (including integrated resource planning (IRP), competitive procurement requirements, net metering and renewable portfolio standards) are stable enough to provide a reliable climate for renewable generation?

   **Answer:** Yes. We have built our industry leading renewable energy portfolio principally in reliance on many of those vehicles, along with the competitive price of wind, solar and other renewables. Renewable energy is the fastest growing portion of our energy generation portfolio, and it works because it saves customers money.

3. You say that section 210 is a “creature of another time” and that the energy issues that gave rise to PURPA no longer exist. You also detail a number of QF abuses and the harm to state resource planning from PURPA’s mandatory purchase requirement.
   a. If section 210 is repealed, do you believe that small scale renewable development will be harmed?

   **Answer:** No. If section 210 is repealed, small scale renewable energy development will still occur, driven by state policies, customer interests and competitive pricing. We believe that the small scale renewable energy market will still be robust and provide opportunity for developers, but, without the market distortions of PURPA, it will be more competitive and provide customers with renewable energy at a lower price.

   b. Much of your testimony focused on the trouble caused by renewable or intermittent QFs. Have had similar experiences with other QFs such as industrial co-gen QFs or municipal waste QFs?

   **Answer:** No. Amendments to PURPA in EPAct 2005 effectively resolved abuses of PURPA associated with facilities that were improperly claiming to be cogenerators.
4. As it stands now, under section 292 of FERC’s regulations (18 CFR § 292), the “one-mile rule” is not rebuttable and utilities have little recourse to challenge QF projects that attempt to game this restriction.

   a. Should FERC revise its regulations to allow utilities to demonstrate that a QF developer is attempting to split a single large project into multiple smaller ones to receive the benefits of PURPA?

   **Answer:** Yes. As my testimony indicates, we have experience with QFs that attempted to “game” the one-mile rule to enable a facility with a capacity of greater than 80 MW to qualify as multiple QFs. Utilities should have the opportunity to demonstrate to FERC that a developer’s proposal for multiple QFs is actually a proposal for a single, large facility that could never otherwise qualify under PURPA and its implementing regulations.

5. We’ve heard about situations where a host utility has no need for additional power, but are nonetheless required to purchase the QF output under section 210 of PURPA (i.e. the mandatory purchase obligation).

   a. How does a utility respond to these types of situations?

   **Answer:** As discussed in my testimony, today we are experiencing exactly this situation in Colorado, where a QF is attempting to use PURPA to force us to purchase over 1000 MW of QF power outside of our integrated resource planning process and at prices higher than we are likely to see through this process. Utilities respond to this problem by first working through state PUC processes to oppose these high-priced projects and support the use of existing integrated resource planning processes to procure power. If that effort does not succeed, utilities become involved in litigation over the QF’s right to force the purchase of its output. In the end, however, if neither of these approaches is successful, the utility will be forced to purchase the power and likely pass the cost of the higher priced power on to its customers. The impacts to customers will be exacerbated if the QF displaces existing assets that customers are already obligated to pay for.

   b. Should state commissions be able to suspend the mandatory purchase requirement in situations where it determines that the utility does not need the QF output in order to meet its obligation to serve load?

   **Answer:** Yes. Although we would argue that PURPA today gives states leeway to avoid the mandatory purchase obligation in certain circumstances, federal PURPA policy should be clear that state commissions have the ability to suspend the forced purchase requirement if the QF. This is particularly appropriate if the state resource planning process requires the utility to use competitive bidding or integrated resource planning to acquire its resources.
The Honorable Bobby Rush

1. Does Xcel determine its cost estimates based on long-term avoided cost analysis?

Answer: Xcel Energy is a public utility holding company, and all of our operating companies are vertically integrated utilities subject to traditional utility regulation. Resources, including QF resources, are generally identified and procured in conjunction with resource planning processes and associated competitive procurement processes that identify the most cost-effective resources to serve customer needs. Many QFs seek payment based on the most expensive system resource that would be displaced by QF energy. However, this approach to QF compensation effectively leverages up and works to sustain a utility’s overall system costs rather than pushing those costs lower, as we are able to do through competitive procurement processes. For example, as indicated in my testimony, we are today building wind energy projects that are well below the cost of displaced energy. We call this strategy “Steel for Fuel,” and it is resulting in reduced customer bills.

a. How does Xcel recover these costs from ratepayers, and what is the average timeframe for cost recovery?

Answer: We generally recover these costs through rate adjustments occurring as a result of a general rate case. In some circumstances, state regulatory policy will enable us to recover the costs through a bill “rider” that allows us to recover costs outside of a rate case. The average timeframe for recovery of costs from customers depends on the life of the asset. For example, a natural gas-fired facility typically has a life of 40 years, while a wind farm has a life of 25 years. We recover our costs over the period of time appropriate for the asset.

b. Who assumes the risks associated with project cost overruns related to self-built resources?

Answer: In most circumstances, we present estimates of the potential cost of a self-built project to our state utilities commissions, and, after reviewing those estimates, the commissions require us to bear most of the risks of cost overruns. In some instances we share the risk of overruns and the reward of lower development costs with our customers. In rare circumstances, our customers bear most or all of the risk.

c. Who assumes the risks associated with fuel price volatility related to self-built fossil fuel resources?

Answer: Our customers generally bear this risk. In most cases, we pass fuel costs through to customers through a mechanism called a “fuel clause.” This mechanism applies to both self-built resources and to fossil-based generating plants built by independent power producers under a power purchase agreement with the company.

2. Does Xcel collect a return on equity when entering into PURPA contracts with QFs?

Answer: No.

a. What is the return on equity collected by Xcel on the company’s self-built resources?

Answer: Our return on equity (ROE) for all of our investments—generation, transmission, and distribution—is set during rate cases for each one of our individual operating companies. Our commissions establish these ROEs based on the cost of capital, risk, state policy, and other factors. The currently authorized ROE for our operating companies generally ranges between 9.2% and 10.25%. However, we only earn an ROE on our owned generating resources.
We do not earn on any resource owned by a third-party. For example, in our current wind portfolio, we own roughly less than 13% of the 6,683 MW of wind connected to our system and do not earn a return on the rest of our wind portfolio. We expect that third-party resources will continue to play a significant role in our renewable portfolio even as we add company-owned resources.
Mr. Todd Glass
Counsel
Solar Energy Industry Association
701 Fifth Avenue; Suite 5100
Seattle, WA 98104

Dear Mr. Glass:

Thank you for appearing before the Subcommittee on Energy on Wednesday, September 6, 2017, to testify at the hearing entitled “Powering America: Reevaluating PURPA’s Objectives and its Effects on Today’s Consumers.”

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Monday, November 6, 2017. Your responses should be mailed to Allie Bury, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Allie.Bury@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment
November 6, 2017

Allie Bury
Legislative Clerk
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, D.C. 20515

Re: Responses to Additional Questions for the Record, Powering America: Reevaluating PURPA’s Objectives and its Effects on Today’s Consumers

Dear Ms. Bury:

Please find enclosed my responses to the questions for the record in connection with my testimony at the September 6, 2017 hearing entitled “Powering America: Reevaluating PURPA’s Objectives and its Effects on Today’s Consumers.”

Thank you and please do not hesitate to contact me if any questions arise.

Sincerely,

Todd G. Glass
On behalf of the Solar Energy Industries Association
Responses to the Additional Questions for the Record Posed by the Honorable Fred Upton

1. State policies are driving growth in renewable generation. Renewable Portfolio Standards (RPS), tax credits, competitive procurement requirements, and net metering programs are just a few of them. In light of these more recent pro-renewable policies and mandates (since 1978), do we still need PURPA to drive renewable development?

Yes; PURPA remains the fundamental federal backstop on utilities’ monopsony power across the United States. In the states where consumers are denied access to competitive electric suppliers and vertically-integrated utilities dominate energy markets, PURPA is the only pathway by which independent entities can deliver alternatives to utility-owned generation. In many of these states, independent power producers using PURPA are able to deliver the type of generation that consumers desire at a price that is at or below the regulated-utility’s cost of generation. As Congress recognized in 1978, if left to choose, utilities would prefer to plan, build, and own their generation assets and not purchase from competitive market players. While such behavior is economically rational, those decisions do not support competition and innovation.

It should be noted that a number of states do not allow for competition in the provision of electricity. In addition, more than 20 states (including Idaho) do not have renewable portfolio standards as shown below:
As a matter of practical antidote, often times the states that do not have RPS standards are most hostile to independent power producers exercising their rights under PURPA; affirming the need for federal backstop authority to ensure competition in wholesale generation. As Commissioner Raper from Idaho testified, some state commissioners prefer to not have their utilities buy power on a long-term basis from renewable QFs at all, as these states disagree with the Congressional determinations set forth in PURPA that consumers benefit from such competition.

With respect to your specific inquiries: in most cases, competitive procurement programs serve as the implementation vehicle of legislative directive for renewable procurement or integrated resource planning. In practice, a state commission oversees a utility-run solicitation where the purchasing utility creates the solicitation, sets forth the metrics and criteria by which to evaluate competitive proposals, selects the most suitable project from all proposals received (possibly without non-discrimination guarantees), negotiates the contracts, and ultimately make decisions reflective of both shareholder interests and the program’s goals. While the existence of such programs reflects an improvement from a utility monopoly control, the result is only as fair as the process by which the solicitation was conducted. Too often small developers often are faced with the untenable choice of either abandoning a project so to preserve the equity balance for a future project or using their limited equity to fund extensive litigation or formal arbitration efforts (which may or may not be successful) against the incumbent utilities which have a deep bench of experienced
professionals and the authority to recover all such legal and expert expenses as part of their rate base before state utility commissions.

Net metering, in contrast, involves designing a rate structure to allow a utility’s customers to fund and install on-site generation and then net the generation excess against the customer’s consumption. While net-metering is another policy that has encouraged some type of renewable energy development, it does not relate to the utility’s purchase of renewable generation from independent power producers and has little effect on projects in excess of 1 MW. The methods by which net metered generation is taken into account for purposes of resource planning or procurement varies by state, with some state commissions not requiring the utility to analyze the impacts of distributed energy resources on utility resource plans.

Despite the existence of state programs, PURPA is an essential piece of federal legislation that backstops competition by ensuring that independent generators will continue to enter the market and put downward pressure on energy prices, while simultaneously supporting the continued legitimate objectives of achieving fuel diversity and enhancing national security.

2. If we set aside PURPA for a moment, do you believe that state policies (including integrated resource planning (IRP), competitive procurement requirements, net metering, and renewable portfolio standards) are stable enough to provide a reliable investment climate for renewable generation?

No. While state policies can incentivize procurement of renewable generation regulation of wholesale generation markets have been the exclusive province of the federal government, as codified in 1935 when Congress enacted Part II of the Federal Power Act. Starting in 1978 with PURPA, and following in the 1992 Energy Policy Act as well as the 2005 Energy Policy Act, the federal government has shown a consistent commitment to bringing competition into the wholesale markets for electric generation and ensuring open access to that market. Given the unique and exclusive federal role ensuring access to liquid and competitive wholesale markets, the state policies do not create the investment climate as much as they can impact the functioning of the federally-regulated markets. Without federal backstop authority for ensuring that independent power producers can compete in the market for wholesale generation, utilities could discriminate against low-cost renewable entrants.

Almost every new generation resource that has been constructed by independent developers over the past twenty years has used a project finance model. PURPA provides crucial legal and regulatory support for these development and project financing efforts. Innovative market participants are motivated to take advantage of the opportunities that each state may use, whether through the legislature or the state utility commission, to enter a market and provide services to consumers at the lowest-possible price. Development, however, is only the first stage of the cycle of market entry.

Once an independent market participant has developed a business model to provide the function or service desired, the market participant then turns to the markets in order to access
debt and equity capital to support construction of the necessary project components. Without access to capital, construction of new generation resources will grind to a halt. As FERC has explained, “in order to be able to evaluate the financial feasibility of a cogeneration or small power production facility, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility.”

While state policies can provide opportunities, standing-alone, the existence of state policies does not provide a stable and reliable foundation to support new entry by independent market participants. Stable and consistent contracting practices at the state level, to which PURPA provides the federal backstop, are necessary to provide a reliable investment climate for independent market participants.

3. As it stands now, under Section 292 of FERC’s regulations (18 CFR § 292), the “one-mile rule” is not rebuttable and utilities have little recourse to challenge QF projects that attempt to game this restriction. Should FERC revise its regulations to allow utilities to demonstrate that a QF developer is attempting to split a single large project into multiple smaller ones to receive the benefits of PURPA?

Due to the technological innovations, favorable economics of creating energy density in solar projects, and engineering design constraints of installing solar projects, the one-mile rule is not as applicable to solar generating sites as it is to wind generating sites. In SEIA’s experience, the one-mile rule strikes the proper balance between encouraging competition and preventing gamesmanship. The existence of a bright-line rule, such as “one-mile” rule, is essential to the development of independent power projects; the alternative in many instances would be an inability to know or to represent to lenders with certainty what the project status was.

As the developers of an independent power project explained to FERC: “We do know one fact: If the Commission rewrites its rules so as to permit such challenges, opponents will be given a blueprint for how to kill numerous qualifying facilities by delay, without regard to the merits. Indeed, this docket is a poster child of the havoc a determined opponent can create, even under the current rules, regardless of the legal merits or the underlying claim, and at very low cost to itself.” Such a result would be inconsistent with PURPA’s stated purpose to “encourage cogeneration and small power production.”

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2 See Answer in Opposition by Wasatch Wind Intermountain, LLC to Xcel Energy Services Inc.’s Request for Rehearing at 3, Docket No. EL11-51, et al. (Apr. 25, 2012).

For these reasons, Congress reserved the determination of what constitutes a QF to FERC. If Congress gives state commissions the role of patrolling the one mile rule, they could undermine PURPAs’ mandates, and create ambiguities that could weaken the investment climate for independent power. Congress should support the bright line determination and maintain FERC’s exclusive authority whether a project is properly categorized as a QF.

4. You testified that QFs are being offered unfinanceable contract terms, curtailment practices, discriminatory interconnection processes, and unreasonable avoided cost rates. What is a financeable term in your view? What changes do you want to see and who should make them (Congress or FERC)?

In FERC’s Order No. 69, FERC designed the regulations to implement PURPA, explaining that: “in order to be able to evaluate the financial feasibility of a cogeneration or small power production facility, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility.”

Small renewable projects require significant initial capital outlays upfront (often in the millions to tens of millions of dollars) that are financed and repaid over time, but have low variable O&M costs and lack the fuel cost component of a traditional thermal generator. The period of time required to pay back the financed project costs depends on the revenues from sales of the power produced by the project. The avoided cost, by definition, is a low price relative to other options and thus any financing contracts based on the avoided cost must be of a sufficient term to allow for a full recovery of the project costs. As explained in The Law and Business of International Project Finance, “[i]n a power project, a power sales agreement, or power purchase agreement as the purchaser calls it, is the linchpin of an energy project financing. It is from this transaction that the funds flow to pay debt service, operating costs, and an equity return. It must fulfill, therefore, the dual role of financing and operating document.” It is quite simply mathematically impossible to repay the projects’ entire costs over a two-, five-, or even ten-year period at an avoided cost rate in almost all areas of the United States. To allow a term less than sufficient to recover the cost of investment undermines the intents of PURPA to encourage independent generation.

Given that PURPA relies on the utility’s avoided-cost calculations, a level playing field for competitive generators would establish a contract term that is equal to the utility’s depreciation schedule for similar assets. In SEIA’s experience, most utilities employ depreciation schedules of approximately twenty years for solar assets, and thus a twenty year term for an independent generator establishes parity. While a twenty year term will provide independent market participants with more attractive financing terms, in SEIA’s experience independent power producers have recently been able to access financing for contracts with terms as short as twelve years. Any limitation on QF contract term should be mirrored by limiting the rate recovery schedule for utility’s self-built generation.
Together, Congress and FERC should reaffirm that PURPA is a commitment to competition by independent generation. Congress should either itself, or instruct FERC, to establish the minimum terms of a financeable QF contract, which should include:

a. **Financeable Term:** Shorter terms simply do not provide the stability that financial investors require to provide project financing.

b. **Fixed Price:** A predictable stream of revenue from the project asset is the fundamental basis of any project financing.

c. **Limited, Non-Discriminatory Curtailment:** Curtailment by buyers must be limited to narrow circumstances and must be imposed in a non-discriminatory manner.

d. **Equitable Security Requirements:** SEIA members have observed a specific manifestation of this issue: one utility operating in multiple states mandated that the QF accept a development security provision that provided the host utility – not the lenders, as is traditional – would be able to seize the project in the event of a default. The utility insisted on the provision, and the developer was forced to abandon the project. In terms of general principles, Congress and FERC should affirm that utilities cannot engage in such unfair trade practices.

e. **Equitable Interconnection Practice:** Congress should require that the Commission take an active role in ensuring that incumbent utilities, particularly multi-state utility companies operating outside of an organized market, are not using the interconnection process as a guise to prevent competition from independent market participants. FERC should consider the interaction of a PPA and the interconnection process and, at a minimum, provide the developer with the ability to renegotiate the PPA and/or allow for an expedited dispute resolution process at FERC where a developer believes that a utility is applying the interconnection process in a discriminatory fashion.

5. If PURPA was no longer in effect, how do you think it would affect consumer electricity rates and the future development of renewable energy, cogeneration facilities, and waste-to-energy facilities?

While the discussions concerning PURPA reform have focused on the mandatory purchase obligation, it is essential to note that the other provisions of PURPA provide key exemptions to support capital market financing. Repeal of these exemption provisions could cause substantial disruption for both projects under existing financing arrangements as well as new projects seeking financing.
If PURPA’s mandatory purchase obligation was repealed, SEIA believes that the regulatory environment would then allow a reversion to the monopolistic and oligopolistic practices that governed a non-competitive market for wholesale electricity – just as they did before 1978. If PURPA’s mandatory purchase obligation was repealed, competition would be significantly disadvantaged if not extinguished, and consumers would not be denied the full benefit of an reliable, resilient grid that utilizes advanced technologies. States and state commissions should not be able to forestall such a result. Indeed, that is why Congress passed PURPA.

**Responses to the Additional Questions for the Record Posed by the Honorable Frank Pallone, Jr.**

1. **As it relates to solar energy procurements for PURPA and non-PURPA contract agreements, how common are long-term contracts exceeding 20 years?**

   In SEIA’s experience, it is not standard to have a contract term exceeding 20 years. Contract terms at 20 years, however, are standard for both PURPA and non-PURPA contract agreements. Some very large solar and other renewable projects have been able to secure 25 year contracts because the capital costs are quite large and the benefits to the buyer in the later years are sufficient to warrant a longer term. Generally, the term of the PPA must be no longer than the economic life of the facility.

2. **What benefits do ratepayers receive when utilities enter into fixed-price contracts? How do these benefits compare to the benefits of self-built generation?**

   Wholesale competition in electricity was initiated and expanded through a succession of federal rules beginning with PURPA. Wholesale competition brings savings to ratepayers through the use of economic dispatch – as each load serving entity accomplishes dispatch based on the estimated incremental (or marginal) costs to run each plant. SEIA calls attention to the often-repeated assertion that PURPA compels utilities to purchase “high cost” or “overpriced” energy. This is false; by definition, the avoided cost-based pricing of PURPA contracts can be no higher than the cost the utility would otherwise pay (i.e. the “marginal cost”). Given technological innovations – such as the rapid developments in inverter technologies over the past three years directly attributable to PURPA – solar based energy generation is cost competitive with fossil fuel-based avoided cost calculations.

   Purchasing from qualifying facilities under PURPA provides savings, certainty, and places value on consumers preferences and interests. Bringing PURPA projects on-line, at the avoided cost, drives down the system marginal cost and thus reduces the cost to serve both wholesale and retail customers. In addition the ratepayers do not bear any risk for cost overruns in project construction or ongoing operations and maintenance expenses. This should be contrasted to the risk ratepayers bear for utility-owned generation, such as the billions of dollars residents of Georgia will be asked to pay to cover the cost overruns at the Vogtle nuclear plant, the hundreds of millions in coal ash cleanup costs that the residents of North Carolina are being asked to cover, or the ill-fated Shoreham Nuclear facility that Long
Islanders are still paying for today. These types of situations are the same as those in the 1970s that led to Congressional enactment of PURPA.

In addition to cost savings, resiliency, and certainty, PURPA projects provide consumers with choice and access to innovative technologies. The vertical monopoly structure has resulted in little innovation. Today's consumers desire choice in the provision of electricity, and PURPA provides the federal backstop to ensure that every resident across the country can benefit from affordable and reliable renewable generation.

3. How does the solar industry address the interconnection costs that are associated with the QF projects?

In most cases, QFs pay for their interconnection costs under the standard interconnection cost allocation procedures that apply to all interconnecting generators. In some cases, the utilities take on such costs and allocate them to the QF as part of the avoided cost rate. In such cases, a properly computed avoided cost should include all system interconnection costs, with the project developer responsible for paying all costs to connect the generating unit into the utility's transmission or distribution system.

In SEIA's experience, utilities can engage in discriminatory practices because they control the interconnection process. To discourage such discriminatory practices, FERC should prohibit a utility from requiring a QF to either (1) construct, or assume cost responsibility for, any upgrades required for deliverability or (2) purchase long-term transmission from third parties. In addition, the utility should be required to apply the same technical standards for interconnection to both competitive and utility-owned generators.

4. How do you recommend state public utility commissions incorporate QF development into state resource planning?

Not all states have a standardized approach to resource planning, nor does each state require all electric utilities subject to the PURPA-purchase obligation to receive approval for annual integrated resource plans. Each state could benefit from a standardized set of parameters to re-evaluate economic dispatch assumptions given the continued growth of zero marginal cost resources and an increased penetration of generation on the distribution system and behind customer meters. As states evaluate whether system efficiencies (e.g., reduced line losses) can be achieved through improved dispatch, a state can ensure that the avoided cost is properly computed. A properly computed avoided cost provides an accurate economic signal to competitive generation providers as to (1) the amount of new generation needed to serve load; and (2) the locational value of the generation.
Ms. Kristine Raper  
Commissioner  
Idaho Public Utilities Commission  
472 West Washington Street  
Boise, ID 83702

October 23, 2017

Dear Ms. Raper:

Thank you for appearing before the Subcommittee on Energy on Wednesday, September 6, 2017, to testify at the hearing entitled “Powering America: Reevaluating PURPA’s Objectives and its Effects on Today’s Consumers.”

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Monday, November 6, 2017. Your responses should be mailed to Allie Bury, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Allie.Bury@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton  
Chairman  
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment
November 6, 2017

To the Honorable Fred Upton:

Thank you for allowing me to appear and testify before the Subcommittee on Energy on September 6, 2017, at the hearing entitled “Powering America: Reevaluating PURPA’s Objectives and its Effects on Today’s Consumers.” Enclosed are my responses to the post-hearing questions presented by you, the Honorable Richard Hudson and the Honorable Bobby Rush.

Please feel free to contact me if you have any further questions.

Sincerely,

Kristine Raper

Located at 472 West Washington Street, Boise, Idaho 83702
Telephone: (208) 334-2898  Facsimile: (208) 334-5762
Response to Additional Questions for the Record
November 6, 2017

Response to the Honorable Fred Upton:

1. State policies are driving growth in renewable generation. Renewable Portfolio Standards (RPS), tax credits, competitive procurement requirements, and net metering programs are just a few of them.
   a. In light of these more recent pro-renewable policies and mandates (since 1978), do we still need PURPA to drive renewable development?

   The short answer is NO. In fact, in some areas, PURPA is driving cost-effective renewables out of the market. A utility that is overwhelmed with “must-purchase” PURPA power does not have the opportunity to issue a Request for Proposal (RFP) to add renewable energy to its resource mix based on a least-cost bidder. What’s more, projects that are not chosen through the RFP process can become QFs and force their generation to be purchased.

2. If we set aside PURPA for a moment, do you believe that state policies (including integrated resource planning (IRP), competitive procurement requirements, net metering, and renewable portfolio standards) are stable enough to provide a reliable investment climate for renewable generation?

   Yes – with the caveat that I am an attorney, not an investment expert. State policies supporting the use of renewable generation have been in place for more than a decade and are only gaining momentum. In organized markets (PJM, MISO), renewable projects in excess of 20 megawatts (MW) are presumed to be competitive – and, therefore, must enter the market outside of the benefits provided by PURPA (Energy Policy Act of 2005). Although my State’s utilities are not part of an organized market, renewable generation does not seem to be suffering in those markets. In addition, all of the recent research shows that the cost of building renewable generation has come down significantly. Lower costs allow renewable technologies to be competitive with more traditional-type resources. Moreover, utilities are responding more to customer preferences. Customer preference seems to support and promote the use of more renewable generation.
3. Your Commission recently reduced the contract length for QFs in Idaho to just two years. QFs will argue that two years is not a sufficient length of time to enable the QF to secure financing. How do you respond? How did you pick two years?

QFs do argue that two years is not sufficient to secure financing. However, they never actually present their books for verifiable proof of what contract term is needed to secure financing. As a regulator, I have not yet been presented with a case where a QF shows evidence of what is needed for financing – even in our lengthy and comprehensive docket when we reduced the contract length to two years. In addition, FERC regulations require both that ratepayers are not harmed by the purchase of QF power and that QFs are not subject to discrimination. The regulations do not require that a state commission approve contract terms to make a PURPA project financeable without regard to the impact on ratepayers.

The term of a QF contract should not matter as long as the federal “must-purchase” requirement remains. The renewal of a shorter term contract allows avoided cost rates to be updated periodically so that ratepayers are not harmed. The utility’s ongoing obligation to purchase the QF power does not change.

The Idaho PUC chose two year PURPA contracts because it reasonably corresponds with the utilities’ IRP cycle – when each utility reevaluates what resources will be needed over the long term to reliably serve customers. Matching contract length with the IRP cycle reduces price risk and provides more forecast certainty for the utility and the QF.

a. As a state regulator, are you permitted to examine the QF’s books and records, as you would be able to for a regulated utility to verify costs?

NO. We are not entitled to review a QF’s costs or projected profit when considering approval of a PURPA contract.

4. In your testimony, you noted that in 1978 battery storage on a utility scale did not exist, but that it should now be eligible for QF status under PURPA. Do you consider energy storage to be a renewable resource that would qualify as a QF under the law?

FERC has actually acknowledged that neither the statute nor the rules identify energy storage/battery storage as a renewable resource eligible for QF status and, therefore, the benefits of PURPA. However, in a single decision issued in 1990, FERC includes battery storage as a renewable resource for purposes of QF certification, but not without limitation. FERC clarified that energy storage facilities are not renewable resources/small power production facilities per se. As a State commission, we are bound by the language of the FERC decision.

If my testimony included an assertion that battery storage should be eligible for QF status under PURPA, I misspoke. I do believe it is time to consider whether energy storage reasonably fits within the intent of PURPA. Battery storage facilities do not generate energy. The primary energy source behind the battery storage is the actual generation resource. As currently written, I do not believe that energy storage should be presumed to be a renewable resource/small power production facility contemplated by the Act.
a. Would a legislative change be necessary to update PURPA?

Yes. The “must-purchase” obligation is rigid and prohibits states from responding to local and regional circumstances, including considerations of reliability. Disaggregation of QF projects, which are contrary to the intent and spirit of PURPA, also need to be addressed. Finally, there is no statute of limitations proscribing how long a QF has to file a complaint with FERC against an adverse decision made by a state commission. State decisions deserve a determination of finality after a reasonable time.

5. As it stands now, under section 292 of FERC’s regulations (18 CFR § 292), the “one-mile rule” is not rebuttable and utilities have little recourse to challenge QF projects that attempt to game this restriction.
   a. Should FERC revise its regulations to allow utilities to demonstrate that a QF developer is attempting to split a single large project into multiple smaller ones to receive the benefits of PURPA?

Yes. Ignoring developers who game the system burdens ratepayers unnecessarily, negatively impacts reliability, and undermines the intent and spirit of the Act.

6. State public utility commissions are generally closer to the needs of their consumers than federal agencies. Under PURPA, FERC determines whether a QF meets its basic requirements (e.g., using its one-mile rule), and how avoided costs should be generally set, leaving the specific details to the states.
   a. Are there any areas of PURPA where the states need more ability to make local decisions?

Yes. Allowing the states a factual review of any grouping of QF projects would readily reveal disaggregation and gaming of the Act. States need the flexibility to be able to determine when a utility is overwhelmed with a “must-purchase” resource. In order to ensure reliability of the electric grid, curtailment parameters could also be set.

7. How can FERC support states in implementing PURPA in a way that works for its customers?

FERC can support states by allowing the states discretion in implementing FERC’s truly broad regulations based on local considerations and circumstances. As written, FERC’s regulations would allow for broader discretion by the states. However, when QFs file complaints with FERC, the declaratory orders issued are often narrow interpretations of the broadly written rules.

Response to the Honorable Richard Hudson:

1. This hearing comes down to fairness and transparency in electricity rates. Consumers are too often paying for technologies that have little to do with generating cheap and
reliable electricity. That is why I introduced H.R. 1572, the "Ratepayer Fairness Act," which amends PURPA section 111(d) to require that state public utility commissions consider a fair and transparent process when reviewing requests to subsidize "customer-side technologies" — or technologies that only benefit a few users, but are paid for by everyone else. Commissioner Raper, do you agree that fairness and transparency are critical to electricity ratemaking? And, as the only state public utility commissioner on the panel, can you talk about how consumers would benefit from increased fairness and transparency in the ratemaking process?

Fairness and transparency are very important in the ratemaking process. Although, as your question points out, fairness is somewhat relative depending on what side of each issue you fall. Economic fairness is paramount. The economics are often obscured by varying special interests. Consumers benefit from increased fairness and transparency in the ratemaking process by better understanding where their energy comes from — which allows them to be more deliberate in their use. It can help consumers lower their energy bills. Reducing peak demand for energy can help the utility delay construction of new generation — which also reduces the cost to consumers. Transparency in the process allows consumers to participate in a meaningful way as a utility plans for the future needs of its customers.

Response to the Honorable Bobby Rush:

1. What happens as a result of long-term avoided costs forecasts underestimating future utility costs?

If contracts are entered when long-term avoided cost forecasts underestimate future utility costs, the generator is paid pursuant to the terms of the contract. However, the more PURPA power that is contracted by the utility, the more the rates will decline. Avoided cost rates are based on a calculation of the value of the energy to the utility. The more energy that is available, the lower the value it is to the utility. Based on this practical reality, fixed long-term contracts will inevitably overestimate future avoided costs.

   a. Under these circumstances, are QFs still obligated to deliver power over the duration of the contract term?

Yes. Most contracts contain a liquidated damages clause if the QF fails to perform — although there is little a utility can do to recover damages from a QF if the QF is not generating energy to produce revenue.

2. Investor-owned utilities are permitted to recover costs, including a return on equity for self-built resources over extended periods of time.

   a. How do utilities justify these resource decisions to the Idaho Public Utilities Commission?
A utility cannot recover the costs of a self-built resource from ratepayers until the state utilities commission determines that the resource is “used and useful.” Integrated Resource Plans are used to show how long a utility is energy and capacity sufficient. The IRP also addresses changes in peak loads, customer growth, etc. The continued economic operation of a utility plant is perpetually reviewed and considered by the state regulatory authority.

b. **Does the Commission evaluate the impacts to ratepayers based on long-term avoided cost analyses, similar to QFs?**

No. If additional generation is needed the utility presents an analysis to the commission of the most economic way to meet its customers’ needs. Prior to recovery from ratepayers, the utility must show that the resource is used and useful. The utility then has an ongoing obligation to show that it is dispatching its resources in the most economic way possible. If a utility overbuilds what is needed to reliably serve its customers, it is the commission’s responsibility to only allow recovery from customers for the portion that is used and useful. A key difference between utility resources and QFs is dispatchability. The utility does not have an option to dispatch QF energy. The utility must take the energy whenever the QF generates it.

c. **Do ratepayers assume the risks of project cost overruns or errors that are made in the cost estimates provided by utilities?**

No. State commissions have the authority to review all costs and expenses for prudency. In reality, cost overruns can occur. But the reasonableness and prudency of expenses incurred by the utility are always reviewed by the state commission prior to inclusion in rates.
Mr. Stephen Thomas
Senior Manager, Energy Contracts
Domtar Paper Company
545 Whitehead Court
Fort Mill, SC 29708

Dear Mr. Thomas:

Thank you for appearing before the Subcommittee on Energy on Wednesday, September 6, 2017, to testify at the hearing entitled “Powering America: Reevaluating PURPA’s Objectives and its Effects on Today’s Consumers.”

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Monday, November 6, 2017. Your responses should be mailed to Allie Bury, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Allie.Bury@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment
November 6, 2017

The Honorable Fred Upton
Chairman
Subcommittee on Energy
Committee on Energy and Commerce
2183 Rayburn House Office Building
Washington, DC 20515

The Honorable Bobby Rush
Ranking Member
Subcommittee on Energy
Committee on Energy and Commerce
2188 Rayburn House Office Building
Washington, DC 20515

Re: Responses to Questions Relating to the Hearing “Powering America: Reevaluating PURPA’s Objectives and its Effects on Today’s Consumers”

Dear Chairman Upton and Ranking Member Rush:

On behalf of Mr. Stephen Thomas, Senior Manager of Energy Contracts at Domtar Paper Company and the Industrial Energy Consumers of America (IECA), we are pleased to provide you with the following responses to your questions.

1. State policies are driving growth in renewable generation. Renewable Portfolio Standards (RPS), tax credits, competitive procurement requirements, and net metering programs are just a few of them. In light of these more recent pro-renewable policies and mandates (since 1978), do we still need PURPA to drive renewable development?

PURPA, by itself does not “drive” renewable energy. Financial incentives and mandates drive renewable energy.

That said, PURPA is essential to ensuring that non-incumbent renewable energy project developers have non-discriminatory access to the grid, especially in tightly regulated markets. PURPA supports competition among electric generators. And, competition supports lower rates for all consumers.

PURPA simply provides the vehicle for renewable energy projects to connect to the grid and the mechanism that determines how much they get paid. That mechanism is the electric utilities’ “avoided cost”.

Renewable energy projects are paid the “avoided cost” which is determined by the state public service commission. The avoided cost is the same cost as if the incumbent utility builds the generation. If the avoided cost is calculated properly, other consumers will not pay more for the renewable energy electricity. We find large variances from state to state. In our opinion, some states pay too low an avoided cost and too high in others. Importantly, these decisions are made by the state and not at FERC.
2. If we set aside PURPA for a moment, do you believe that state policies (including integrated resource planning (IRP), competitive procurement requirements, net metering, and renewable portfolio standards) are stable enough to provide a reliable investment climate for renewable generation?

Yes, for those states that offer a range of options. No, for the states where the regulatory environment is not supportive of renewable energy. The differences can cause clusters of renewable energy generators that can create an uneven distribution of load and generation on the interstate electric grid, thereby making the managing of grid reliability artificially more difficult.

3. In your testimony, you make clear that industrial QFs are different than intermittent QFs and that those QFs should be curtailed before your manufacturing processes are impacted. What would be your proposal to address this issue?

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. The remaining generation on the system will be QFs, nuclear, hydro and some natural gas generation. Since it is not practical to curtail hydro or nuclear, the next choices are QFs and the remaining natural gas generation units.

IECA believes that 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 facilities are 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. Therefore CHP/WHR QFs should not be curtailed below a net zero export position.

In the reverse situation where the grid becomes unstable because there is insufficient generation to meet instantaneous demand, 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 shut down 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 shining, “all” of the turbines in the region are not turning/generating electricity and/or all of the solar panels 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).

4. If PURPA was no longer in effect, how do you think it would affect consumer electricity rates and the future development of renewable energy, co-generation facilities, and waste to energy facilities?

For renewable energy

It depends on the state. In some states, because of high renewable energy subsidies and mandates, renewable energy might be able to out-compete more traditional generation in the short run. In many cases, subsidized renewable energy generation is already contributing to the premature retirement of existing base load generation.

The fear is that once the subsidies end, the newly unsubsidized units will set a price for energy and capacity that is higher than the traditional units that have already been retired. The extra cost then, whether in a market-based or regulated system, gets passed onto end use consumers, including industrial and residential customers.

This could even be exploited by utility investors that actually make higher returns on new, higher priced generation than they do on existing lower-cost traditional generation or fully-capitalized generators that are still reliable and inexpensive energy producers.

For new CHP/WHR facilities

Since manufacturing companies are in the business of making products and not power, without the regulatory and non-discriminatory guarantees offered by PURPA, many manufacturing companies would not invest in the capital required to install and operate CHP/WHR facilities.

There would also be other residual impacts as well. In most cases, the energy created by co-generation facilities is a by-product, so the production of no cost or low-cost energy reduces rates for all other customers. And, the distributed nature and high-capacity factor of these generators improves overall grid reliability. Both benefits would potentially be lost to retail consumers.
For existing CHP/WHR facilities

Without PURPA, and in regulated markets, with time, and as contract agreements between CHP/WHR facilities and local utilities expire, there will be an incentive for the local utilities to either not renew the agreements or with terms that could substantially increase the costs to the CHP/WHR facility. It is important for policymakers to remember the interconnection is a monopoly and we do not have a choice of going elsewhere for the service of interconnection and standby power at just and reasonable rates. As a result, electric costs to the industrial facility would increase. And, rates to retail electric consumers would likely go up as well. It is critically important that industrial CHP/WHR facilities should have the right to extend their contracts at the utilities’ avoided cost.

Sincerely,

Stephen Thomas, PE
Senior Manager, Energy Contacts
Domtar Corporation

Paul N. Ciclo
President
Industrial Energy Consumers of America

The Industrial Energy Consumers of America is a nonpartisan association of leading manufacturing companies with $1.0 trillion in annual sales, over 3,400 facilities nationwide, and with more than 1.7 million employees worldwide. It is an organization created to promote the interests of manufacturing companies through advocacy and collaboration for which the availability, use and cost of energy, power or feedstock play a significant role in their ability to compete in domestic and world markets. IECA membership represents a diverse set of industries including: chemical, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, building products, brewing, independent oil refining, and cement.
Mr. Terry Kouba
Vice President, Iowa Operations
Alliant Energy
1031 Iowa Street
Dubuque, IA 52001

Dear Mr. Kouba:

Thank you for appearing before the Subcommittee on Energy on Wednesday, September 6, 2017, to testify at the hearing entitled “Powering America: Reevaluating PURPA’s Objectives and its Effects on Today’s Consumers.”

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

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Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment
Questions for the Record

Submitted by Terry Kouba-Vice President Iowa Operations Alliant Energy

1. State policies are driving growth in renewable generation. Renewable Portfolio Standards (RPS), tax credits, competitive procurement requirements, and net metering programs are just a few of them.

   a. In light of these more recent pro-renewable policies and mandates (since 1978), do we still need PURPA to drive renewable development?

Chairman Upton:

No, Alliant Energy believes that PURPA has outlived its usefulness in promoting cost-effective, renewable energy deployment in the United States. This is especially true in Iowa where 36% of the state’s electricity mix is generated from wind, a statistic to which Alliant Energy is a proud contributor. Absent a full repeal of PURPA, Congress and FERC can nevertheless take steps to improve implementation, mitigate negative impacts on customers and the grid, and better reflect current market conditions by modernizing the law.

While states across the country—in organized or unorganized markets—are able to competitively solicit renewable energy, electric companies are still subject to PURPA’s outdated mandatory purchase obligation. The price paid for this energy is often administratively determined, and project locations are chosen for the benefit of the investor of the Qualified Facility (QF), not the customer, which has led to increased electricity costs for our Iowa customers.

Alliant Energy notes that all QFs in the Midcontinent Independent Systems Operator (MISO) footprint have the opportunity to interconnect directly to the transmission system as an independent power producer and participate in the market. Many QFs could take advantage of the processes available in MISO that allow a small generator of 5 MW or less to use MISO’s Fast Track Process in its Tariff (Attachment X) to interconnect directly to the transmission system. However, QF developers in Alliant Energy’s Iowa service territory have frequently opted out of connecting directly to the transmission system and directly participating in the electricity markets available to them.

2. If we set aside PURPA for a moment, do you believe that state policies (including integrated resource planning (IRP), competitive procurement requirements, net metering, and renewable portfolio standards) are stable enough to provide a reliable investment climate for renewable generation?

Chairman Upton:

The environment in which Congress originally enacted PURPA in 1978 is vastly different from the ways in which energy is produced and used today. Improvements in technology have significantly
lowered the cost of installing wind and solar energy. Additionally, state-level policies such as Renewable Portfolio Standards, changing customer expectations, and societal demands have all helped create a new energy environment. As a result of these changes, generation from renewable energy resources, such as wind and solar, has increased substantially since PURPA was enacted, and that trend shows no sign of slowing. In 1978, robust energy markets like MISO did not exist. Now, about half of newly constructed renewable generation capacity in the United States participates in energy markets that provide clear price signals and competition.

Alliant Energy’s commitment to deploying cost-effective renewable resources is strong: we currently have more than 1,000 MWs of wind capacity from existing wind farms purchase power agreements, and are in the midst of executing a plan to install up to an additional gigawatt of wind resources – an investment of approximately $1.8 billion. By 2030, we have a target to reduce our fossil-fueled generation carbon dioxide (CO2) emissions by 40 percent from 2005 levels. Renewable energy investments will play a significant role in our generating fleet’s transformation given the declining costs and demands of our customers.

3. As it stands now, under section 292 of FERC’s regulations (18 CFR § 292), the “one-mile rule” is not rebuttable and utilities have little recourse to challenge QF projects that attempt to game this restriction.

   a. Should FERC revise its regulations to allow utilities to demonstrate that a QF developer is attempting to split a single large project into multiple smaller ones to receive the benefits of PURPA?

   Chairman Upton:

   Yes, FERC should allow energy companies to challenge abuses of FERC’s “one-mile rule” as described in my written testimony. Reform of FERC’s “one-mile rule” is a critical component in stopping abuse of PURPA regulations, which lead to higher energy costs for our customers.

   Under FERC’s implementation of PURPA, Alliant Energy and other utilities are not able to challenge the presumption when larger resources are divided into separate entities in order to qualify as QFs under PURPA. The one-mile rule provides the safe harbor of an irrebuttable presumption to QF facilities, eliminating the opportunity for my company to make a case to FERC that these projects are gaming the Commission’s own regulations.

   Our customers are currently paying $20 million in additional costs under PURPA. Without reform, our customers could potentially pay up to a 50% price premium for QF-generated wind energy in Iowa.

4. We’ve heard about situations where a host utility has no need for additional power, but are nevertheless required to purchase the QF output under section 210 of PURPA (i.e., the mandatory purchase obligation).
a. How does a utility respond in these types of situations?

Chairman Upton:

Energy companies have little recourse under section 210 of PURPA, but to take QF output regardless of whether the utility has a need for the generation capacity. Although Alliant Energy has not experienced this particular situation to date, our company and industry would like the ability to avoid entering into QF contracts in instances where our customers do not have a need for more generation capacity in a given year. Congress should consider legislative fixes to this issue.

b. Should state commissions be able to suspend the mandatory purchase requirement in situations where it determines that the utility does not need the QF output in order to meet its obligation to serve load?

Chairman Upton:

Yes, state commissions should have flexibility regarding the mandatory purchase obligation in situations where a utility does not need a QF’s output. Congress should consider exempting utilities from PURPA’s mandatory purchase obligation if a state regulatory commission finds that: (1) the utility’s customers do not need the additional power to meet their customers’ needs; or (2) the utility employs integrated resource planning and conducts a competitive resource procurement process that provides an opportunity for QFs to participate in the procurement process.
Mr. Darwin Baas
Director
Department of Public Works for Kent County, Michigan
1500 Scribner, N.W.
Grand Rapids, MI 49504

Dear Mr. Baas:

Thank you for appearing before the Subcommittee on Energy on Wednesday, September 6, 2017, to testify at the hearing entitled “Powering America: Reevaluating PURPA’s Objectives and its Effects on Today’s Consumers.”

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Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment
November 6, 2017

The Honorable Fred Upton, Chairman
Subcommittee on Energy
House of Representatives
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington DC 20515-6115

Dear Representative Upton,

Below are responses to the questions sent in your letter dated October 23, 2017:

1. State policies are driving growth in renewable generation. Renewable Portfolio Standards (PRS), tax credits, competitive procurement requirements and net metering programs are just a few of them.
   a. In light of these more recent pro-renewable policies and mandates (since 1978), do we still need PURPA to drive renewable development?

   Yes, PURPA is still needed to drive renewable waste-to-energy investment, and importantly, to provide markets with equitable energy (and capacity) pricing and terms for existing waste-to-energy facilities.

   Not only does PURPA need to be retained, it needs to be strengthened. As currently implemented, in a patchwork and disparate fashion, PURPA is failing in its goal to provide non-discriminatory access for renewable WTE facilities. Even with PURPA, WTE facilities face discriminatory pricing, including the use of spot market pricing to set avoided cost, discriminatory avoided cost calculations, and the exclusion of capacity from the calculation of avoided cost. In many markets, WTE QFs face a choice: a power-purchase agreement based solely on a spot market energy supply price, or exposure to a variable market with some provision for capacity. However, where capacity markets do exist, they are still relatively short-term and, importantly, do not account for environmental externalities or the full range of system benefits provided by small baseline QFs.
Only one green-field waste-to-energy project has been developed in the U.S. in the last 20 years, while attempts to develop projects for and with local governments have failed due to a lack of adequate energy pricing, despite state policies. Similarly, existing WTE facilities have closed in that same timeframe despite their development under PURPA.

Not every state has an RPS, and each state has variable renewable content requirements, timelines and technologies, creating a patchwork of policy that fails to result in a robust renewable energy market. RPS programs like Michigan, with a 10% goal, are too small to effectively add real value to energy pricing of existing facilities, and only meet a fraction of the state’s existing renewable output. More robust programs are often oversubscribed by facilities located in states without renewable programs.

Few states that I am aware of have tax credits for new or expanded facilities, and federal tax credits to date have not been effective for WTE. First, despite eligibility for the renewable energy tax credits, the intermittent nature of those tax policies has left WTE facilities unable to access the credits. Additionally, nearly half the WTE facilities in the U.S. are owned by local governments, making them ineligible for a tax credit. For example, all six expansions of existing WTE facilities constructed from 2007-2014 were owned by local governments, which means none benefitted from federal tax credits.

Similarly, net metering programs, while potentially a significant option for WTE power “sales”, have not proven to be useful for WTE, despite the local government partnership in these plants. Utility wheeling charges, penalties, or other obstacles prevent WTE facilities, even those owned by local governments, from delivering power to other local government infrastructure, such as waste-water treatment facilities or government office buildings, or to local manufacturers.

In competitive markets, energy pricing is driven by historically low natural gas pricing, and value is seldom given for attributes like base load power delivery, fuel diversity or resilience. Capacity is also often uncompensated, or in those areas of the country with capacity markets, priced far below what is needed to ensure long-term supply. These circumstances are true for WTE facilities around the country, even those like Kent County which are still PURPA-eligible facilities.

New deployment of WTE, with or without local government involvement has stalled in the US even where PURPA provisions still apply. Without stronger PURPA provisions, new deployment is unlikely and existing facilities will grow increasingly stressed, as have the many that have closed.
2. If we set aside PURPA for a moment, do you believe that state policies (including integrated resource planning (IRP), competitive procurement requirements, net metering and renewable portfolio standards) are stable enough to provide a reliable investment climate for new generation?

No. These state programs do not exist in every state, and there is not a level playing field among renewables, even in states with policies to support renewables. Public policy narrowly focused on new deployment or lacking in parity among renewables creates disadvantages and undermines the viability of existing renewable facilities, especially those with on-going operating expenses. The end result is a failure to create a reliable investment climate for all technologies.

Without restoration of meaningful PURPA provisions for baseload QFs like WTE, there will be a winnowing or contraction of baseload generation capacity. The emphasis on gas (given its low price and role as a backup for intermittent renewable power) and layered incentives for intermittent renewables are creating a market bias, as renewable baseload options like WTE are pushed out.

3. In your testimony, you state that Waste-to-Energy QFs are facing particular hurdles that are different from those faced by renewable QFs. Can you explain in greater detail? Is this an avoided cost problem?

A significant challenge faced by WTE QFs is avoided cost – how it is defined, what it includes, how it is applied by utilities and state public service commissions and who is eligible for it. Not only is it applied differently from state to state, but as noted in comments to FERC, a Florida WTE QF was offered a different avoided cost price by a utility for the same energy offered via a different entity. However, the problem is also that the markets discriminate against WTE facilities above 20 MW in both open and closed energy markets.

Waste-to-energy facilities are unique in that that are not pure play energy producers. They are dual purpose municipal infrastructure that is either owned by a local government, or is a public-private partnership arrangement, which is owned by a private entity, but operated on behalf of and in the service of local governments.

Building a facility requires the developer and local government customer to comply with local government procurement laws (and the public hearing and approval processes involved with that) in addition to the typical processes required of other renewables. This adds time to development of new facilities, making it difficult for them to take advantage of federal tax credit programs with one or two year eligibility windows.
WTE plants (or its long term service) are “bought” by a local government based on a public service need, and are not developed solely to provide power to the grid. As such, the cost of this product must be identified and contractually guaranteed to the local government prior to their commitment to purchase it. These plants are not typically developed independent of that customer, and the factors that determine whether or not to develop a project go well beyond those applied to other renewable technologies.

Unlike other renewable technologies, WTE facilities compete in two markets – energy and solid waste. On the energy side, WTE facilities must compete against low natural gas prices, or other renewables that can take advantage of short-lived tax programs and layered renewable incentives. On the solid waste side, the local government has to compete with inexpensive and abundant landfills, as they lack the flow control to manage the material for which they are required to provide infrastructure. Without adequate energy pricing—whether competitively bid or as part of PURPA QF pricing provisions—these facilities can be forced to operate at a loss to keep providing the public service. Alternatively, they may need to close prematurely when energy revenues are no longer adequate to invest in routine maintenance investments.

Despite often owning the asset, local governments are unable to use the power they generate to meet the energy needs of other local government infrastructure or businesses. In fact, local governments typically have few options for selling their WTE QF power. Furthermore, WTE facilities must run to provide a continuous and reliable solid waste service to the communities they serve. Utilities understand this, and use this as leverage in energy pricing negotiations. Without alternative options for power sales, or policies requiring compensation for resiliency, diversity and secondary public services, prices will continue to be a race to the bottom and the risk of infrastructure failure will increase.

4. If PURPA was no longer in effect, how do you think it would affect consumer electricity rates and the future development of renewable energy, cogeneration facilities and waste-to-energy facilities?

With today’s limited PURPA provisions, almost no new WTE development or expansion has occurred in the US in two decades. This is in contrast to Europe and Asia, where significant development as occurred due to public policy which supports local governments’ efforts to provide sustainable infrastructure. If PURPA was no longer in effect, that stagnation would most certainly continue. Additionally, existing facilities like Kent County, which are currently covered by PURPA, would face increased risk of
premature closure, stranding local government infrastructure and investments. Without additional PURPA provisions, existing WTE facilities across the country – whether covered by PURPA or not - are not without that risk today.

There would not likely be any positive effect on consumer electricity rates if PURPA was no longer in effect. In our experience, rates sought by utilities before state regulators for their own generation (new or existing) are higher than rates they are willing to pay for QF power, even under PURPA. There is disconnect between what they are seeking in rate cases and what they are paying as avoided cost, which often doesn’t include capacity payments even when there is a capacity market, and does not include value for any of the other benefits of WTE QFs.

However, if baseload renewable power continues to contract, and other renewables continue to deploy new generation, there could be a long-term negative financial impact if over-building is required for redundancy.

The Honorable Frank Pallone, Jr.

1. In your testimony, you suggest that the relevant utility in your state is seeking a rate increase of $172 million, on top of an additional $759 million in rate increases it has already received in the last 9 years. Yet, you suggest you are not seeing any of that increase reflected in your energy pricing.
   a. How much of the utility’s generation comes from QFs?

   We believe the accurate number is 349 MW. Kent County is a 16.8 MW facility which exports 14 MW to the grid.

   b. When must you sign a new contract with your utility, and do you have any indication that the utility will pass any of that new rate increase through to you in your new contract?

   No, in fact the opposite is true. The contract between Kent County and our utility will expire in February 2022. Attempts to begin contract discussions have been unsuccessful. We are aware, through filings made by the utility that they intend to move to a year to year contract with Kent County. They have also indicated their intent to define avoided cost as wholesale natural gas pricing, which represents a 24% reduction in price for our power that is supported by the MPSC.

2. You state in your testimony that "avoided costs" paid to waste-to-energy QFs should include the value of environmental and energy benefits, such as baseload generation,
the diversity of generation, proximity to load centers, greenhouse gas mitigation, resiliency and for being municipal infrastructure.

a. Are these attributes not part of the current cost calculation?

No. Because the utility is the only option for energy sale, they have all the leverage and at times don’t even pay for capacity. In a competitive market, the price point is the driving attribute, and because no value has been placed through public policy on being resilient or baseload or serving to public functions or mitigating greenhouse gas, etc., no market value is given.

b. If Congress amended PURPA, would you recommend that these attributes be specifically identified as an element of avoided cost?

Yes, at least for WTE QFs. This would allow local governments the ability to continue to provide local government services to its citizens and to its local businesses and industries while strengthening grid resiliency and diversity. It will also help prevent unnecessary expenditures that would be required to replace this infrastructure with suboptimal alternatives that do not have the same benefits to the grid or environment.

c. Are there any other changes you would recommend?

Yes. All WTE QFs up to 80 MW should be covered under PURPA’s mandatory purchase requirements, regardless of whether they are in wholesale markets with capacity and energy components. The experience of WTE QFs around the country is that discriminatory pricing for power exists. As such, we believe Congress should modify the presumption in FERC Order 688 that certain markets offer nondiscriminatory access to recognize that this is not true for WTE QFs. Utilities know they have leverage over WTE facilities, which have no other outlet for power sales. We support mandatory purchase for WTE QFs up to 80 MW, and a minimum contract length for existing (5 years) and new (20 years). A reasonable minimum contract length would provide stable, longer term pricing, allowing local governments and owners the ability to commit to, secure financing for, or otherwise plan for routine maintenance and capital investments without fear of defaulting on longer term financing with short term energy contracts. Finally, as noted, we encourage a modernized definition of avoided cost with value for benefits including baseload, renewable power, and its municipal infrastructure role.
3. Some have argued that the rates QFs receive are above market and are set too high for fixed periods that don’t account for changes in the industry.
   a. What is your assessment, and how do you respond based on your knowledge and experience in the industry?

   As WTE QFs have rolled off their initial PURPA QF contracts, the national trend has been for subsequent contracts to be short term, or for utilities to opt out of entering into new contracts altogether, leaving WTE QFs no choice but to sell power into the grid directly in the day-ahead markets. There has also been a trend for energy revenues to consistently and significantly drop. Original PURPA contracts were set at an avoided cost rate that reflected the avoided cost of a utility to add a new megawatt of electricity, and were not above market. Today, the utility wants to interpret avoided cost as the short-term wholesale natural gas price with little to no consideration for capacity, while they simultaneously seek a rate hike and approval for a new large combined cycle gas plant at a price per megawatt higher than they’ve expressed their willingness to pay Kent County.

   b. What is your response to those who would use this position to argue for eliminating or scaling back the QF program?

   We cannot speak to the validity of this argument for all QFs, however, the assertion is not accurate for WTE QFs, and likely not for other base load QFs. Communities with WTE facilities are in the unique position of being both a generator and a consumer of power. We sell power to a utility or to the grid from our WTE plants at one price point, and buy it back to pay for our government buildings, jails, waste-water treatment plants and airports. The price differential in some cases is too great to legitimize this argument – over a 100% increase between the sale and purchase prices.

4. It has been reported that the utilities do not need power from Existing QFs, therefore low avoided cost prices are justified.
   a. Based on your experience, how would you describe utilities’ need for more electricity?

   Kent County’s experience is the opposite. While the MPSC rulings to date indicate Kent County’s power purchase price will be cut by 24%, somewhere around $.06 - $.065 per KWh, the utility is seeking PPA approval to convert a biomass plant to utility-scale natural gas facility at a rate more than $.07 per KWh.
5. Do you believe that the challenges you face with PURPA are unique to Kent County or limited to a region or market, and are you aware of similar issues on a national level?

Similar circumstances exist around the country. Other utilities are building their own energy generation at pricing that they are not applying to QFs. This is occurring not only in Michigan, but in Florida, Virginia, and elsewhere. I have attached recent FERC comments which detail these specific issues in more detail.

Warm Regards,

Darwin J. Baas
Director