UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Qualifying Facilities Rates & Requirements	)	**Docket Nos.**
	)	
Implementation Issues Under the Public Utility Regulatory Policies Act of 1978	)	**RM19-15-000 &**
	)	
	)	**AD16-16-000**
	)	
	)	
	)	

COMMENTS OF THE

NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION,

COMMUNITY RENEWABLE ENERGY ASSOCIATION

RENEWABLE ENERGY COALITION, AND

OREGON SOLAR ENERGY INDUSTRIES ASSOCIATION

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EXECUTIVE SUMMARY

The Northwest and Intermountain Power Producers Coalition ("NIPPC"), Community Renewable Energy Association ("CREA"), Renewable Energy Coalition ("REC"), and Oregon Solar Energy Industries Association ("OSEIA") (collectively referred to herein as the "Northwest Coalition") represents a broad spectrum of independent power producers, renewable energy developers, local governments, irrigation districts, and other entities who are actively involved in building electric generation and advocating on energy policy issues in the Northwest.

The Northwest Coalition strongly agrees with Commissioner Glick that the Federal Energy Regulatory Commission ("FERC" or "Commission") should be "focusing on expanding opportunities for genuine competition."[1] Instead of promoting PURPA's procompetitive goals, however, FERC's Notice of Proposed Rulemaking ("NOPR")[2] will, if adopted, "effectively gut the Public Utility Regulatory Policies Act (PURPA),"[3] and will represent a retreat from the pro-competitive policies the Commission has pursued for a full generation. Further, application of the NOPR to existing generation facilities is likely to undercut the economics of those facilities, forcing many existing PURPA facilities that have provided reliable and clean power to Northwest consumers for years or even decades to be abandoned.

I.

The Coalition believes that electric consumers, the industry, and the public interest would be best served if independent power producers ("IPPs") could compete on a level playing field with incumbent utilities in generation supply. Unfortunately, that goal remains elusive,

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1 Statement of Commissioner Richard Glick, *dissenting in part from NOPR,* at P 26.

2 Notice of Proposed Rulemaking, *Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Policies Act of 1978,* FERC Docket No. RM19-15-000 *et al.* (Sept. 19, 2019) ("NOPR").

3 Statement of Commissioner Richard Glick, *dissenting in part from NOPR,* at P 1.

especially in the Northwest. The region has no organized wholesale market structure, and instead it retains a vertically integrated utility model wherein the incumbent utilities have an inherent economic incentive to own and rate base generation resources at a profit to their shareholders, even if doing so leads to more expensive outcomes for their ratepayers. In addition, without an independently operated transmission system, the region retains a balkanized transmission system that imposes pancaked transmission rates and the risks of discriminatory treatment inherent where incumbent utilities can control access to wholesale generation markets.

In the absence of fully effective competition in the Northwest, PURPA provides a critically important backstop right for independent power producers, operating as renewable small power production or cogeneration qualifying facilities (or "QFs"), to compete against the utility's long-run marginal cost of generation – just as was intended when the statute was enacted. By effectively rendering PURPA a dead letter, the NOPR therefore represents a retreat from the pro-competitive policies FERC has pursued for the last generation. Further, the NOPR is likely to create substantial disruptions to electricity markets because it could eliminate hundreds of existing and new PURPA projects as a beneficial competitive force in the electricity markets. And it is likely to exacerbate reliability concerns because it could limit or eliminate capacity at a time when the Northwest is projected to face capacity shortages.

II.

The NOPR exceeds FERC's statutory authority. Both the plain text of the PURPA statute and its legislative history are explicit that PURPA requires FERC to adopt rules that "encourage" development of QFs. But, without any change to the foundational law, the NOPR would do exactly the opposite, subjecting QFs to a variety of costs, barriers to financing, and risks that discourage rather than encourage QF development and are not faced by incumbent utilities. The NOPR is premised on the claim that the nation now produces fossil fuels and renewable resources in such abundance that PURPA is no longer necessary, and that effective competition renders PURPA's mandates an anachronism. But if PURPA is no longer necessary, that is a judgment for Congress to make. FERC therefore oversteps its authority and usurps Congressional prerogatives in seeking to rewrite PURPA.

III.

FERC's justification for the regulatory changes proposed in the NOPR fails. FERC cites three developments to argue that PURPA is no longer needed: (i) the growth of "fracked" natural gas, (ii) state and federal incentives that promote renewable generation, and (iii) the development of competition in the electric industry. None of these developments justifies FERC's proposal to stop encouraging small power production and cogeneration QFs, as the statute still requires.

While the upsurge in natural gas production as a result of new "fracking" technologies is obviously a significant development in the industry, by itself this development does nothing to overcome barriers to competition in the Northwest electricity industry and does not change the fact that PURPA still requires FERC to encourage QFs. Policies such as state renewable portfolio standards ("RPS") and federal tax incentives affect the demand for renewables and create new options for renewable projects to be financed, whether owned by utilities or IPPs. But these policies do nothing to overcome barriers to competition that small power production and cogeneration facilities continue to face in the Northwest. The Commission cites a great deal of evidence about the growth of renewables, but none of it addresses this problem.

While there is little doubt that the Commission's own policies have advanced competition in the wholesale energy markets, there is a great deal of evidence that effective competition between investor-owned utilities and independent power producers who each seek to fund new resources has yet to develop, especially in the Northwest, which remains largely a bilateral market. In short, the NOPR provides no evidence to suggest that QFs, or IPPs more generally, now have unfettered access to wholesale energy markets, and the Commission's retreat from its pro-competitive agenda is therefore wholly unjustified.

Further, a careful review of the evidence refutes assertions relied upon in the NOPR that QFs have been more expensive than comparable resources built by incumbent utilities. FERC's conclusion that QF prices are above market prices is an artifact of the general decline in wholesale electric prices over the last decade. But there is no reason to believe that prices will continue to fall indefinitely. On the contrary, there is strong evidence that electricity prices are likely to rise in the coming decades, driven by multiple factors such as increasing demand arising from electrification of the region's transportation system. In fact, the Integrated Resource Plans for the major utilities in the Northwest predict significant growth in electricity demand and prices. In these conditions, PURPA contracts (like all long-term contracts) are especially valuable because they protect electric consumers against rising power prices and unpredictable price volatility.

The NOPR also overlooks that PURPA has resulted in the construction of numerous existing renewable energy projects in the Northwest, many of which would not have otherwise been built. This includes *hundreds* of hydroelectric, biomass, biogas, geothermal, cogeneration, diary digester, waste-to-energy, wind and solar projects *under* 20 megawatts ("MW") selling power to Rocky Mountain Power, Pacific Power, Idaho Power Company, Portland General Electric Company, Puget Sound Energy, and Avista. These include facilities owned and operated by cities, counties, irrigation districts, water districts, waste management districts, schools, universities and farmers as well as small businesses and private individuals which re-invest their power sales revenues in their local communities. These projects, some of which have been operating since the mid-1980s, generally are located in rural and economically depressed areas, and have no other option than selling power to their interconnected utility. The adoption of the NOPR will make it difficult for these existing QFs to continue to operate, and may eventually result in the shutdown of hundreds of megawatts of currently operating renewable energy generators. The NOPR completely overlooks this impact of its proposals and makes no effort whatsoever to limit such impact.

Finally, PURPA is self-correcting. If it is true that utilities do not need new capacity, the avoided cost of that capacity is zero, which should make construction of new PURPA projects economically impracticable. Similarly, if the abundance of generation has driven down the cost of energy, the avoided cost of energy should reflect those low energy prices, also making new PURPA projects economically impracticable. In other words, PURPA mimics the operation of competitive markets and, in the absence of genuinely competitive wholesale markets for electricity and coupled with a must-buy obligation when avoided costs are substantial, remains an important source of competitive pressure for utility incumbents.

IV.

FERC's proposals to repeal the requirement that utilities offer each QF a long-term PURPA contracts containing fixed-price rates should be rejected.

A. The NOPR proposes to permit long-term avoided cost rates for electric energy to be set by reference to short-term Locational Marginal Prices ("LMP") or by reference to prices in the West's emerging Energy Imbalance Market ("EIM"), which is an intra-hour, momentary market. This proposal would, if adopted, effectively eliminate the right to sell under PURPA by making it difficult or impossible to finance projects because the LMP and EIM prices are designed to encourage optimized dispatch of existing resources at or near short-run marginal cost, not to create incentives for new generation in the long-term markets. Further, by exposing PURPA projects to the risks of highly volatile and unpredictable short-term markets, the proposal would put QFs at an insuperable disadvantage compared to incumbent utilities, who can recover their rate-based, fixed costs of generation investments through traditional cost-of-service rate recovery regardless of short-run volumetric market prices.

FERC cites a good deal of evidence concerning the growth of renewable energy in recent years, but none of this evidence addresses the critical question for this aspect of the NOPR – whether generation can be financed despite exposure to volatile short-term markets. The available evidence from objective sources, such as financial rating agencies, demonstrates exactly the opposite – contracts that expose projects to market risks are highly disfavored. If such projects can be financed at all, financing will be difficult and expensive to obtain, putting PURPA projects at a huge, likely fatal, disadvantage.

FERC's proposal also incorrectly assumes that QFs will continue to be encouraged without fixed energy prices, so long as FERC still requires fixed capacity payments. There is no evidence supporting this assumption. The proposed rule would provide no assurance that meaningful capacity payments would ever be made in the first place. Experience in the Northwest demonstrates that incumbent utilities' avoided cost calculations can omit capacity payment requirements through critical and potentially strategic assumptions and rate calculation methods – especially in the early years of a long-term contract. Thus, without assurance of contract terms in the range of 15-20 years, QFs may not receive any capacity payments, much less the substantial fixed capacity payments that are necessary to provide a reasonable opportunity for recovery of, and on capital investments. In its reasoning on this point, FERC's NOPR acknowledges that some states have reduced the terms of PURPA contracts to as little as two years, but the NOPR proposes to do nothing about this problem – leaving no assurance QFs would be offered any fixed-price payments at all.

B. The NOPR also proposes to permit use of indexed prices from liquid market hubs as an alternative to set the energy component of avoided cost rates. This proposal makes sense only if indexed prices for *long-term* contracts are used to set long-term avoided cost rates, and only if those indexed prices accurately represent the long-run fixed costs avoided by the purchasing utility's purchase of power from the QF. Short-term day-ahead prices for power deliveries, such as the Mid-Columbia index proposed for use in the NOPR, do not reflect the capital costs of constructing new generation and therefore are inadequate to ensure sufficient returns to permit capitalization of new generation. Further, FERC must ensure that indexed prices are the result of genuine competition, so trading must be liquid and price indices must be transparent and free of manipulation.

C. The NOPR also proposes to permit competitive bidding processes to be used as a basis for setting the energy and/or capacity components of avoided cost rates. The Coalition urges FERC not to abandon its existing precedents, which make clear that competitive solicitations can be used as one basis for avoided cost rate-setting, but cannot be used as the exclusive vehicle for offering QFs long-term energy and capacity contracts. As experience in the Northwest demonstrates, competitive bidding solicitations can include constraints that artificially limit competition, and the NOPR provides no evidence that these solicitations would encourage small power production and cogeneration QFs, as the statute still affirmatively requires.

V.

The NOPR proposes to relieve utilities in states with retail competition of the obligation to purchase power from QFs. This is flatly inconsistent with PURPA, which unequivocally requires utilities to purchase the entire output offered by QFs at avoided cost rates. If PURPA's must-purchase mandate is to be limited, that decision must come from Congress. The NOPR again oversteps FERC's authority by attempting to eliminate one of PURPA's core mandates in states with retail competition.

VI.

The NOPR proposes to alter the bright-line assurances provided by the Commission's current "one mile" rule – which ensures that generators separated by one mile will be considered separate facilities for purposes of PURPA's 80-MW size limitation – and replaces it with a wide-ranging set of balancing factors to be applied when generators are located within 10 miles. The proposal should be rejected because the NOPR fails to demonstrate that the current rule needs to be changed. Further, FERC's proposal to use balancing factors as opposed to a bright-line test, if adopted, will create unnecessary uncertainty and legal risk for projects attempting to qualify as QFs.

Worse, as written, the NOPR proposal may apply retroactively, which could expose projects built in reliance on the existing rules to the risk that their QF status would be unlawfully stripped away. Both long-standing FERC policy and well-established legal precedent require FERC to honor existing legal rights except in extraordinary circumstances. FERC does not even attempt to demonstrate that such extraordinary circumstances exist in this case.

VII.

Under current FERC rules enacted to implement Section 210(m) of PURPA, PURPA's must-purchase obligation continues to apply in the ISO/RTO "organized markets" for projects with 20 MW or less of capacity. The NOPR proposes to reduce this threshold to 1 MW.

The proposal should be rejected for several reasons. First, the NOPR provides no evidence to justify the change, and there is neither any reason to believe the 20 MW threshold has created problems nor any evidence that reducing the threshold to 1 MW would create any benefits. FERC's claim that, with various market reforms enacted since Section 210(m), small QFs now have unfettered access to competitive markets is belied by the evidence. Complex market rules and market customs favoring larger generators mean that small projects remain at a significant disadvantage. Many small projects under 20 MW are constructed and operated by non-traditional sellers whose primary businesses are irrigating farmland, operating sewage treatment facilities, harvesting timber, operating dairies, running cities, among other tasks, and they generally do not have the sophistication or financial ability to sell power, except for under PURPA. PURPA allows them to overcome many of these disadvantages but without PURPA's protections, small projects will lack the means to, for example, effectively negotiate contracts with utility incumbents and run the gauntlet of competing in competitive solicitations and organized markets. If anything, because trading in the electricity markets generally requires blocks of energy of at least 25 MW, the threshold under Section 210(m) should be raised to 25 MW, not reduced.

VIII.

The NOPR proposes to require QFs to have a commitment to financing in place before a legally enforceable obligation ("LEO"), entitling them to sell their output at avoided cost rates, can be created. This proposal must be rejected because it places QFs in a Catch 22 – financing depends on the existence of an enforceable obligation for the generator to sell its output but the proposed rule would make that enforceable obligation dependent on the existence of a commitment to financing. While the Coalition agrees that the LEO concept could benefit from greater clarity, the NOPR must be rejected because it raises the bar to creating a LEO so high that it becomes impossible to achieve.

IX.

FERC proposes to adopt the NOPR with no environmental analysis whatsoever. This is an obvious violation of the National Environmental Policy Act ("NEPA"). PURPA remains the only policy to promote renewable energy development in the 21 states that lack an RPS or other mandates encouraging renewable energy development; the NOPR therefore undercuts PURPA's primary mandate for promoting renewable energy which obviously has serious environmental impacts and creates impacts for critical ecosystems across the country. NEPA requires an agency to conduct a full analysis of such environmental impacts before it adopts any policy that may significantly affect environmental quality.

FERC claims that it need not conduct an environmental analysis because states remain the primary enforcers of PURPA and the outcome of the NOPR is therefore uncertain. This defies well-established NEPA precedent, which requires federal agencies to evaluate the environmental impacts of proposed policies even if the outcome of those policies is uncertain. In fact, FERC issued a full environmental impact statement when it first adopted PURPA rules in 1980 and it similarly issued a full environmental impact statement when it adopted Order No. 888, even though the environmental impacts depended on a number of uncertain factors, such as the price of coal and natural gas.

Before proceeding with the NOPR, FERC is therefore required to conduct a complete environmental analysis of the impacts of its proposals.

IDENTITY OF COMMENTERS

NIPPC is a Washington-based trade association. Organized as a nonprofit corporation, NIPPC's members include independent power producers who develop and operate power plants, as well as power marketers, and independent transmission companies. NIPPC's members have collectively invested billions of dollars in existing generation resources in the United States and also have renewable and thermal projects in advanced development in the Northwest.

CREA is an Oregon-based intergovernmental association, formed under Oregon Revised Statutes Sections 190.003 to 190.120. CREA consists of local governments, including several Oregon counties, working with CREA's member organizations, which include irrigation districts, businesses, individuals and non-profit organizations. CREA advocates for policies that will promote successful development and operation of renewable energy facilities in Oregon's rural counties, especially policies encouraging development of community-scale renewable energy facilities.[4]

REC is an unincorporated trade association that is comprised of nearly 40 members who own and operate nearly 50 qualifying facilities or are attempting to develop new QFs under PURPA in Oregon, Idaho, Washington, Utah, Montana and Wyoming. REC's members include irrigation districts, water and waste management districts, corporations, small utilities, and individuals with an interest in selling renewable energy to utilities – who, absent PURPA, may have no viable mechanism to develop and sell the output of renewable energy projects.

OSEIA is a trade association founded in 1981 to promote clean, renewable, solar technologies. OSEIA members include businesses, non-profit groups, and other solar industry stakeholders. OSEIA provides a unified and respected voice of the solar industry and focus

[4] Further information about CREA and REC is contained in the attached Declarations of Les Perkins and John Lowe.

exclusively on the solar value chain; from workforce development to permitting, advocacy, policy, and regulation for residential, commercial, community, and utility scale solar projects on the local, state and regional level.

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I. THE COMMISSION SHOULD NOT REFORM PURPA UNLESS AND UNTIL THERE IS ROBUST, NON-DISCRIMINATORY COMPETITION IN THE NORTHWEST.

A. Effective Wholesale Competition Best Promotes Consumer Welfare, Industry Innovation, and Industry Investment.

As the Commission has long recognized, PURPA introduced competition with traditional utility generation.[5] PURPA for the first time allowed independent power producers to access electricity markets that had previously been controlled by traditional utilities, and produced a wave of new investments in independently-owned generation and cogeneration facilities. PURPA was a major landmark in the evolution of the industry, setting the stage for the Commission's commitment to competition in the wholesale electricity markets.

Based in large part on the success of PURPA in promoting alternative sources of supply and new sources of competition in the wholesale electric market, the Commission has for a generation been committed to ensuring a level competitive playing field for suppliers in the wholesale electric markets. Effective competition has been the central organizing principle of Commission policy beginning with Order No. 69, and accelerating with its landmark Order No. 888, and each landmark order issued since that time, including Orders No. 889, 1000, 2000, and others. The Northwest Coalition strongly supports the Commission's pro-competitive policies and agrees with the Commission that genuine, effective competition in the wholesale electric markets is the best means for protecting consumers, promoting much-needed innovation in the industry, forcing necessary efficiencies, and laying the foundation for the huge investments that will be needed to assure that electricity prices remain reasonable while

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5 *E.g.*, Order No. 888, 61 Fed. Reg. 21,540, 21,545 (May 10, 1996) (noting the "rapid expansion and performance of the QF industry demonstrated that traditional, vertically integrated public utilities need not be the only sources of reliable power").

meeting huge challenges in, for example, cybersecurity, digitization of the grid, and climate policy. While the Northwest Coalition agrees that substantial progress has been made over the last four decades toward that goal of effective competition, for the reasons detailed in these comments, significant barriers to effective competition in the wholesale electric markets still exist. These barriers still hamper the ability of independent power producers to compete on a level playing field with utility incumbents.

For these reasons, PURPA remains an important tool for independent power producers in the Northwest, operating as QFs, to compete against the utility's marginal cost of generation. If adopted, the NOPR would significantly weaken PURPA, if not rendering it a dead letter entirely, and would therefore represent a reversal of the Commission's pro-competitive policies.

B. Effective Competition In The Wholesale Electric Markets Remains Elusive, Especially in the Northwest.

Effective wholesale competition, in which IPPs can compete on a level playing field with utility incumbents, remains elusive, especially in the Northwest. We base this conclusion on a number of observations about the state of the markets in this region.

First, there is no organized competitive wholesale market in the region. The major trading hub is the Mid-Columbia hub, which is merely a day-ahead, bilateral trading hub without any organized market structure designed to ensure non-discriminatory treatment by an independent market operator, consistent liquidity, or the other objectives of an ISO or RTO. There is no evidence cited in the NOPR that IPPs, especially smaller IPPs or QFs, could consistently obtain long-term energy sales through the Mid-Columbia hub. The region is now seeking to expand the EIM from its original footprint in the California ISO to other utilities in the Northwest. However, the EIM is only a five-minute market meant to optimize the dispatch of existing resources for purposes of covering regional requirements for moment-to-moment balancing reserves. There is nothing on the horizon to suggest that the Northwest will have either an organized day-ahead or an organized long-term market anytime in the foreseeable future. In the absence of such an organized market, the NOPR's conclusions about the state of competition in the ISO/RTO regions says nothing about the state of competition in the Northwest. Thus, many of the assumptions in the NOPR are simply inapplicable to the Northwest.

The competition in the wholesale generation market – assumed to exist in the NOPR as an adequate substitute for the PURPA's must-purchase obligation – is limited to the utility-run competitive solicitations that occur in the region. However, significant challenges remain to ensure solicitation processes are truly competitive in a way that could allow replacement of PURPA's must-purchase obligation. Generally, the applicable state utility commission may oversee the RFP processes in the Northwest states. However, in Northwest procurements, the utility itself runs the process and evaluates the bids, including bids that would result in the winning resource being added to the utility's rate base, either through a direct utility self build, a build-own transfer, or a PPA with a utility right to purchase the facility. State rules may require the utility to hire an independent evaluator, but the utility still designs the RFP, runs the RFP, and makes the final resource selection. Among many other challenges with this arrangement, these RFPs allow utility-ownership bids to be submitted on a cost-of-service basis where the utility will be authorized under state law to recover all prudently incurred costs and return on rate base once the facility is approved for rates.[6] In contrast, an IPP bid to sell under a PPA will be limited to a fixed-price PPA and must necessarily build additional risk

6 *See, e.g.,* Ore. Rev. Stat. 756.040; *Gearhart v. Pub. Util. Comm'n of Or.,* 356 Or. 216, 220, 339 P.3d 904 (2014) (describing cost-of-service rate recovery for Oregon's electric utilities).

contingencies into its RFP bid price. The merchant arms of incumbent utilities have historically prevailed in most of these solicitations,[7] a result that would be almost impossible in a truly competitive market.

Additionally, contrary to the NOPR's apparent assumption, it is not clear that state laws typically provide the authority to ensure a truly competitive solicitation process. State commissions have generally found that state law limits their ability to interfere in the judgment of the incumbent utility with respect to final resource acquisitions in such solicitations, even where the utility is found to have not followed the state's bidding rules.[8] State law may also place limits on the state commission's ability to disallow rate recovery when the utility prevails in its own bid and ratepayers or other stakeholders complain that the solicitation was unfair.[9] The states also have an inherent jurisdictional limitation that limits their ability to prevent anti-competitive practices in interstate transmission and wholesale power markets, areas which are, of course, subject to exclusive FERC jurisdiction, but can arise in RFPs.

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[7] *See* J. Migden-Ostrander, "Decoupling and Integrated Resource Planning," *The Regulatory Assistance Project* (March 16, 2018) at p. 55, available at: https://www.raponline.org/wp-content/uploads/2018/03/rap_migden_mt_senate_decoupling_irp_2018_mar_16.pdf (noting that Oregon has been held up as a state with strong planning and bidding rules, but "Oregon has been criticized for its competitive procurement process, in which the utility has won the bid 95% of the time").

[8] *See* Ore. Admin. R. 860-089-010 - .0550 (only acknowledging the final shortlist of the RFP and not approving the final resource selection). For example, in an RFP commenced in 2017 for acquisition of wind facilities in Wyoming, the Oregon PUC found that PacifiCorp had not faithfully run a fair RFP and therefore declined to "acknowledge" the final short list of bids. *In re PacifiCorp, dba Pacific Power, 2017R Request for Proposals*, Ore. PUC Docket No. UM 1845, Order No. 18-178, at 10-11 (May 23, 2018) (stating "We share the frustration of the IE and the participants that the bid selection process ended up being limited to selection of only those projects with favorable queue positions, which includes projects for which PacifiCorp had acquired the development rights as benchmark projects."). But PacifiCorp still undertook acquisition of this 1,300-MW resource addition, all but 200 MW of which would be PacifiCorp owned. Pete Danko, "PacifiCorp says $3.5B renewable plan a go despite regulator misgivings about bidding process." *Portland Business Journal* (May 22, 2018), available at: https://www.bizjournals.com/portland/news/2018/05/22/pacificorp-says-3-5b-renewable-plan-a-go-despite.html.

[9] For example, Oregon law allows the utility to recover all prudently incurred capital investments and operating costs. Ore. Rev. Stat. 756.040.

The available evidence includes instances where incumbent utilities in the Northwest have developed generation facilities that have been costlier and riskier to customers than what would have occurred if a level competitive playing field had existed.[10] This includes projects that were more expensive than comparable IPP resources,[11] underperformed,[12] or were never placed in service and abandoned.[13] As this evidence shows, utility-owned assets carry the inherent risk of utility ownership, where ratepayers may fund their cost overruns or underperformance.[14]

Barriers to competition are also evident outside the context of competitive solicitation processes. For example, PacifiCorp recently stopped processing applications for interconnection service in its BAAs, claiming that its power flow software cannot identify transmission constraints when existing and planned generation within its BAA exceeds the load within its BAA. But PacifiCorp's posture is directly contrary to the Commission's open access transmission orders and market-oriented competitive regulation, both of which assume the free flow of power between BAAs.[15] PacifiCorp's refusal to process transmission applications is particularly problematic for the West because PacifiCorp's BAAs contain many of the best

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[10] For a more detailed description of such instances and a detailed discussion of the challenges presented by RFPs, *see Northwest and Intermountain Power Producers Coalition's Comments*, Wash. UTC Docket No. UE-161024, at pp. 9-15 (filed Nov. 2, 2016), available at https://www.utc.wa.gov/docs/Pages/DocketLookup.aspx.

[11] *See id.* at 11-13 (comparing Puget Sound Energy's acquisition of the utility-owned Lower Snake River 1 wind farm at a cost of $70.62 per MWh with a contemporaneous PPA for an IPP wind farm in the same state by Avista at a fixed price of only $62 per MWh).

[12] *See id.* at 13 (explaining that PacifiCorp systemically over-estimated the capacity factor of 12 wind plants that began operating prior to 2010).

[13] *See id.* at 13 (discussing Avista's recovery in customers rates of sunk development costs on its abandoned Reardan Wind Farm project).

[14] *See id.* at 14 (discussing PacifiCorp's outage at its Hunter plant in 2000 ended up costing Oregon customers more than $130 million in power costs, plus paying for the utility's legal and other fees to litigate the case all the way to the Oregon Court of Appeals).

[15] *See Comments of NIPPC*, FERC Docket No. ER19-1948-000, PacifiCorp Order 845 Compliance Filings (filed June 26, 2019).

power resources (including both traditional fossil fuel resources and renewable resources such as wind and solar), so the inability to transmit power from these areas across PacifiCorp's BAA boundaries to the West's large population centers undermines not only wholesale market competition but the ability of many Western states to meet their aggressive mandates for renewable energy generation at the lowest possible cost to consumers.

Additionally, the NOPR overlooks significant barriers to competition that exist for certain QFs regardless of the market structure. First, there is no basis to conclude that an RFP might be won by an owner or developer of a smaller QF. No party has cited an example where a small renewable energy facility or cogeneration facility, e.g. 10 MW or smaller, has prevailed in a typical RFP for a major resource acquisition that allows bids for major generation facilities. In Oregon, for example, the competitive bidding rules of the Oregon PUC are only required when the utility seeks an acquisition of at least 80 MW in size,[16] and therefore the small hydropower or cogeneration developer, or owner of an existing facility simply trying to renew an expiring PURPA PPA to remain in existence, would be competing against much larger projects. In fact, RFPs issued by Northwest utilities routinely preclude smaller projects from bidding.[17] The assumption that any small QF could compete, much less prevail, in a typical RFP overlooks the basic economics of a small QF project; the transaction costs to compete in the RFP are largely fixed, whether the proposed facility is 1 MW or 300 MW. Obviously, the developer of the much smaller scale facility will be at a disadvantage in competing against the utility's own rate-base RFP proposal and developers of much larger facilities with greater economies of scale.

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16 Ore. Admin. R. 860-089-0100(1)(a).

17 These facts are discussed in further detail in the attached Declaration of Carol Loughlin, which provides several examples of such restrictions in recent RFPs.

These problems are even more acute for QF developers and owners whose primary business enterprise is not the generation of electric energy and participation in marketing such energy. For example, many of the QFs in the Northwest are small hydropower facilities – both existing facilities and facilities that are under development to take advantage of other Congressional directives to promote such resources. These facilities are often developed, owned, and/or operated by governmental entities or local irrigation districts. To assume, for example, that the developer of a 2-MW in-conduit hydropower facility attempting to use recently enacted laws promoting such development, such as the Hydropower Efficiency Act of 2013,[18] could somehow engage in and win a utility RFP for its next major resource is implausible. Like many cogeneration units, many of these smaller QFs' developers and owners are primarily engaged in other business enterprises, such as distributing irrigation water, and are not sophisticated market participants in the energy markets. The same would true of small solar QFs that may be sited at commercial or industrial facility. The Northwest Coalition is concurrently submitting the Declarations of John Lowe and Les Perkins to further demonstrate the circumstances of small QFs operated by irrigation districts and other small QFs.

In light of these persistent barriers to competition that exist for cogeneration and small power production facilities, the Northwest Coalition believes PURPA remains an essential tool to encourage competition by allowing QFs to attempt to compete against the utility's marginal cost of generation. However, the proposals contained in the NOPR almost universally undercut PURPA and therefore constitute a significant step backwards from the Commission's ideals of competitive wholesale power markets.

[18] Pub. L. 113-23 (2013).

C. PURPA Requirements Should Be Eased Only After Effective Competition Emerges, But the NOPR Overlooks that Effective Competition Does Not Yet Exist in all Markets.

As the evidence discussed above demonstrates, the Commission's view of the state of industry competition cannot be squared with reality, especially in the Northwest. A careful review of the specific facts cited by the Commission demonstrates that the conclusion that effective competition has arrived is unjustified. The Commission cites the "fracking revolution" in the natural gas industry, incentives for development of renewable resources, and the introduction of competition as the three basic justifications for its conclusion that PURPA is an anachronism.[19] None of these developments support the Commission's keystone conclusion that competition now allows QFs access to electricity markets on a level competitive playing field.

The Commission's conclusion that the increased availability of inexpensive domestic natural gas produced by new fracking technologies levels the competitive playing field in the wholesale electricity markets[20] is a *non sequitur.* While the increased supply of natural gas is certainly one of the more remarkable developments in the energy industry in the last four decades, and there is little doubt that this has allowed gas-fired electric generation to replace more expensive generation in many cases, the drop in price for one input for one type of electric generation does nothing to remove the barriers to competition that continue to exist within the wholesale electricity markets. As the Commission acknowledges,[21] Orders No. 69 and 70 were aimed at overcoming the traditional reluctance of incumbent utilities to purchase from competing suppliers and the increased availability of natural gas is wholly unrelated to

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19 NOPR at PP 19-27.

20 NOPR at P 19 & nn. 23-25.

21 NOPR at P 17.

that problem. These are the same problems targeted by Congress when it enacted PURPA, as the U.S. Supreme Court confirmed in *FERC v. Mississippi*.[22] Moreover, if the reasons Congress enacted PURPA no longer exist, it is for Congress, not FERC, to repeal the statutory requirements.

The Commission's assertion that the maturation of the renewable energy industry over the last forty years justifies a headlong retreat from PURPA[23] also fails to withstand scrutiny. There is little doubt that the massive drop in the price of renewable technologies, especially solar and wind, and state and federal policies favoring renewable resources, have produced a significant increase in demand for renewable generation, especially in the last decade. But these policies are not all permanent. As the Commission recognizes, the federal tax credits for renewable generation are now being phased out.[24]

In any event, for purposes of the NOPR, the real question is whether growth in renewables is as great as it would have been if effective competition in the wholesale electricity markets existed, or if the growth would have occurred absent PURPA. Contrary to the NOPR's conclusions, PURPA programs in some Northwest states, such as Idaho, have led to significant growth of independently owned renewable generation. In the case of Idaho Power, over 1,119 MW of PURPA QFs are now online from 127 individual small hydro, cogeneration,

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22 456 U.S. 742 (1982). As the Supreme Court noted, while Congress believed that encouraging QFs would help the nation reduce its dependence on fossil fuels, Section 210 was aimed primarily at two problems that "impeded the development of nontraditional generating facilities: (1) traditional electricity utilities were reluctant to purchase power from, and to sell power to, the nontraditional facilities, and (2) the regulation of these alternative energy sources by state and federal utility authorities imposed financial burdens upon the nontraditional facilities and thus discouraged their development." 456 U.S. at 750-51. Hence, increased natural gas supplies by itself does not solve the problems Congress intended Section 210 to address.

23 NOPR at PP 20-23.

24 NOPR n. 26.

biomass, wind, and solar QFs, which serve 19.3 percent of Idaho Power's load.[25] PURPA remains a critical avenue for renewable development in the West, and the reforms proposed by the Commission are likely to seriously undermine the continued growth of renewable resources.

The figures cited in the NOPR concerning the increased deployment of renewable resources[26] do not support the conclusion that effective competition now characterizes the wholesale electric markets. While there is no doubt that the levelized cost of renewables has declined dramatically in recent years, and that renewables can now be delivered at a cost comparable with or below the costs of traditional resources in much of the country, by itself this does not demonstrate effective competition. On the contrary, given these price trends and the policies favoring renewables noted by the question, it is reasonable to expect that deployment of renewables would be considerably greater if independent renewable producers did not face persistent barriers to electric market competition.

The key figures cited by the Commission do not shed any light on this question. For example, the Commission asserts that renewables, including hydroelectric power, currently represent approximately 20 percent of net electricity generated in the United States and 22 percent of installed capacity.[27] But this does not answer the question whether the market penetration of renewables would be greater in the absence of the persistent barriers to effective competition we have documented. Indeed, given the price and policy trends noted by the Commission, it would be reasonable to expect that market penetration would be considerably higher. In any event, the figures cited by the Commission include hydroelectric power, the

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25 *See* Idaho Power's 2019 Integrated Resource Plan, at pp. 22, 31, available at: https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2019/2019_IRP.pdf.

26 NOPR at PP 20-23 & nn. 28-34.

27 NOPR at P 21 & nn. 31-32.

vast majority of which was constructed decades ago, so the figures say little about net additions of renewable capacity in recent years.

The NOPR also asserts that almost 100 percent of renewable resources in 1995 were QFs, while QFs have made up only 10 to 20 percent of new renewable capacity since 2005, and that this demonstrates that renewables are being built "through wholesale market constructs that have developed since the Commission first implemented PURPA."[28] This is another *non sequitur.* The figures cited by the Commission do not distinguish between new renewable capacity being added by incumbent utilities and that being constructed by IPPs relying on access to the wholesale markets on terms equal to the incumbent utilities. Unless the Commission can identify how much renewable capacity is being added by utility incumbents to, for example, comply with state-level RPS requirements, and how much is being constructed by the competitors of incumbent utilities, the Commission can draw no valid conclusions about the state of competition between traditional utilities and IPPs.

In fact, the vast majority of new non-QF renewable generation in the Northwest is owned directly by the incumbent investor-owned utilities.[29] Only a handful of projects have been constructed under a competitive bidding process in which an independent power producer won the right to construct the generation. Likewise, the same EIA data relied upon by the NOPR indicates the vast majority of all electric energy generated in the Northwest states is

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[28] NOPR at P 22 & n. 33. This data appears to omit PURPA's relevance to small hydropower facilities because clearly 100 percent of hydropower in the country was not selling under PURPA in 1995. By omitting PURPA's relevance to small hydropower, the NOPR overlooks PURPA's importance to that renewable resource.

[29] These facts are discussed in more detail in the attached Declaration of Carol Loughlin, which includes a detailed table, in its Attachment A, identifying the ownership structure resulting from major non-QF wind and solar utility acquisitions in the last 15 years.

generated by utility-owned plants, not IPPs, whether considering all fuel types or just wind and solar.[30]

Similarly, while the Commission has, through Order No. 888 and related pro-competitive initiatives such as RTOs and ISOs, made significant progress toward the goal of fully competitive wholesale electric markets,[31] the Commission's project remains incomplete. While the Northwest Coalition strongly supports the Commission's pro-competition agenda, as the examples set forth in the previous section demonstrate, the ideal of competition on a level playing field has yet to arrive.

The Commission also fails to recognize that much of the existing renewable energy resources built prior to 1995 may need PURPA in its current form to be able to continue to sell power after the expiration of their current contracts. In the Rocky Mountain and Pacific Northwest regions, the Northwest Coalition estimates from available data that there are approximately 300 individual QFs with capacity of 20 MW or less selling power to PacifiCorp, Idaho Power Company, Portland General Electric Company, Puget Sound Energy, and Avista.[32] The majority of these projects are small-scale hydroelectric facilities and are between the sizes of 1 MW and 20 MW, and would be directly impacted by FERC's NOPR.[33] The vast

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30 *See id.* at Attachment B (containing tables of data). The only outlier state is Montana, which is likely due to its period of deregulation before more recently returning to a vertically integrated utility model.

31 *See* NOPR at PP 25-27.

32 For 20 MWs and smaller, approximately 115 operating projects with over 400 MW of capacity are selling power to PacifiCorp (about a third of which are small hydro QFs 6 MW and less), and 127 operating projects with about 1,119 MW capacity are selling to Idaho Power (about 90 of which are small hydro 10 MW and lower). *See Post Technical Conference Comments of the Community Renewable Energy Assoc.*, FERC Docket No. AD16-16, at Attachment 1 (filed Nov. 7, 2016) (containing a recent list of QFs selling to PacifiCorp); Idaho Power's 2019 Integrated Resource Plan, at pp. 22, 31, available at: https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2019/2019_IRP.pdf.

33 The majority, which is over 150 of PacifiCorp's and Idaho Power Project's combined PURPA projects, are between the sizes of 1 MW and 20 MWs.

majority of these projects are also located in rural parts of the Western United States and provide important sources of revenue for these communities. These projects are often local companies (farmers, dairies, etc.) or governmental units (irrigation districts, cities, counties, etc.), which re-invest their much needed revenues in economically disadvantaged communities.[34]

The NOPR does not recognize the manner in which many operating small renewable energy projects sell power in the Northwest.[35] Smaller projects often lack sophistication, cannot overcome high transaction costs, do not have economies of scale, and are unable to economically access alternative markets. Small QFs do not typically have in-house attorneys and experts with the skills to assist in the evaluation and negotiation of contracts, and often need to hire outside experts. In addition, even under PURPA, negotiating a QF contract with a utility can take a great deal of time. This makes completion of such agreements quite challenging and risky since many factors important to the negotiation can change during an extended process. All of these transactional costs can impose significant economic burdens and risks and can make a smaller project uneconomic.

Existing and operating projects face unique challenges, which are ignored in the NOPR and its focus on the evolution of markets in areas other than the Northwest. Similar to new projects, existing projects often need to enter into long-term contracts when their current contract expires. However, unlike new projects that can sometimes wait to deploy their capital

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[34] *See, e.g.*, Natural Resources Defense Council, R-18-10-A, *Clean Energy Sweeps Across Rural America* (Nov. 2018) (available at: https://www.nrdc.org/sites/default/files/rural-clean-energy-report.pdf); R. Ferroukhi *et al.*, International Renewable Energy Agency, *Renewable Energy Benefits Measuring the Economics* (2016) (available at: https://www.irena.org/documentdownloads/publications/irena_measuring-the-economics_2016.pdf).

[35] The attached Declarations of John Lowe and Les Perkins demonstrates these points regarding the limitations on many small QFs operating existing facilities.

when prices are higher, existing projects have no flexibility when their new contract starts and almost always start with an initial period of low prices. Unlike some new developers that can site their projects in states or regions with favorable renewable policies or prices, existing projects cannot change their location, and generally their only option is to shut down or continue to sell power to their interconnected utility. The Commission should reconsider the purposes of the NOPR in light of these realities for existing QFs.

In sum, therefore, rather than backsliding on PURPA before effective wholesale competition is demonstrated, FERC should ensure that there is, in fact, effective competition before undertaking any major reforms of the must-buy provisions.

II. RESPONSE TO THE NOPR'S PROPOSED REVISIONS TO PURPA

A. The NOPR Violates PURPA's Statutory Requirements That The Commission's Rules "Encourage" QF Development and Protect QFs Against Discrimination.

In addition to retreating from the Commission's pro-competition policies, the proposed rule would violate the PURPA's statutory requirements. As the Supreme Court has explained, "'Congress believed that increased use of these [cogeneration and small power production] sources of energy would reduce the demand for traditional fossil fuels,' and it recognized that electric utilities had traditionally been 'reluctant to purchase power from, and to sell power to, the nontraditional facilities.'"[36] Thus, Section 210(a) of PURPA requires that the Commission maintain "such rules as it determines necessary to *encourage* cogeneration and small power production[.]"[37] Similarly, given the recognized reluctance of utilities to purchase power from their competitors, Section 210(b) of PURPA affirmatively commands that "rules prescribed

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[36] *Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 405, 103 S. Ct. 1921, 1924 (1983) (quoting *FERC v. Mississippi*, 456 U.S. 742, 750 (1982)).

[37] 16 U.S.C. § 824a-3(a) (emph. added).

under subsection (a) shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase— (1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and (2) *shall not discriminate against qualifying cogenerators or qualifying small power producers*."[38]

The legislative history confirms that Congress intended for QFs to be encouraged under the statute. The Conference Report states: "The conferees wish to make clear that cogeneration is to be encouraged under this section . . . ."[39] Congress specifically recognized that "cogenerators and small power producers are different from electric utilities, not being guaranteed a rate of return on their activities generally or on the activities vis a vis the sale of power to the utility and whose risk in proceeding forward in the cogeneration or small power production enterprise is not guaranteed to be recoverable."[40] In light of the fact that QFs may not recover their actual costs plus a pre-authorized return like traditional utilities, Congress also recognized that attempts to set the rates based on the avoided costs at the time of delivery would likely be insufficient to encourage such facilities. Instead, "the Commission and States should look to the reliability of that power to the utility and the cost savings to the utility which may result at some later date by reason of supply to the utility at that time of power from the cogenerator or small power producer."[41]

The existing must-purchase rules faithfully implemented these directives with the requirements that utilities purchase all energy and capacity offered by QFs and that such purchases be made, at the election of the QF, at fixed-price rates for energy and capacity

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38 16 U.S.C. § 824a-3(b) (emph. added).
39 H. R. Conf. Rep. No. 95-1750, pp. 97-98 (1978).
40 *Id.*
41 *Id.*

calculated at the time of the legally enforceable obligation. The existing rules – especially long-term fixed prices for energy and capacity – were found to be necessary to encourage investment in QFs, and that finding has proved to be correct over time.

In contrast, the NOPR proposes to completely gut these requirements without any explanation or record supporting a conclusion the rules will continue to encourage QFs. Furthermore, the NOPR fails to even acknowledge the additional statutory requirement that the rates offered to QFs must be non-discriminatory. The reasoning of the NOPR relies on an assertion that it is no longer necessary to encourage QFs due to available competitive wholesale markets and state-level renewable energy mandates, but that reasoning overlooks the fact that the statute still states the Commission must encourage QFs.

The scope of changes proposed rises to the level of amendments to the statute's substantive requirements that must be made by Congress itself. As Chairman Neil Chatterjee testified before Congress, "I will say that any major changes to PURPA would be made by Congress. And while you have my assurance I will work very seriously on these issues, should I be confirmed, I think any major changes need to come from this body and not FERC."[42] Similarly, then-Chairman Kevin McIntyre explained that "any significant overhaul of PURPA would have to come from Congress" before going on to suggest the Commission may consider less significant revisions, such as revisions to the one-mile rule.[43]

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[42] *The Nominations of the Honorable Dan R. Brouillette to be Deputy Secretary of Energy and Neil Chatterjee and Honorable Robert F. Powelson to Members of the Federal Energy Regulatory Commission: Hearing Before the Committee on Energy and Natural Resources United States Senate,* 115th Congress, S. Hrg. 115-256, at p. 51 (May 25, 2017).

[43] *Oversight of the Federal Energy Regulatory Commission and the FY 2019 Budget: Hearing Before the Subcommittee on Energy and Commerce House of Representatives*, 115th Congress, at p. 95 (April 17, 2018).

Therefore, as the Commissioners recognized before Congress, while it may be appropriate to implement some limited changes to the rules, the major proposals are not lawful. The Commission cannot take it upon itself to change the underlying policy directives to encourage QFs and ensure non-discriminatory rates out of frustration with Congress's decision not to take action.[44] If PURPA is indeed an anachronism, it is up to Congress, not the Commission, to repeal the law. As the adoption of PURPA Section 210(m) in 2005 demonstrates, Congress is well aware of the changes that have occurred in the electric utility industry over the last half-century and has adapted PURPA's must-purchase obligations to fit those changes. If additional changes are needed to reflect additional competition-related reforms that have occurred since 2005, it is up to Congress to make those changes to PURPA's core mandates. The Commission oversteps its authority by proposing changes that effectively write PURPA Section 210 out of existence.

B. The NOPR's Proposal to Eliminate the Requirement for Fixed Energy Prices Should Not be Adopted

The Northwest Coalition strongly opposes the NOPR's proposal to eliminate the requirement that states offer QFs a fixed energy price as part of the forecasted avoided costs required by Section 292.304(d) of the Commission's regulations.[45] This proposal would undercut the bedrock right to obtain long-term fixed-price contracts that support the investment in cogeneration and small power production facilities, without any record evidence demonstrating how the regulations would continue to encourage QFs in a non-discriminatory manner.

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[44] *See Office of Consumer Counsel v. FERC*, 655 F.2d 1132, 1151-53 (D.C. Cir. 1980) (vacating regulations where the court found FERC exceeded statutory authority and acted out of frustration with lack of congressional action).

[45] NOPR at PP 61-81.

1. The NOPR Incorrectly Assumes Fixed-Price Avoided Costs Will Exceed Actual Avoided Costs

The NOPR relies on an assumption that Order No. 69 may have been incorrect to assume that over time overestimations and underestimations of forecasted avoided cost rates would "balance out."[46] But the cited evidence does not support the drastic change to the Commission's regulations proposed by the NOPR. On the contrary, the NOPR relies on flawed data and analysis for its assumption that avoided cost estimates have been too high.

The NOPR asserts that market prices have fallen in recent years and therefore any new long-term PURPA resource is likely to contain avoided cost rates that will turn out to be overestimates of the avoided costs calculated at the time of delivery.[47] But this argument answers the wrong question. Under an avoided cost inquiry, the question is what the utilities would have paid for the energy and capacity supplied by the QFs if the QFs had not been built and sold their output to the utility. Instead, the NOPR's reasoning looks at the actual market prices that resulted after substantial amounts of QF generation were added to the grid, thus depressing market prices. As noted above, small hydro, cogeneration, biomass, wind, and solar QFs, serve 19.3 percent of Idaho Power's load.[48] New resources of this magnitude of course drive down power prices. But it makes no sense to ignore these market effects, which generally create significant benefits for electric consumers.

Further, forward price curves and other methods of projected long-term avoided costs are likely to include information that is foreseeable at the time those prices are developed, and therefore will reflect factors like anticipated demand growth and the costs of new generation

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46 NOPR at PP 39-40, 68 (quoting Order No. 69, 45 Fed. Reg. 12,214, 12,224 Feb. 25, 1980).

47 *Id.*

48 *See* Idaho Power's 2019 Integrated Resource Plan, at pp. 22, 31, available at: https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2019/2019_IRP.pdf.

technology. But the markets cannot anticipate some developments. For example, over the last twenty years, major technological advances like new natural gas extraction techniques and dramatic declines in the costs of producing solar and wind generators were not generally anticipated. Similarly, very few analysts anticipated the most significant factor driving down electricity demand in the last decade, the severe recession of 2008-09. But that holds true for both QF contracts and rate-based utility generation. Therefore, the NOPR errs in claiming that generally declining energy prices have purportedly rendered QF contracts uneconomical without examining whether rate-based utility generation constructed at the same time as those QF contracts has also been rendered uneconomical according to the same metrics.

The real question, then, is how the cost of QF contracts compares with the costs of long-term generation constructed by utilities under the same market conditions. As we now demonstrate, the evidence is clear that QF contracts generally compare very favorably with rate-based utility generation when compared on an apples-to-apples basis.

The NOPR relies heavily on testimony of Commissioner Kristine Raper of the Idaho Public Utilities Commission ("Idaho PUC") and Edison Electric Institute ("EEI") comments that suggest QFs' long-term, fixed avoided cost payments have proven to be chronically above the actual avoided costs of the purchasing utility at the time of delivery.[49] But neither of these sources compares the costs of the QF contracts at issue to the alternative generation sources actually used by the utility to serve load in a reasonable manner.

The comparison made by Idaho Commissioner Raper asserts that the all-in energy and capacity prices paid to PURPA QFs by Idaho Power has exceeded the Mid-C index price,

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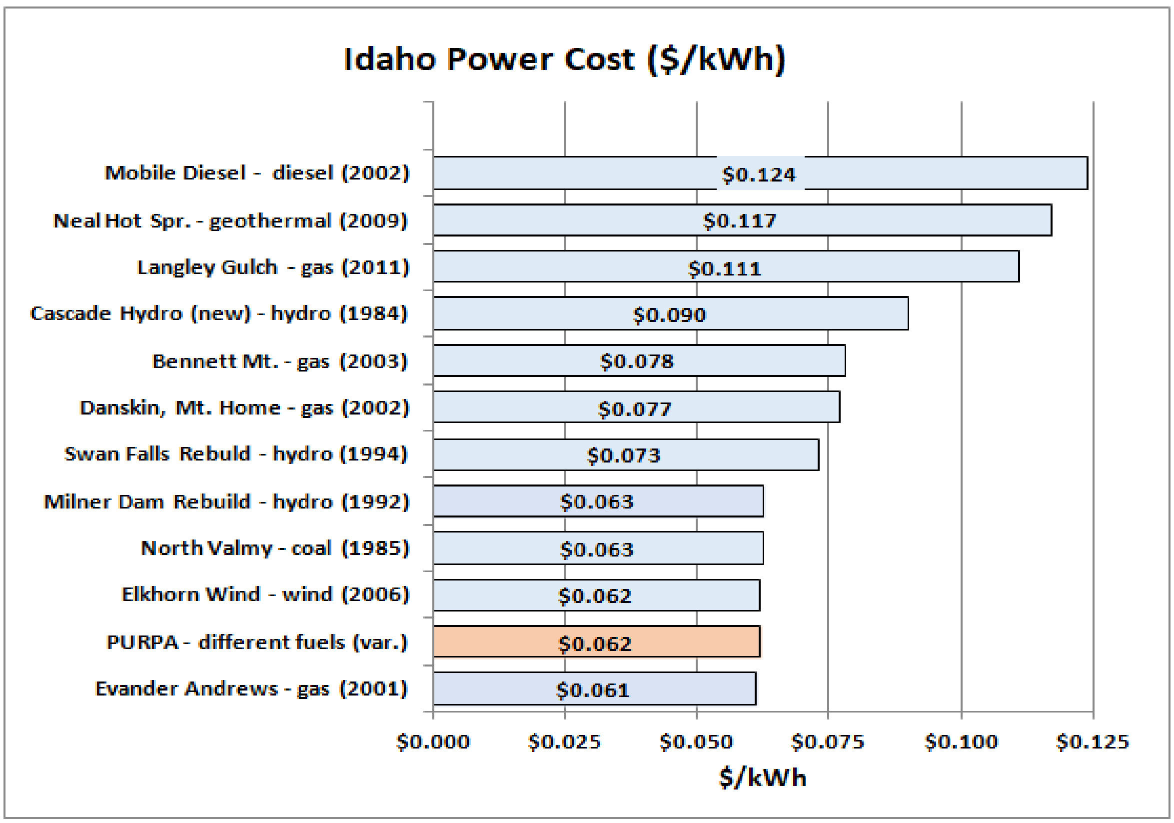
49 NOPR at P 64 & n. 101; *id.* at P 68.

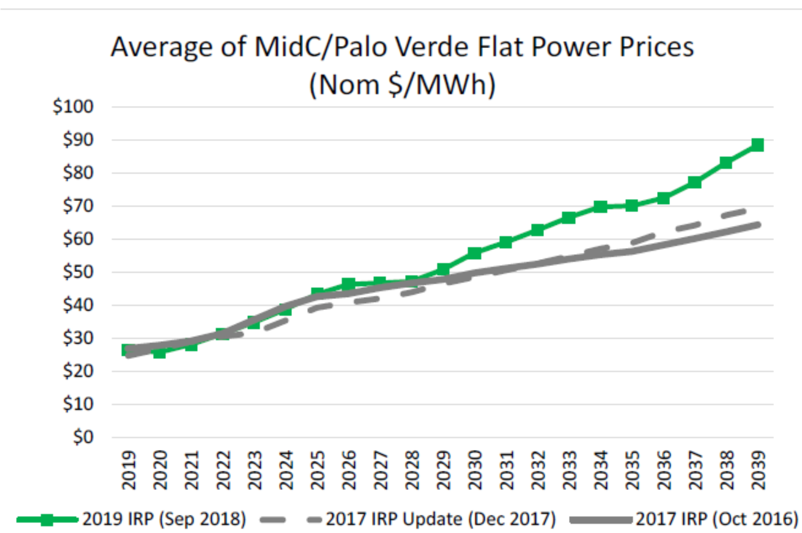
which is a day-ahead spot market price for energy.[50] This is an obviously flawed comparison. To supplement the record on this issue, the Northwest Coalition is submitting the expert report of Dr. Don C. Reading, a qualified economist with decades of experience testifying before the Idaho PUC, which explains that the referenced Mid-C index prices are not comparable to a long-term energy and capacity supply from Idaho Power's QF contracts. Dr. Reading's report contains a chart that shows the all-in costs approved by the Idaho PUC for Idaho Power's non-QF generation plants to the average annual costs actually paid to QFs under such long-term contracts in a recent year, and demonstrates that the costs of the PURPA facilities are lower than the approved costs for all but one of those non-QF plants.



50 NOPR at P 64 n. 101 (citing Technical Conference Testimony of Commissioner Kristine Raper, asserting that "Idaho Power demonstrated that the average cost for PURPA power since 2001 has exceed the Mid-Columbia (Mid-C) Index Price and is projected to continue to exceed the Mid-C price through 2032").

Additionally, as Dr. Reading explains in his report, the Idaho PUC deemed it imprudent for Idaho Power to rely on the short-term energy market to serve its load due to the historic volatility of that market, and therefore comparisons of short-term market prices to long-term PURPA contracts are not relevant.

Further, the NOPR assumes that generally declining prices are now a permanent feature of the electricity landscape. But that is not a reasonable expectation, at least in the Northwest. In fact, the current IRPs for each of the Northwest's IOUs predict significantly increased electricity demand and increasing market prices at the same time those utilities are facing retirements of much or all of their coal fleets. For example, PacifiCorp's most recent IRP predicts that prices will rise substantially over the next two decades, as demonstrated by this chart from that IRP:[51]



Similarly, the Portland General Electric IRP predicts significant increases in the West's wholesale electric prices between now and mid-century, observing that coal retirements, clean

51 PacifiCorp's 2019 Integrated Resource Plan, Volume I, Figure 8.37 (October 18, 2019), available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf.

energy mandates, and other sources of uncertainty have "yielded increasing forward trading curves, challenging the notion that the availability of low-priced gas and electricity can be expected to continue well into the future in the West." [52]

An examination of the underlying market fundamentals explains why the region's IOUs universally believe electricity prices will climb significantly. To start with, the region anticipates a substantial contraction of its coal fleet in the next decade. Coal generation comprised approximately 17 percent of Western utilities' reported capacity in 2016. The 34,000-MW aggregate generating capability of the Western coal fleet is expected to drop by more than half by 2030.[53] Economics for PacifiCorp's coal-fired generation have become so adverse it anticipates that 16 of its 24 coal plants will be retired by 2030, with four more retired by 2038.[54] This, of course, leaves the region with a significant capacity deficit to fill.

Examining the capacity deficit in light of recently-adopted legislation in the West Coast states requiring a 100% renewable or non-emitting generation fleet by mid-century, two recent studies have concluded that the price of capacity resources is likely to rise over the coming decades, especially as these states seek to eliminate the last increment of GHG-emitting resources from their generation portfolios.[55] Similarly, new developments such as electrification of the transportation fleet, which is also strongly supported by recently-adopted

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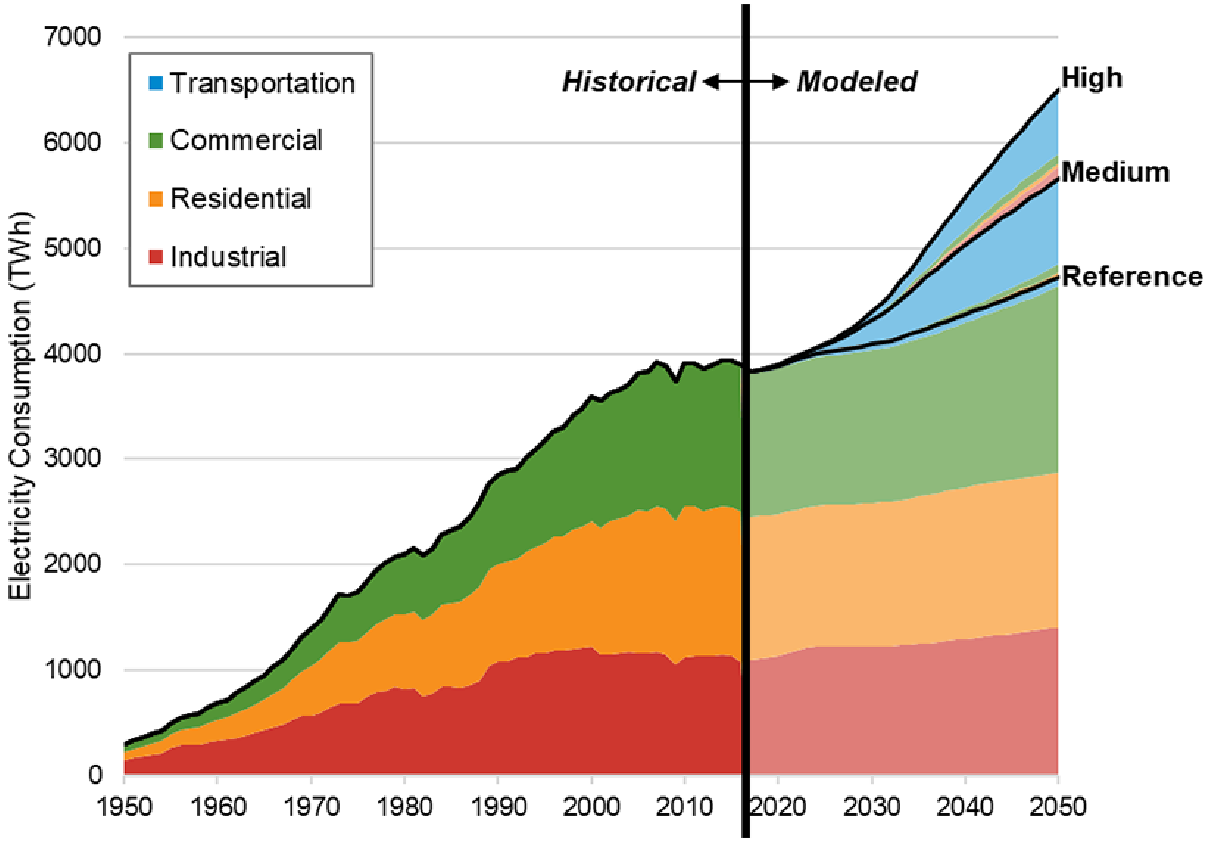
[52] Portland General Electric's 2019 Integrated Resource Plan, at 64 (July 2019), available at: https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning ; *see also id.* at 80-81 & Fig. 3-7, at 356 Fig. I-9 (showing strong upward trend in wholesale prices).

[53] Ben Kujala, "A Pile of Retirements: The Next 10 Years for Western Coal Plants," *Northwest Power and Conservation Council* (Aug. 19, 2019), available at: https://www.nwcouncil.org/news/coal-retirements.

[54] PacifiCorp's 2019 IRP, *supra* n. 51, at 12-13.

[55] Energy+Environmental Economics, "Resource Adequacy in the Pacific Northwest," (March 2019), available at: https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf); R. Hardy & L. Kitchen, "Future Northwest Capacity Shortages" (revised ed. May 1, 2019), available at: https://oregonpuc.granicus.com/MetaViewer.php?view_id=1&clip_id=406&meta_id=20877.

legislation in the West Coast states,[56] could substantially increase electricity demand, as this chart from the National Renewable Energy Laboratory Demonstrates:[57]



In a market with increasing demand and increasing prices, fixed-price QF contracts protect consumers against those rising prices as well as market volatility and market risk, and the project risk of utility-owned resource acquisitions by the Northwest's utilities.

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56 *See* Chapter 287, *Washington Session Laws 2019*, available at: http://leg.wa.gov/CodeReviser/documents/sessionlaw/2019pam2.pdf ; Oregon Enrolled SB 1044, signed July 15, 2019, available at: https://olis.leg.state.or.us/liz/2019R1/Downloads/MeasureDocument/SB1044/Enrolled .

57 "Electrification Futures Study: Scenarios of Electric Technology Adoption and Electricity Consumption in the United States" *National Renewable Energy Lab* (July 9, 2018), available at: https://www.nrel.gov/news/program/2018/analysis-demand-side-electrification-futures.html; *see also, e.g.,* F.T. Davidson *et al*., "Is America's Power Grid Ready for Electric Cars?" *CityLab* (Dec. 7, 2018), available at: https://www.citylab.com/transportation/2018/12/americas-power-grid-isnt-ready-electric-cars/577507/; "Global EV Outlook 2019: Scaling Up The Transition to Electric Mobility*," International Energy Agency* (May 27, 2019), available at: https://www.iea.org/publications/reports/globalevoutlook2019/.

In short, the NOPR is based on the theory that the general downward trend in electricity prices will continue indefinitely, and that this will render QF contracts uneconomical. Neither proposition is supported by the evidence. In the Northwest, available evidence suggests that electricity demand and electricity prices are likely to rise significantly in the next three decades. QF contracts represent an important tool for managing this demand, limiting consumer exposure to market risks, and providing a less risky option for replacing large retirements of coal-fired generation than relying on the incumbent utilities alone.

2. The NOPR's Conclusion That Projects Can Be Financed Without Fixed Energy Rates Is Unsupported and Based On Faulty Evidence.

The second incorrect assumption supporting the proposal to eliminate the requirement for fixed energy prices is that QFs will be able to obtain financing to support further development even without such fixed energy prices. But the NOPR provides no credible basis to assume that variable energy rates will support QF development. QFs must be financeable to exist, and QFs cannot be financed without stable, long-term contracts. Making the energy component of contract prices variable eliminates stable, long-term pricing, and will therefore make most, if not all, QFs unfinanceable.

As the Commission itself noted in Order No. 69 and on numerous occasions since, developers and owners of QFs must have the option to enter into long-term contracts with predictable prices to provide the "certainty" necessary to invest in a generation facility in the market controlled by reluctant utility purchasers.[58] The Commission adopted this regulation "to reconcile the requirement that the rates for purchases equal the utilities' avoided cost with *<u>the</u> <u>need</u> for [QFs] to be able to enter into contractual commitments <u>based</u>, <u>by</u> <u>necessity</u>, <u>on</u>*

58 Order No. 69, 45 Fed. Reg. at 12,224.

estimates of future avoided costs."[59] Since 1980, "FERC has 'consistently affirmed the right of QFs to long-term avoided cost contracts or other legally enforceable obligations with rates determined at the time the obligation is incurred, even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred.'"[60]

The NOPR casts this long-recognized necessity of QFs aside and violates the statutory non-discrimination principle. Instead of continuing to encourage QFs, the NOPR proposes a discriminatory framework. Utilities can rate-base long-term investments, thereby ensuring that they can recover their capital investments plus an authorized return, and then also recover their actual operating costs under traditional cost-of-service ratemaking.[61] In contrast, under the NOPR's proposal for variable energy pricing, the QF is deprived of even a reasonable ability to forecast its ability to recover its costs, much less guarantee such recovery. If adopted, the proposed rule will therefore ensure that utilities continue to dominate the generation market, with negative consequences for consumers, innovation, and the health of FERC-regulated markets.

As evidence from the investment rating agencies demonstrates, using variable short-term pricing as the basis for setting long-term avoided cost rates will fundamentally undermine PURPA by eliminating, or at least severely restricting, the ability of QFs to obtain financing. For example, in its rating criteria for renewable energy projects, the Fitch Ratings agency notes that "[r]enewable energy projects operate typically on the basis of long-term PPAs, regulatory

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59 Order No. 69, 45 Fed. Reg. at 12,224 (emph. added).

60 *Allco Renewable Energy, Ltd. v. Mass. Elec. Co.*, 208 F. Supp. 3d 390, 398-400 (D. Mass. 2016) (quoting *JD Wind 1, LLC*, 130 FERC ¶ 61,127, 61,631 (Feb. 19, 2010), and holding that rate based on unknown, future market prices does not comply with 18 C.F.R. § 292.304(d)(2)(ii)).

61 *See, e.g.*, Ore. Rev. Stat. 756.040; *Gearhart*, 356 Or. at 220.

incentive mechanisms such as contracts for difference (CfDs), feed-in tariffs (FITs) and green certificates, or combinations thereof."[62] Fitch also explains that:

> Stability and predictability of power generation remuneration are highest for projects that have a secure revenue stream through long-term PPAs or regulatory incentive mechanisms insulated from market dynamics and where price indexation, if present, is based on transparent measures. Exposure to market price risk reduces remuneration predictability depending on the share of the associated revenues compared with the total. Indexation of contractual prices may also result in lower stability and predictability of remuneration depending on the complexity and transparency of indexation formulas.[63]

Accordingly, Fitch lists "Revenue Risk – Price" as a "Key Ratings Driver," noting that it evaluates the "[s]tability and predictability of power generation's remuneration" when evaluating debt financing of such projects.[64] A project is rated "stronger" on this criterion if prices are "fixed or indexed using simple, broad-based publicly available indexation formulas."[65] A project is rated "weaker" if pricing is based on "[v]ariable prices or indexed using opaque or complex indexation formulas," with "price indexation predictability" listed as a "relevant indicator" for this factor.[66] Hence, the greater a project's exposure to varying market prices, the lower its project rating will be, and the greater the risk that it cannot be financed.[67]

The Northwest Parties are also submitting the Declaration of Carol Loughlin, who has extensive experience in the financing of renewable energy facilities, and discusses the likely impacts of limiting QFs to variable energy prices. She concludes – as all other available data suggest – that variable pricing would impair or eliminate a prospective QF's access to project

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[62] "Global Infrastructure & Project Finance, Renewable Energy Project Rating Criteria," *FitchRatings* (Feb. 26, 2019), at p. 9, available at: https://www.fitchratings.com/site/re/10061770.
[63] *Id.* at 9-10.
[64] *Id.* at 1.
[65] *Id.* at p. 3.
[66] *Id.* at 3-4.
[67] *See id.* at 16-17.

financing, which is the most common source of capital for renewable energy projects. And she further confirms that the proposed reliance upon volatile short-term market pricing for most, or all, of a project's expected revenue will not provide lenders comfort that future revenue can reasonably be expected to cover financing costs.

The need for long-term fixed-price rates has also been recognized in state utility commission proceedings. For example, recent experience in Montana is instructive concerning the contract length necessary to assure that QFs can be financed and constructed. At the request of Northwestern Energy, the Montana Public Service Commission ("Montana PSC") reduced its standard 25-year QF contract term. Initially, the Montana PSC concluded that it should reduce the contract length to 10 years, but later concluded that term length was too short. In fact, Montana PSC Commissioner Bob Lake was recorded unknowingly on an open microphone agreeing that the shortened contract length "is going to kill [QF] development entirely," and, in light of the PSC's determination to cut avoided cost rates in half, stated that "the ten year [contract term] might do it if the price doesn't. And honestly, at this low price, I can't imagine anyone gonna get into it."[68]

The Montana PSC thereafter adopted a "symmetry" policy, which the PSC justified as follows:

> Accordingly, it would not be even-handed for the Commission to address this issue only with respect to QFs when the problem also occurs with non-QF resources, and often to a greater degree. Addressing excessive forecast risk necessarily requires symmetrical treatment of QFs and non-QFs so that, in limiting contract lengths, the Commission does not engage in discriminatory rate making for QFs. Therefore, the Commission

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68 *See Vote Solar et al. v. Montana Dept. of Public Service Regulation*, Montana 8th District Court, Cascade County, Docket No. BDV-17-0776 at 3 (April 2, 2019) (quoting Transcript of June 22, 2017, Montana PSC Work Session) (available at: https://billingsgazette.com/court-order-vote-solar-vs-psc-nwe/pdf_5728281d-ec7f-5c45-90f1-8e5b5aa95106.html).

> finds that, going forward, any resource the utility acquires or contracts with must be subject to the same standard.[69]

On reconsideration, despite Northwestern Energy's strong opposition, the Montana PSC refused to abandon the symmetry policy. However, after examining the amortization periods used for Northwestern's rate-based assets, some of which were in excess of 30 years, the Montana PSC concluded that the minimum contract length necessary to attract capital investment for both regulated utilities would be 15 years.[70]

Applying the available evidence, it is clear that, if adopted, the NOPR's proposal to base the energy component of long-term PURPA prices on highly variable indices like LMP, EIM, or the day-ahead Mid-C index would effectively eliminate the ability to finance QFs. This is particularly true for solar and wind projects, which have relatively low capacity value and therefore will depend to a greater degree than most other technologies on the energy component of the contract price to predict revenues that support project financing.

Further, the NOPR proposes to adopt a floating price for energy at a time when tax incentives, with relatively reliable value, are declining or disappearing. These tax incentives reduced project risks, and therefore improved their ability to obtain financing, by reducing the projects' cost basis as well as opening up the availability of non-traditional tax equity financing. As the tax incentives are phased out, QF projects will increasingly have to rely on traditional financing sources. Accordingly, the success of financing projects during the period when substantial tax credits were available says little about the ability of projects to obtain financing

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69 *In re Northwestern Energy's Application for Interim and Final Approval of Revised Tariff No. QF-1,* Order No. 7500c, Docket No. D2016.5.39 at ¶ 114 (July 21, 2017).

70 *In re Northwestern Energy's Application for Interim and Final Approval of Revised Tariff No. QF-1,* Order No. 7500d, Docket No. D2016.5.39 at ¶¶ 76-94 (Oct. 5, 2017). The Commission's determination was overturned in the Montana District Court on the ground that it had not provided adequate evidence to justify its decisions. An appeal of that decision is currently pending in the Montana Supreme Court, Cause No. DA 19-0223.

when those incentives are no longer available, and the Commission's conclusion that projects can be financed despite having variable energy rates fails because it relies heavily on anecdotes from the period when significant tax incentives were available.

In addition, it is already difficult to finance small renewables because their size increases financeable risks.[71] For example, where one turbine in a wind farm of ten turbines is out of service, that project loses ten percent of its output. By contrast, the outage of one turbine in a farm of 100 wind towers has only a negligible impact on the project's overall output. The higher risk profile of smaller projects make them more difficult to finance because lenders do not want to assume these additional risks.

Similarly, small QF projects bear transactions costs for attorneys, due diligence, financing costs, etc., that are often comparable to the costs incurred for larger projects, or at least constitute a proportionally larger share of the costs of constructing a smaller project. This also adds to the challenge of financing smaller projects.

The NOPR, if adopted, is likely to slow the deployment of new technologies and innovations, such as energy storage, hydrogen fuels, and other advanced renewable energy technologies. Because they have not been widely deployed, these technologies necessarily carry with them added technology risk not shared with existing, well-established technologies. As noted in Order No. 69, there is a "need for certainty with regard to return on investment in new technologies."[72] Adding price risk to projects that already carry with them significant technology risk only increases the difficulty of financing such projects. This will occur at a time when new technologies, especially storage and variants such as solar-plus-storage, are

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[71] The attached Declaration of Carol Loughlin demonstrates the difficulties of financing small facilities.

[72] Order No. 69, 45 Fed. Reg. at 12, 224.

desperately needed to help ensure that the transition to renewable energy now underway in much of the country can proceed with minimal risks to reliability and with as much economic stability as possible.

The NOPR cites several pieces of evidence to support its claim that variable energy pricing will not preclude the financeability of QF projects. The evidence does not stand up to scrutiny.

Initially, the NOPR claims that fixed capacity payments coupled with variable energy payments have been sufficient to encourage financing of significant new capacity in the ISO and RTO markets.[73] This is incorrect. This reasoning has no applicability in regions like the Northwest where there is no such organized market. As discussed further below, the Commission has struggled to develop effective capacity markets in the RTO/ISO regions. Using short-term LMP energy prices is at the heart of this problem because they do not provide adequate incentives for long-term investment in generation.

Similarly, the Commission's claim that fixed/variable contract rates in non-ISO markets have been effective in encouraging construction of gas turbines[74] fails to support the NOPR's claims. The example cited is a contract in which the IPP operator of a gas turbine receives a fixed capacity payment while the energy price is indexed to the price of natural gas. In the context of a gas turbine, this contract structure is effective because the capacity payment is stable and therefore can be leveraged to finance the plant. The energy price acts to eliminate the plant's fuel risk by indexing that price to the price of natural gas, thereby assuring that the IPP will always have sufficient revenue to pay for the cost of its primary input for generating electricity at any given point in time. The example therefore proves the opposite of what the

[73] NOPR at P 70.
[74] NOPR at P 70 & n. 114.

Commission claims – the project can be financed because the capacity payment provides an assured and steady income stream while the energy price eliminates the risk of volatility in the natural gas markets. This is the opposite of what the NOPR would accomplish because it would expose QFs directly to the risk of volatility in the LMP, EIM, or day-ahead Mid-C prices. Put another way, the construct would work only if the Commission required capacity payments sufficient to permit QF projects to be financed and required the variable energy component to be structured in a way that removes market risk from the QF. The other evidence cited in the NOPR is taken out of context.[75]

The Commission also claims that the industry has "developed forecasts" of competitive markets, but the evidence the Commission cites is in a completely different context – whether a transmission project is eligible for rate incentives. This evidence also addresses a completely different question – whether transmission expansion would reduce overall costs by allowing dispatch of less-expensive wind resources to displace higher-cost fossil resources.[76] Even if the

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[75] The NOPR cites the Technical Conference testimony of Don Sipe, who testified on behalf of the American Forest & Paper Association. *See* NOPR n. 114 (quoting Mr. Sipe as stating, "("Now you sign a long-term IPP contract. That contract [has] got a variable energy cost in it"). Examining the full context, it is clear that the excerpt of testimony cited by the Commission is a hypothetical contract included with a utility that is included in the utility's rate base, not a QF contract. Further, Mr. Sipe's testimony is clear that he disagrees with one of the NOPR's central propositions, that QF prices are systematically higher than market prices, and that the proper solution to that problem, even if it exists, is to refine the avoided cost calculation, not to fundamentally alter the rules as the NOPR proposes. Transcript of FERC Technical Conference, AD16-16-000, June 29, 2016, at 149-54. The language cited by FERC actually appears on page 153 of the Technical Conference transcript, not page 178 as the NOPR citation suggests.

The Commission also cites (NOPR n. 115) the Comments of the Solar Energy Industries Association, Docket No. AD16-16-000 (filed June 29, 2016), but the context of that excerpt makes clear that fixed prices are essential to finance any project, including a QF: "For a project to be financeable, the developer must obtain a PPA that includes: *Fixed Price*: A predictable stream of revenue from the project asset is the fundamental basis of any project financing. . . . Developers need rates for such sales of energy and/or capacity to be fixed, based on avoided costs calculated at the time the obligation (of the QF to sell and the utility to buy) is incurred, rather than varying over time." *Id.* at 3-4. Certainly nothing in the referenced comments supports the Commission's claim that a fixed capacity price, no matter how small, would be sufficient to support long-term financing of QFs.

[76] NOPR at n. 116 (citing *ITC Great Plains, LLC,* 126 FERC ¶ 61,223 at P 43 (2009)).

dispatch study cited by the NOPR provides substantial evidence of reduced generation costs in that case, it says nothing about whether financial institutions would consider such forecasts to be sufficiently robust or risk-free to justify financing of QFs. As noted above, the Northwest Coalition agrees that price forecasts based on long-term prices established at liquid market hubs can be a valid basis for establishing long-term avoided costs. But those price forecasts are valid only to the extent they reflect long-term, not short-term, prices, and valid, arms-length transactions.

The NOPR also asserts[77] that hedging is available to reduce risks of fluctuating prices, suggesting that price hedges would be sufficient to satisfy lenders otherwise leery about financing a project with a variable energy rate. To start with, the evidence cited by the Commission provides absolutely no support for the proposition that hedging might support financing of generation plants exposed to variable energy prices. Rather, it is lifted at random from an entirely different context, the Commission's discussion of whether energy storage resources should pay wholesale or retail rates for energy used to charge those resources in the RTO/ISO markets. Neither the quoted paragraph nor the surrounding section even mentions financing, let alone provides any evidence for the proposition that hedging transactions would be sufficient to allow financing of generation projects exposed to energy market risk through variable energy pricing.[78] There is a complete lack of evidence that hedging has ever been

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[77] NOPR at P 72.

[78] The NOPR (at n. 117) cites the Commission's Order No. 841, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators,* 162 FERC ¶ 61,127 (2018). The NOPR cites to paragraph 299 of Order No. 841 but the quoted language actually appears in paragraph 294. Nothing in paragraph 294 or any of the discussion related to that paragraph discusses project finance and paragraph 294 contains only a passing reference to hedging in the RTO/ISO markets. This falls far short of constituting substantial evidence for the NOPR's claim that the availability of hedging will permit generation projects to be financed under PURPA even if they are exposed to market risk through variable energy rates.

successfully used to mitigate a project's risks of exposure to market price variability and thereby to permit financing of the project. And, as the evidence discusses only hedging within the ISO/RTO regions, there certainly is no evidence that such a hedging approach to resolve financing issues is possible in the Northwest or other areas outside the ISO/RTO regions.

In any event, if QFs are forced to rely on hedging transactions, this does nothing more than drive up their costs.[79] Hedges are not free. On the contrary, the greater the volatility of a market, the more it costs to hedge that volatility. Worse, hedging only adds costs that QFs face uniquely because the regulated utilities can pass any financing costs of their rate-based facilities onto their ratepayers and have no need to hedge to ensure financeability. Hence, even assuming that hedging could overcome the financing problems created by the NOPR's proposal to permit variable energy rates that expose QFs to market risk, hedging is not available to most QFs, and the Commission's suggestion that hedging is a cure-all for these financing problems is therefore incorrect.

Finally, because hedging occurs on markets that are subject to complex regulation under the Dodd-Frank Act, the NOPR proposal could create significant compliance costs for QFs. These costs are disproportionately large for most QFs because of their small capacity. In contrast, most incumbent utilities have energy trading floors which create Dodd-Frank compliance issues and therefore have already invested in the legal resources necessary for compliance. Hence, even if the NOPR's conclusions regarding hedging were otherwise supported by substantial evidence, the proposal should be rejected because it imposes unique burdens on QFs and therefore creates artificial competitive advantages for incumbent utilities. For the same reason, to the extent incumbent utilities purchase power under PURPA contracts,

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[79] The attached Declaration of Carol Loughlin further discusses unlikelihood of successfully using hedging as an option for financing in the context relevant to the NOPR.

the utility can add that power to its much larger portfolio and manage it on a portfolio basis, including the purchase of hedges needed to protect ratepayers from market volatility. Because of the relative size and expertise of the utility, placing the burden for hedging on the utility rather than on individual QFs is likely to be far less costly and far more efficient overall.

The Commission also claims that data purportedly showing that IPPs have been able to construct generation facilities even if not certified as QFs supports using fluctuating short-term rates to established avoided energy costs. The claim is another *non sequitur.* The data cited by the Commission show only that IPPs have built significant capacity and says nothing about the underlying contracts that supported capitalization of these projects. In the absence of data demonstrating that IPPs have been able to build these projects despite exposure to fluctuating short-term market prices, the cited evidence fails to support the keystone proposition for this portion of the NOPR – that generation projects can be financed even if they are exposed to unstable and highly volatile short-term market prices.

If anything, the evidence cited by the Commission supports the conclusion that the existing PURPA rules, including fixed long-term avoided cost rates and long-term contracts, are essential to support financing of PURPA contracts. For example, the EIA report cited by the Commission[80] states that the rapid growth of IPP-owned generation in North Carolina is attributable to the requirement that North Carolina requires 15-year QF contracts with a capacity up to 5 MW, and contrasts this approach with other states like Arizona and Nevada, where QF solar development has lagged despite better solar resources because those states offer "shorter contract terms" or "lower capacity thresholds."[81] The report also notes that PURPA

[80] "North Carolina Has More PURPA-Qualifying Solar Facilities Than Any Other State" *EIA, Today in Energy* (August 23, 2016), cited at NOPR at P 74 & n. 118.

[81] *Id.*

remains relevant in the Southeast and Northwest because these regions lack an RTO or ISO.[82] There is nothing whatsoever in the EIA report that supports the Commission's assertion that QFs could be financed even if they are exposed to short-term market risk through energy rates that vary with LMP, EIM, or day-ahead Mid-C prices.

The same is true of the other data cited by the Commission. It simply shows growth in IPP-owned generation, with no indication of how that generation was financed or whether the underlying contracts exposed the projects to significant market risk.[83] As the NOPR concedes, this evidence does not support "the conclusion that substantial non-QF capacity is being financed and constructed without any form of fixed revenue to support financing."[84] But that is exactly the evidence the Commission must provide to support its claim that generation projects can be financed even without a fixed energy price component. In the absence of that evidence, the Commission lacks substantial evidence to support the NOPR proposal and comply with PURPA's directive that the Commission continue to encourage QFs.

The NOPR also claims[85] that its proposal is justified because many states have drastically shortened terms for standard PURPA contracts. While the Commission is certainly correct that these decisions have been "especially harmful" to QF projects -- Idaho's decision to reduce certain QF contracts to two years, for example, has effectively ended wind and solar PURPA development in that state[86] – this is a symptom of the Commission's unwillingness to specify a minimum acceptable term for QF contracts beyond generally stating that contracts

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82 *Id.*

83 *See* EIA evidence cited at NOPR at PP 74-75 & nn. 119-126.

84 NOPR at P 76.

85 NOPR at P 77.

86 *See* Idaho PUC Case Dockets, containing no contract approval cases for wind or solar QFs since issuance of Idaho PUC Order No. 33357 on August 20, 2015, which reduced contract terms to two years for all wind and solar QFs over 100 kW in capacity. Available at: https://puc.idaho.gov/electric/electric.htm.

must be "long enough to allow QFs reasonable opportunities to attract capital from potential investors."[87] As we discuss further below, rather than permitting the states to unilaterally write PURPA out of existence by imposing unreasonably short contract terms, the Commission should require QF contract terms to be at least as long as the terms over which incumbent utilities are permitted to amortize their investments in similar resources.

Finally, the Northwest Coalition notes that we agree with the Commission's conclusion[88] that, should the Commission adopt the proposal permitting floating avoided cost rates for energy, states should continue to have the flexibility to continue to impose fixed energy rates in QF contracts. The Northwest Coalition also supports the Commission's proposal[89] that, to the extent states use one-part QF rates, those one-part rates must be fixed.

3. Additional Requirements Would be Needed Before the Commission Could Seriously Consider Allowing Variable Energy Prices

The NOPR recognizes that some states have imposed very short contract terms as a "solution" for the supposed problems caused by long-term QF contracts,[90] but does nothing about this. If the Commission moves forward to allow for non-fixed energy pricing, it should at least require additional protections for the other critical elements of a long-term PURPA contract.

First, a minimum length of contracts must be expressly required. It would be reasonable to require contract lengths be offered of at least 20 years after commencement of sales under the agreement or the length of depreciation schedules approved for incumbent investor-owned utilities. Otherwise, short contract terms will also deprive QFs of fixed (or

87 *Windham Solar LLC*, 157 FERC ¶ 61,134, at P 8 (Nov. 22, 2016).
88 NOPR at P 79.
89 NOPR at PP 80-81.
90 NOPR at P 77.

any) capacity payments because utilities are typically capacity sufficient in the near term to ensure the ability to serve their retail load. Experience demonstrates that the uncertainty of the combined effect of short-term contracts and lack of fixed rates will be fatal to QFs – as noted earlier, in the years since the Idaho PUC reduced the term length for wind and solar QFs to two years, PURPA wind or solar development has stalled and no PURPA wind or solar contracts have been executed; likewise, despite more recently revamping its implementation of PURPA to allow for QF development, Washington used five-year contracts for years, which limited QF development in the state to less than a handful of projects.[91]

Second, before the Commission could consider moving forward with allowing use of non-fixed energy rates, it should adopt strict parameters for determining fixed capacity rates. Otherwise, the Commission leaves the QFs at risk of under-forecasted capacity needs, which would further undercut legitimate efforts to at least forecast some element of a prospective QF's revenue stream to support efforts to build QF capacity.

The experience in Northwest states demonstrates that capacity rates offered by a utility can underestimate the utility's actual capacity acquisition plans. The Oregon PUC has determined to pay QFs a capacity rate of an avoided generation facility only during the portion of the contract after which the utility is forecasted to acquire a major resource in its resource

[91] Despite similarities to Oregon, PacifiCorp's Washington territory has resulted in almost zero QF development and demonstrates that severe rules will drastically limit the opportunity for new QF development. *See Post Technical Conference Comments of the Community Renewable Energy Assoc.*, FERC Docket No. AD16-16, at Attachment 1 (filed Nov. 7, 2016) (containing a list of PacifiCorp's QF facilities which included only three Washington QFs totaling 4 MW). More recently, Washington revised its PURPA rules to provide for longer contract terms with fixed prices. *In re Amending, Adopting, and Repealing Section of WAC 480-106 and 480-107 Relating to the Public Utility Regulatory Policies Act*, Wash. UTC Docket No. U-161024, Order No. R-597 (June 12, 2019).

plan.[92] In other words, the QF will receive an energy-only fixed price in the early years of its contract until the utility had a plan to add a major generation resource (referred to as the "surplus" or "sufficiency" period due to capacity sufficiency). However, utilities have acquired capacity that was not forecasted for acquisition in a resource plan and, as a result, was not included in the capacity payments offered to QFs. Recently, PacifiCorp maintained avoided cost rates that indicated it was renewable resource sufficient for the next decade while simultaneously undertaking an unplanned procurement of a major renewable resource.[93] Similarly, a utility may engage in a major investment in an aging facility that amounts to a major capacity investment that the QFs and other IPPs never have the opportunity to compete against.

The same type of scenarios occurred in Idaho in the early 2000s and lead the Idaho PUC to eliminate the use a capacity surplus period altogether for many years. The Idaho PUC found that the utilities were acquiring resources during times when the load and resource forecasts used to calculate avoided cost rates indicated they were resource sufficient.[94] "Not once during this recent period of resource acquisition and building, it was noted, did a utility suggest that we should revisit avoided cost rates because perhaps the rates were too low, failed to reflect the

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92 *Re Investigation Relating to Elec. Util. Purchases from QFs*, Oregon PUC Docket No. UM 1129, Order No. 05-584 at 26-29 (May 13, 2005); *see also In the Matter of Pub. Util. Comm'n of Or., Investigation Into Resource Sufficiency Pursuant to Order No. 06-538*, Oregon PUC Docket No. UM 1396, Order No. 11-505, at 1-2, 4-5 (Dec. 13, 2011) (adopting same policy for avoided costs of renewable resources).

93 *In re PacifiCorp, dba Pacific Power: Investigation into Schedule 37 – Avoided Cost Purchases from Qualifying Facilities of 10,000 kW or less*, Oregon PUC Docket No. UM 1794, Order No. 17-239 (July 7, 2017) (noting numerous parties' concern that "PacifiCorp's current avoided cost prices, set at a time before PacifiCorp indicated its intent to procure renewable resources in the near term, do not reflect the company's true acquisition plans").

94 *In the Matter of Investigation of the Continued Reasonableness of Current Size Limitations for PURPA QF Published Rate Eligibility (i.e., 1 MW) and Restrictions on Contract Length (i.e., 5 years)*, Idaho PUC Case No. GNR-E-02-01, Order No. 29124, p. 8 (2002).

need for resources and were not sending an appropriate price signal to QFs."[95] The Idaho PUC determined that the utilities "in failing to update for changes in load/resource balance have compromised the public confidence in the reasonableness of its continued use."[96] Ultimately, the Idaho PUC found that a sufficiency period was unworkable and discontinued its use until many years later.[97] This history demonstrates that if the Commission ultimately allows for use of variable energy pricing, additional revisions to the regulations should also be adopted to prevent underestimates in capacity pricing mechanisms.

To reduce the risk of inaccurate capacity rates, the Northwest Coalition recommends the Commission's regulations should require that forecasted capacity rates be offered in a long-term contract of at least 20 years after commencement of sales under the agreement, at a minimum, during the following times:

- All years during the term of the QF's long-term contract after which the utility forecasted to be capacity deficit in its load and resource balance, as forecasted in its resource plan in effect at the time of the legally enforceable obligation; *and*
- Any time the utility is planning or undertaking actions to acquire a major generation resource or a major capital investment at an aging facility at the time of creation of the legally enforceable obligation.

Third, as an additional protection to ensure PURPA's non-discrimination requirement is met, the Commission should require symmetrical treatment of utility-owned generation if it is to repeal the requirement for fixed energy prices. This proposal would be consistent with the symmetry application discussed above, as adopted by the Montana PSC. The state would be

95 *Id.*
96 *Id.*
97 *Id.*

allowed to use variable energy pricing *only if* the state applies such variable energy pricing symmetrically to utility-owned resource cost recovery. In other words, the utility-owned generation's rate recovery must also be limited to (i) forecasted capacity value at the time of the acquisition based on the same capacity valuation used for avoided costs, which could be recovered through normal rate-basing techniques, and (2) any remaining recovery would be based on the avoided energy costs for as-available energy calculated at the time of delivery, without respect to what the utility's actual variable costs (e.g., variable O&M, fuel costs, etc.) are over the life of the plant. If the state does not elect to use this rate recovery mechanism or otherwise fails to enforce it, the state would not be authorized under the Commission's PURPA rules to deprive QFs of long-term fixed energy and capacity payments.

To summarize, a state's exclusive use of variable energy pricing would require its compliance with three non-discrimination protections: (i) the state must offer 20-year contract terms with fixed capacity payments to allow for forecasted capacity payments; (ii) the state must comply with provisions preventing inaccurate capacity forecasts; and (iii) the state must apply the variable energy pricing symmetrically to the utility's own generation resources. States would, of course, still be free to offer fixed energy and capacity payments to QFs instead of implementing these additional requirements.

C. The Proposals for Changes to As-Available Energy Pricing Are Flawed.

The NOPR proposes to amend the Commission's regulations to expressly allow for use of LMP, EIM, and short-term Mid-C index prices for as-available energy.[98] As noted above, the Northwest Coalition opposes allowing states to offer variable, i.e., time of delivery, energy prices as the only option offered to QFs. In our experience, very few QFs seek as-available

[98] NOPR at PP 43-58.

energy prices when long-term, fixed energy prices are offered, and therefore this aspect of the NOPR has very limited relevance unless the Commission adopts the proposal to allow states to offer only variable energy pricing. However, separately, the NOPR raises the question of whether these market pricing mechanisms are valid measures of time-of-delivery avoided costs of energy of the purchasing utility. In response, the Northwest Coalition opposes use of the LMPs and EIM indexes as a valid measure of avoided costs of energy, but would agree that the Mid-C index may reflect a time-of-delivery energy costs if restrictions on its use are applied.

1. LMPs and the EIM Prices Are Not a Valid Reflection of Avoided Energy Costs and Will Not Encourage Cogeneration and Small Power Production

As a general matter, the Northwest Coalition agrees competitive pricing should drive the wholesale power markets. But, in the continuing absence of organized and independently operated competitive wholesale markets in the Northwest, it is not possible to finance and build new construction without the assurance of long-term fixed pricing. If adopted, the NOPR's proposal to base QF pricing on highly variable short-term markets, such as LMP, EIM, or day-ahead Mid-C markets, will limit, not improve competition, because QFs will be stuck with no long-term assurance of investment recovery, and thus with no means to finance their projects, while regulated incumbents will be able to rate-base generation assets, thus guaranteeing long-term recovery of their investments.

Prices for long-term QF contracts should be set by reference to long-term price indices or other indicators that genuinely reflect the long-term costs of generation avoided by the purchasing utility. The NOPR, however, proposes to use highly-variable LMP and EIM prices to set long-term contract rates. The proposal makes no sense because these markets are not intended to provide long-term generation contracts. On the contrary, these prices are intended to apply to only very short-term energy needed to cover minute-by-minute variations in supply-demand conditions due to weather and other temporary factors such as short-term transmission constraints which are unrelated to the purposes and costs of long-term generation. LMP prices are hourly or day-ahead, not long-term. The EIM is currently limited to the five-minute market for balancing services. The EIM and spot markets are closing the gap of daily, hourly, and momentary imbalances with generation that has been built and is operating. The NOPR identifies no evidence that a rational investor would make the long-term investments necessary to build a generation facility assuming that those investments could be recouped solely from these short-term pricing mechanisms as they currently exist in the Northwest.

Indeed, as the Commission has noted, even in the context of demand-side management, where the necessity of recovering capital costs is not a major consideration, that "because LMPs fluctuate frequently," the LMP "creates the risk that LMP will not stay high enough for a long enough period of time to justify the costs associated with reducing load," and the Commission therefore found it necessary to "remove this risk from the customer" in order to ensure that adequate incentives exist to ensure participation in PJM's demand response program.[99] In the context of QFs, where revenue streams must be sufficiently large and steady to support project financing, it is even more implausible that using LMP to set avoided cost energy rates will be adequate to ensure QFs will participate in the market.

In fact, the Fitch ratings guidance discussed above identifies "merchant market price exposure" – that is, exposure to variable and unpredictable market prices – as a strong indicator that a project bears significant revenue risk and therefore represents a greater financial risk, while projects that are "insulated from market dynamics" have the highest ratings.[100] The

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99 *PJM Interconnection, LLC*, 103 FERC ¶ 61,167, at P 21 (2003).

100 "Global Infrastructure & Project Finance, Renewable Energy Project Rating Criteria," *FitchRatings* (Feb. 26, 2019), at pp. 3, 10, available at: https://www.fitchratings.com/site/re/10061770.

proposal to tie energy prices in QF contracts to these volatile short-term markets, if adopted, is therefore likely to render QFs unfinanceable and PURPA Section 210 a dead letter.

While the NOPR is correct[101] that LMPs are intended to promote more efficient use of the transmission grid, that is true only in the short term since factors such as temporary outages, equipment failures, weather extremes, and the like can cause LMPs to spike, but these have no impact on long-term transmission availability. Therefore, setting long-term avoided cost rates on LMP does not accurately address transmission congestion. While LMPs are a useful tool for developers to identify points on the grid where transmission is relatively more or less congested, developers have strong incentives to avoid congestion in any event, and they will generally be guided to areas of low congestion during the transmission interconnection process, whether or not they face LMP-based contract prices.

Further, if transmission constraints prevent a generator from delivering power to a specific node, the LMP at that node cannot be an appropriate measure of costs avoided by purchase of power from that generator.[102] Accordingly, unless transmission costs and constraints are taken into account, LMP by itself can never be an appropriate measure of avoided cost even for time-of-delivery pricing.

Additionally, LMP or EIM prices at the time of delivery are not a true measure of the long-term avoided costs of incumbent utilities unless those utilities are actually relying on those markets as a means to obtain long-term resources. As Don Reading's expert report attached hereto demonstrates, prudent utilities do not necessarily rely on these short-term, day-ahead markets over the long-term because they are too volatile and expose the utilities to excessive market risk. In fact, the Washington UTC has identified the Washington IOUs' overreliance on

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101 NOPR at P 48.

102 *Exelon Wind I*, 140 FERC ¶ 61,152, at P 52 (2012).

the short-term, day-ahead market, and the excessive price risk it creates, as a major concern.[103] Short-term market prices like EIM and LMP do not represent utilities' marginal cost for long-term resources unless the utilities actually rely on those markets for long-term resource purchases.

In addition, there is now substantial evidence that LMP prices are distorted by certain practices, such zero-cost bids, to operate plants uneconomically.[104] These practices may artificially depress LMP prices, meaning that until these flaws in LMP are repaired, LMP prices may not represent genuine prices, let alone provide a legitimate basis for setting long-term avoided cost energy rates.

In issuing this proposal, the Commission appears to have forgotten the hard lessons of the California market dysfunctions that crippled the West's electric systems for more than a year in 2000-01. As the Commission's investigative staff reported, the regulatory program adopted by California in 1996 required California's investor-owned utilities to purchase power

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103 *See, e.g.*, Washington UTC, *Acknowledgment Letter Attachment, Puget Sound Energy's 2017 Electric and Natural Gas Integrated Resource Plan,* Wash. UTC Docket Nos. UE-160918, UG-160919 (Revised June 19, 2018) ("However, in all three of the [Resource Adequacy] RA studies described in the IRP, the direction of RA beyond 2021 is clear: capacity markets are likely to fall short of meeting the RA standards. Unfortunately, the IRP does not expressly model or address market prices that can result from a tight capacity market. . . . both theory and historical experience suggest that demand will be inelastic, leading to very high costs for purchasing capacity from a tight market. Without a firm analysis that can establish a reliable boundary for those potential costs, the absence of a plan for eliminating reliance on market purchases over the 20-year plan carries excessive risk. Therefore, PSE should pursue and model
IRP alternatives to its historically heavy reliance on market resources to satisfy medium-term and long-term capacity needs.").

104 J. Daniel, "Out-of-Merit Dispatch of Regulated Coal Plants in Organized Markets," *36th USAEE/IAEE North American Conference* (Sept. 2018), available at: http://www.usaee.org/usaee2018/submissions/Presentations/Out-of-Merit%20Dispatch%20In%20organized%20Energy%20Markets%20Final.pdf; "Playing With Other People's Money: How Non-Economic Coal Operations Distort Energy Markets," *Sierra Club* (Oct. 2019), available at: https://www.sierraclub.org/sites/www.sierraclub.org/files/Other%20Peoples%20Money%20Non-Economic%20Dispatch%20Paper%20Oct%202019.pdf.

through the California Power Exchange ("CPX") "with little or no ability to purchase through forward contracts, exposing the utilities to the volatility of the spot markets without the ability to mitigate that volatility."[105] The Commission itself identified the requirement that all IOU purchases on the short-term CPX markets as "the most serious flaw in [California's] market design," noting that generators "benefit from the stable revenue stream of forward markets and have every bit as much incentive to avoid the volatility of the spot market as do purchasers."[106] The NOPR would repeat this failure, forcing QFs to accept unstable and unpredictable prices from short-term markets, placing QFs in the same untenable boat as the California IOUs during the 2000-01 crisis. The proposal therefore threatens both QFs and electric consumers – QFs because basing avoided-cost pricing on volatile short-term markets undercuts financing of those projects and consumers because, should QFs succeed in overcoming this financing hurdle, consumers would be exposed to these same volatile markets, including unpredictably high prices during periods of market scarcity, market power abuse, or constrained transmission capacity. As the California experience demonstrated, these markets can reach extreme and unpredictable highs under stress conditions.

The NOPR likewise fails to recognize the Commission's struggle to develop effective capacity markets in the ISO/RTO regions. At the heart of this struggle is the fact that the hourly and day-ahead markets, although generally characterized by substantial liquidity and robust price signals, have proved inadequate by themselves to provide sufficient incentives to ensure long-term adequacy of generation supply. The problem, often referred to as the

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105 FERC Staff, *Final Report on Price Manipulation in Western Markets, Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices*, FERC Docket No. PA02-2-000 at p. I-12 (March 2003).

106 *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Services Into Markets Operated by the CAISO*, 93 FERC ¶ 61,294 at 61,993-94 (2000), *order on reh'g,* 103 FERC ¶ 61,348 (2003).

"missing money" gap, arises because the revenue from short-term sales is inadequate to ensure enough long-term capacity to ensure reliability of the system.[107] In response, the ISOs, RTOs, and the Commission have been forced into a years-long effort to identify, develop, and approve new market mechanisms that provide sufficient incentives for long-term capacity while providing effective competition to ensure just and reasonable prices for electric consumers. This process is still ongoing.[108] The NOPR would condemn QFs to a world in which the "missing money" gap becomes permanent, ignoring the hard lessons that have been learned in attempting to solve the long-term supply problem in the organized markets.

The NOPR also ignores the lessons of the merchant generation model. Although merchant generators were once thought to be the future of electric generation in the United States, the merchant generation model is now in serious question. As one recent study concluded, "[t]he key weakness of the merchant generation business model is that generators' revenues generally do not cover the all-in cost of supply, which includes the cost of capital recovery as well as the variable cost of operation."[109] By confining avoided cost payments to the short-term markets, which by their nature cannot provide sufficient returns to ensure adequate capitalization of generation, the NOPR would place QFs in the same predicament as the merchant generators have experienced over the past two decades. Although the Commission may be able to cure this dilemma by imposing requirements of fixed capacity

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107 T. Jenkin, P. Beiter & R. Margolis, "Capacity Payments in Restructured Markets Under Low and High Penetration Levels of Renewable Energy," *National Renewable Energy Laboratory*, NREL/TP-6A20-65491 at 33 (Feb. 2016), available at: https://www.nrel.gov/docs/fy16osti/65491.pdf.

108 *See, e.g.,* U.S. Government Accountability Office, *Electricity Markets: Four Regions Use Capacity Markets to Help Ensure Adequate Resources, but FERC Has Not Fully Assessed Their Performance,* GAO-18-131 (Dec. 2017); *ISO New England, Inc.,* 165 FERC ¶ 61,202 (2018).

109 H. Wynne et al., "The Breakdown of the Merchant Generation Business Model: A Clear-Eyed View of Risks and Realities Facing Merchants," at 1 (June 2017), available at: https://www.wbklaw.com/uploads/file/Articles-%20News/2017%20articles%20publications/WBK-PRG%20Merchant%20Generation%20White%20Paper(1).pdf.

payments that will ensure they provide a sufficient revenue stream to permit QF capacity to be financed, there is still insufficient evidence that even that would solve the problem of variable energy pricing.

The Commission's claim that Congress somehow endorsed the use of LMP to set avoided cost rates by adoption of Section 210(m)[110] cannot be squared with the plain language of the statute. The key language of that statute, Section 210(m)(1), provides:

> (1) **Obligation to purchase**. After August 8, 2005, no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to—
> (A)(i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; *and (ii) wholesale markets for long-term sales of capacity and electric energy*; or
> (B)(i) transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, *including long-term and short-term sales*, and electric energy, *including long-term*, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or
> (C) wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).[111]

As the italicized language makes clear, Congress required non-discriminatory access to both short-term *and* long-term markets as a prerequisite to waiving PURPA's must-purchase requirement under Section 210(m). The Commission's assertion that this provision allows the Commission to rely solely on LMP prices, which are either real-time or day-ahead and not long-term, is therefore wholly misplaced.

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110 NOPR at P 45.

111 16 U.S.C. § 824a-3(m).

2. The Proposal to Allow Avoided Costs of Energy to Be Set by Reference to Liquid Market Hubs Is Not Acceptable As Proposed.

The Commission proposes to allow avoided-cost rates to be set by reference to prices in liquid market hubs,[112] but this proposal could make sense only with substantial changes.

First, FERC must recognize that, even at relatively liquid hubs like Mid-C, contracts are normally traded at terms no longer than five years, which is not long enough to support long-term investments in new generation.

Second, for reasons explained at greater length above, long-term prices are the appropriate measure, not short-term prices. Accordingly, it would be inappropriate for FERC to approve the use of indices for short-term hourly or daily contracts traded at these hubs as the only energy pricing option offered to QFs in long-term contracts.

Third, FERC must ensure that prices reported for long-term contracts in trading hubs are the result of actual competitive market forces. Accordingly, FERC should include safeguards to ensure that prices are set based on liquid trading with a sufficient number of competitors to assure effective price discovery, that prices are not subject to manipulation, and that reported price indices are accurate and not subject to mis-reporting or other forms of manipulation. Even at major hubs like Mid-C, this could be a major concern because there is no evidence supplied that markets for longer-term contracts remain liquid or will remain so after the Commission identifies the hub as acceptable in its regulations.

Finally, if the Commission elects to use a market hub to set avoided costs, the regulation should require the avoided costs to include the costs of transmission to and from such hubs except in cases where the utility's system directly interconnects with that hub.

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[112] NOPR at PP 51-61.

D. Competitive Solicitations Should Not Be the Exclusive Vehicle for QFs to Obtain a Long-Term Contract to Sell Energy and Capacity, and Competitive Solicitations Should Be Used to Set Avoided Costs Only Under Appropriate Conditions.

The Northwest Coalition urges the Commission not to rely on competitive solicitations as a substitute for the must-purchase obligation and caution the Commission against heavy reliance on such competitive solicitations.

The NOPR proposes to rely on competitive solicitations to set avoided cost rates, but the current proposal is unclear.[113] The NOPR proposes to add subsections (b)(8) and (e)(1) to Section 292.304 to "permit state flexibility to set avoided energy and/or capacity rates using competitive solicitations (i.e., RFPs), conducted pursuant to appropriate procedures."[114] Yet instead of actually explaining what RFP procedures might constitute "appropriate procedures" for setting avoided cost rates, the NOPR states it "does not propose in this NOPR to prescribe detailed criteria governing the use of RFPs as tools to determine rates to be paid to QFs[.]"[115] Instead of detailed requirements, the NOPR provides five general factors in proposed Section 292.304(b)(8) and explains in the NOPR that a "state may use an RFP to set avoided energy and capacity rates provided that such competitive solicitation process is conducted pursuant to procedures ensuring the solicitation is conducted in a transparent and non-discriminatory manner."[116]

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113 *See* NOPR at PP 82-88.

114 NOPR at P 82.

115 NOPR at P 86.

116 NOPR at P 87. The NOPR states:

> "These factors include, among others: (a) an open and transparent process; (b) solicitations should be open to all sources to satisfy that purchasing electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity; (c) solicitations conducted at regular intervals; (d) oversight by an independent administrator; and (e) certification as fulfilling the above criteria by the state regulatory authority or nonregulated electric utility."

Id.

The NOPR then seeks further comment on whether it should provide further guidance on whether "an RFP can be used as a utility's exclusive vehicle for acquiring QF capacity."[117] However, this sentence is somewhat perplexing because the proposed revisions to Sections 304(b)(8) and (e)(1) do not provide that utilities may use RFPs as the exclusive vehicle for acquiring capacity.

1. The NOPR Contains Inadequate Notice and Explanation to Allow RFPs as the Exclusive Means of Obtaining Long-Term Contracts

At the outset, the NOPR fails to explain (1) whether the Commission is proposing to merely clarify that a state could use the lowest offer prices submitted in an RFP to set the avoided costs of energy and capacity on a prospective basis for any QF seeking a contract until the next RFP, or (2) whether the Commission is proposing a radical change in its precedent by revising its rules to provide that a QF may only sell under a long-term contract if that QF wins a competitive solicitation.

As the NOPR recognizes, the Commission's well-established precedent, as set forth in *Hydrodynamics Inc.*, 146 FERC ¶ 61,193 (2014), is that PURPA requires a utility to purchase any energy and capacity made available by a QF and therefore precludes a utility from using an RFP as the exclusive means of offering to purchase QF energy and capacity. In *Hydrodynamics*, the Commission rejected the "Montana Rule", which imposed a "competitive solicitation process as the only means by which a QF greater than 10 MW can obtain long-term avoided cost rates."[118] The Commission explained, "a utility may refuse to negotiate with a QF at all, and yet the Montana Rule precludes any eventual contract formation where no competitive solicitation is held. Such obstacles to the formation of a legally enforceable

117 NOPR at P 88.
118 *Hydrodynamics Inc.*, 146 FERC ¶ 61,193, at P 33.

obligation were found unreasonable by the Commission in *Grouse Creek*, and are equally unreasonable here and contrary to the express goal of PURPA to 'encourage' QF development."[119]

The Ninth Circuit Court of Appeals has reached the same conclusion as the Commission did in *Hydrodynamics*. In *Winding Creek Solar LLC* v. *Peterman*, 932 F.3d 861 (9th Cir. 2019), the court reviewed the California PUC's implementation of PURPA that only provided a long-term fixed-price for energy and capacity to QFs who prevailed in a competitive solicitation through the Re-MAT program. But the Re-MAT had program caps that precluded Winding Creek from obtaining any long-term contract with fixed prices. The Ninth Circuit easily determined that "Re-MAT's cap on the amount of energy utilities must-purchase from QFs is impermissible under PURPA's must-take provision."[120] Thus, "a utility could purchase less energy than a QF makes available, an outcome forbidden by PURPA. 18 C.F.R. § 292.303(a)(1)."[121]

Notably, in the NOPR, Section 292.303(a) of the proposed regulations remains substantively unchanged from the existing provision interpreted in *Hydrodynamics* and *Winding Creek*. The proposed rule still states, in pertinent part, that "each electric utility shall purchase, in accordance with § 292.304, unless exempted by § 292.309 and § 292.310, any energy and capacity which is made available from a qualifying facility . . . ." The NOPR does not therefore appear to propose to allow for use of competitive solicitations as the exclusive means for QFs to obtain a long-term contract for energy and capacity, despite the confusing statements inviting comment on the topic in the NOPR.

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119 *Id.*
120 *Winding Creek Solar*, 932 F.3d at 865.
121 *Id.*

The Administrative Procedures Act requires the NOPR to serve basic notice functions, and in this case the NOPR does not do so to the extent the Commission is seriously considering amending its rules to allow for use of RFPs as the exclusive means to obtain long-term contracts.[122] The D.C. Circuit has explained, adequate notice must reveal the agency's views "in a concrete and focused form so as to make criticism or formulation of alternatives possible."[123] Similarly, the other circuit courts of appeal have explained "if the final rule 'substantially departs from the terms or substance of the proposed rule,' the notice is inadequate."[124] "An interested member of the public should be able to read the published notice of an application and understand the 'essential attributes' of that application. . . . [and] should not have to guess the [agency's] 'true intent.'"[125]

Therefore, if the Commission wishes to investigate whether RFPs should be the exclusive vehicle for sale of QF power under contracts for energy or capacity, it should reissue the NOPR with a clearly articulated proposal and explanation for the lawfulness and need for such a change in policy to allow for more detailed comment. The NOPR is wholly insufficient to justify a proposal to repeal the right to long-term contracts outside of the context of RFPs. To the extent such a proposal is made by the NOPR, it is not clearly articulated, and there is no rational explanation for how such a proposal would continue to encourage QF development and prevent discrimination against QFs as required by the statute. As the D.C. Circuit has explained, "If the notice of proposed rule-making fails to provide an accurate picture of the

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[122] *Small Refiner Lead Phase-Down Task Force v. Environmental Protection Agency*, 705 F.2d 506, 547 (D.C. Cir. 1983).

[123] *Small Refiner Lead Phase-Down Task Force*, 705 F.2d at 548 (quoting *Home Box Office, Inc. v. Federal Communications Commission*, 567 F.2d 9, 36 (D.C. Cir.), *cert. denied*, 434 U.S. 829, 98 S. Ct. 111 (1977)).

[124] *Chocolate Mfrs. Asso. v. Block*, 755 F.2d 1098, 1105 (4th Cir. 1985) (quoting *Rowell v. Andrus*, 631 F.2d 699, 702 n.2 (10th Cir. 1980)).

[125] *State of California ex rel. Lockyer v. FERC*, 329 F.3d 700, 706-07 (9th Cir. 2003).

reasoning that has led the agency to the proposed rule, interested parties will not be able to comment meaningfully upon the agency's proposals."[126] The agency cannot play "hunt the peanut" with the data and reasoning that it might believe will support its proposals.[127] Commenters, such as the Northwest Coalition, are left to guess what basis might exist to justify such a drastic departure from the Commission's existing precedent. On procedural grounds alone, therefore, the Commission should not adopt any rule that allows RFPs to be the exclusive means for QFs to sell energy or capacity under a long-term contract.

2. The Commission Should Not Authorize Use of RFPs as the Exclusive Means of Obtaining a Long-Term Contract for Energy and Capacity

To the extent that the NOPR proposes to allow for use of RFPs as the exclusive means of obtaining a long-term contract for energy and capacity, the Northwest Coalition strongly objects to such a proposal. As noted above, the Commission explicitly rejected such an implementation of PURPA in *Hydrodynamics*. The PURPA statute itself does not allow for utilities to refuse to purchase power from QFs outside the context of RFPs. The statute provides that the Commission's rules must "require electric utilities to offer to . . . purchase electric energy from such facilities."[128] In Order No. 69, the Commission correctly interpreted this statutory requirement "to impose on electric utilities an obligation to purchase *all electric energy and capacity made available from qualifying facilities* with which the electric utility is directly or indirectly interconnected, except during periods described in § 292.304(f) or during system emergencies."[129] The NOPR cites no evidence suggesting that RFPs will provide an

126 *Conn. Light & Power Co. v. Nuclear Regulatory Com.*, 673 F.2d 525, 530-31 (D.C. Cir. 1982).
127 *Id.*
128 16 U.S.C. § 824a-3(a).
129 Order No. 69, 45 Fed. Reg. 12, 214, 12,219 (Feb. 25, 1980) (emph. added).

adequate mechanism for QFs to sell their energy and capacity or any other basis to overrule the Commission's *Hydrodynamics* precedent.

While the Northwest Coalition agrees in principle that competition should be the motivating force in energy markets, the reality is that limitations remain on competition in large portions of the country, including in the Northwest. Unfortunately, our experience shows that utility-sponsored RFP programs often fall far short of genuine competition. As explained above, even when a state commission believes the utility has not run a truly fair and competitive solicitation, the utility is often able to acquire the resource anyway. The five generalized factors suggested in the proposed revisions to Section 304(b)(8) will not overcome the problems that are inherent in competitive solicitations in regions that retain a vertically integrated utility structure.

The practical effect of allowing states to use RFPs as the exclusive means of access to long-term energy and capacity contracts will be to repeal the must-purchase obligation for most, if not all, QFs. That is just the result that occurred in Montana before this Commission invalidated the Montana Rule in *Hydrodynamics* and the Montana PSC began requiring long-term contracts for QFs that were formerly subject to that rule. Notably, shortly after the Commission's *Hydrodynamics* decision, the Montana PSC began requiring long-term contracts for QFs outside of RFPs, and QFs formerly subject to that rule began obtaining contracts to sell power to Northwestern Energy at rates that are at or below the costs approved for Northwestern's own most recent resource acquisition, the PPL Hydropower Facilities.[130]

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[130] *E.g., In re NorthWestern Energy's Application for Preapproval of Hydroelectric Generating Facilities*, Montana PSC Docket No. D2013.12.85, Order 7323k (Sept. 25, 2014) (PPL Hydroelectric acquisition): *In re the Petition of NorthWestern Energy to Set Terms and Conditions of Contract Between NorthWestern Energy and Greenfield Wind, LLC*, Montana PSC Docket No. D2014.4.43, Order No. 7347a, at P 28 (April 14, 2015) (approving a levelized avoided cost rate for a 25-MW QF of $50.49/MWh, and noting comparability to costs of PPL Hydro acquisition).

Furthermore, as noted above, there is no basis to conclude that such an RFP might be won by an owner or developer of a smaller QF. No party has cited an example where a small renewable energy facility or cogeneration facility, e.g. 10 MW or smaller, has prevailed in a typical RFP for a major resource acquisition that allows bids for major generation facilities. That problem is particularly acute for QF developers and owners who are not regular participants in energy markets and RFPs, such as the irrigation districts operating small hydropower facilities in the Northwest. Any requirement to win an RFP to obtain a long-term PURPA contract should exempt such small facilities.

The Northwest Coalition stresses that development of effective RFP criteria is an exceedingly complex topic that would require additional investigation by the Commission if it were to seriously consider allowing for replacing the must-purchase obligation with RFPs. In state proceedings, some of the major proposals that have been investigated and would warrant investigation by FERC would include the following types of requirements: (1) require that the RFP include no utility-ownership options; or (2) if utility-owned generation may result, the RFP must be (i) administered and scored (not just overseen as proposed in the NOPR's five factors) by an qualified independent party, not the utility, (ii) any utility or affiliate ownership bid must be capped at its bid price and not allowed traditional cost-plus ratemaking treatment, and (iii) the product sought, minimum bidding criteria, and detailed scoring criteria must be made known to all parties at the same time, i.e., the utility or affiliate may not have an informational advantage in the RFP. Additionally, the option for long-term contracts should remain for small QFs and existing QFs outside of an RFP, due to the barriers such facilities would face no matter how well constructed the RFP rules might be.

Finally, to the extent that the Commission merely seeks to follow previous precedents, including *Hydrodynamics*, but seeks to clarify that the results of competitive solicitations may be used to set avoided cost rates in long-term contracts offered between solicitations, the Northwest Coalition cautions against heavy reliance on such RFPs. The Northwest Coalition is concerned that use of an RFP result to set avoided cost rates could lead to underestimating the utility's avoided costs at the time of the QF's later decision to create a legally enforceable obligation. For example, particularly with expired tax credits, the rates available currently in solicitations for renewable resources may be far lower than what could be obtained by the utility in a few years from now. Additionally, utilities regularly obtain resources outside of RFPs, or commit to major capacity upgrades to existing plants at costs that may exceed costs of generation from the latest RFP. The rules should not allow the state to ignore the costs of actual alternative resources available to the utility at the time that the QF commits to sell its energy and capacity to the utility.

In sum, the NOPR's proposed RFP factors will not ensure that QFs have a non-discriminatory opportunity to sell their output, and instead designing RFP rules that may ensure true competition is an exceptionally complex issue that would require additional time and consideration by the Commission.

E. Relieving Utilities In Retail Access States From Must-Purchase Obligation Violates PURPA

The NOPR proposes to relieve utilities of their PURPA must-purchase obligation to the extent those utilities have been relieved of their obligation to supply retail consumers through state retail choice programs.[131] This proposal is flatly illegal. PURPA mandates that FERC

[131] NOPR at P 89-92.

adopt rules that "*require* electric utilities" to "purchase electric energy from" QFs.[132] The Commission cannot unilaterally create exceptions to this must-purchase requirement. If such changes are needed, they must come from Congress. As Congress's adoption of Section 210(m) demonstrates, it is fully cognizant of changes in the electricity markets since PURPA was first adopted. The fact that Congress has limited the must-purchase obligation where IPPs can sell their output in competitive organized markets but that Congress has not modified the must-purchase obligation for utilities in retail access states is strong evidence of Congress's deliberate choice in this regard. The Commission is here attempting to usurp Congress's power to rewrite the statute.

Additionally, the Commission's existing regulations appear to already adequately address the concern at issue with this proposal. If a state with a retail choice program has relieved a utility of some increment of its obligation to serve load with long-term resources, that circumstance should be reflected in the utility's load and resource balance in its resource plan, and thus reduce the utility's need for capacity that could be avoided by purchases from QFs. In other words, any reduction in the long-term capacity needs of the utility occasioned by retail access should be reflected in the avoided capacity rates that would be offered to QFs. However, the NOPR's proposed regulation unreasonably appears to suggest that the utility would be relieved of its must-purchase obligation altogether, which is unlawful.

F. The NOPR's Proposed Reform Of "One-Mile Rule" Creates Unnecessary Uncertainty For QFs, Further Undermining Continuing Vitality Of PURPA

The Northwest Coalition opposes the NOPR's proposal to change the one-mile rule for QF certification into what would be, in effect, a 10-mile rule.[133]

[132] PURPA Section 210(a)(2), 16 U.S.C. § 824a-3(a)(2).
[133] NOPR at PP 100-107.

1. The Existing One-Mile Rule is Reasonable

As the NOPR notes, the statutory definition of a small power production facility describes the size limit as "a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 MW."[134] Ever since 1980, Section 292.204(a)(2) of the Commission's regulations has established that facilities are considered to be located at the same site if they use the same energy resource, are owned by the same person(s) or affiliates, and are located within one mile of each other, as measured from the electrical generating equipment of the facilities.[135] Additionally, the Commission explained that the existing regulations allow for adjacent facilities to use the same interconnection facilities without compromising their QF status by intentionally measuring the one-mile distance from the electrical generating equipment, not from "transmission lines and other equipment, including equipment used for interconnection purposes."[136] The Commission's existing regulations also measure the ownership criteria as of the time the facilities actually begin selling electric energy, and common development efforts of nearby facilities would not disqualify such facilities so long as the qualification criteria are met after energy deliveries were to commence.[137]

The existing rule is a reasonable means of implementing the statutory phrase "same site," particularly given the statutory directive to encourage QF development. The allowed use

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134 16 U.S.C. 796(17)(A).

135 18 C.F.R. § 292.204(a)(2)(i); Order No. 70, 45 Fed. Reg. 17,959, 17,965 (March 20, 1980).

136 *Northern Laramie Range Alliance*, 139 FERC ¶ 61,190, P 26 (June 8, 2012) (citing Order No. 70, 45 Fed. Reg. at 17,965).

137 *See CMS Midland, Inc.*, 50 FERC ¶ 61,098, at 61,279-61,278 (1990), *aff'd Mich. Municipal Coop. Group v. FERC*, 1993 U.S. App. LEXIS 7410 (D.C. Cir. 1993) ("[w]hether the facility satisfies the statutory and regulatory requirements for QF status before the facility produces electric energy is irrelevant."); *Citizens for Clean Air & Reclaiming Our Env't v. Newbay Co.*, 56 FERC ¶ 61,428, at 62,532-33 (1991); *Georgetown Cogeneration, L.P.*, 54 FERC ¶ 61,049, at 61,185 (1991).

of a shared interconnection reduces costs to develop generation facilities and reduces the need for duplicative and wasteful interconnection. Critically, the rule provides a bright-line test that can easily be applied, which is important to obtain financing and satisfy lenders to facilities located near other facilities as well purchasers of such facilities after construction.

2. The NOPR's Overbroad Rebuttable Presumption Will Frustrate the Purposes of PURPA

The Northwest Coalition opposes the Commission's proposed revisions to the currently effective one-mile rule. The NOPR proposes to revise the one-mile rule in ways that create uncertainty and exposes many facilities to the risk of protracted disputes with unpredictable results. Instead of a bright-line rule, the NOPR proposes to provide only a rebuttable presumption of compliance for facilities located between one and 10 miles from each other.[138] Moreover, the proposal appears to apply even to existing facilities that relied upon the current rules because the NOPR proposal states the new rule would apply to "certifications and recertifications that are submitted after the effective date of the final rule in this proceeding."[139] As proposed, it appears that the only assurance that could be obtained for such facilities would be if the facilities were to prevail in a protest to the certification filing, and even then, such facilities would only have such assurance until any further changed circumstances.[140] The

[138] NOPR at PP 100-101.
[139] NOPR at P 100.
[140] NOPR at P 104.

NOPR indicates it intends to consider "physical and ownership factors," which will be subject to ad hoc litigation with unpredictable outcomes.[141]

Given the statute's directive to encourage development of qualifying facilities, the existing regulation reasonably interprets the statutory definition of same site. Creation of a rebuttable presumption for projects one to 10 miles apart will create undue uncertainty for QFs attempting to finance projects. Additionally, the NOPR's proposed procedural fixes for the burden of this proposal overlook the ongoing effect of this new proposal for the entire life of the facility. This proposed rule will severely limit the transferability and thus value of any set of projects with aggregate capacity over 80 MW within 10 miles of each other for the entire life of the facilities. Even if the QFs can prove they meet the requirements to get through initial financing and construction, the proposed factors and risks of litigation would have to be considered whenever two separate facilities located within 10 miles are sold to new owners. The factors appear to be so broad they might even be triggered if two separate facilities located within 10 miles inadvertently decide to use the same contractor or consultant or equipment manufacturer. The practical effect of this rule will be to deter development of facilities using

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[141] The factors proposed by the NOPR include:

(1) physical characteristics including such common characteristics as: infrastructure, property ownership, interconnection agreements, control facilities, access and easements, interconnection facilities up to the point of interconnection to the distribution or transmission system, collector systems or facilities, points of interconnection, motive force or fuel source, off-take arrangements, property leases, and connections to the electrical grid; and (2) ownership/other characteristics, including such characteristics as whether the facilities in question are: owned or controlled by the same person(s) or affiliated persons(s), operated and maintained by the same or affiliated entity(ies), selling to the same electric utility, using common debt or equity financing, constructed by the same entity within 12 months, managing a power sales agreement executed within 12 months of a similar and affiliated facility in the same location, placed into service within 12 months of an affiliated project's commercial operation date as specified in the power sales agreement, or sharing engineering or procurement contracts.

NOPR at P 105.

the same motive force within 10 miles under PURPA. The Commission should therefore reject this core proposal.

If the Commission moves forward with a revision to one-mile rule, it should include substantially more specific parameters about what evidence a project would need to submit to demonstrate single-project status, and should make clear that this test has no applicability unless generators within one to 10 miles are owned by the same company or affiliates of the same company. The Commission has well-established criteria for determining ownership and control of QFs that were developed to ensure the formerly applicable utility-ownership limitation was not violated. The Commission has looked to the level of equity interest in the facility and determined that the "the decisive factors are the 'stream of benefits' from the project and control of the venture."[142] It defined "stream of benefits" to include entitlement to profits, losses, and surplus after return of initial capital contribution.[143] These criteria could be used to objectively evaluate whether two QFs within 10 miles are commonly owned or controlled, as opposed to also putting two separately owned and controlled facilities at risk of violating the rule based solely on physical characteristics.

The Northwest Coalition is especially concerned that some of the factors the Commission proposes to consider go beyond simply considering if two projects are commonly owned and controlled, and could potentially lead to a violation by two facilities that have entirely different ownership and control merely because they are located within 10 miles of each other. The Northwest Coalition strongly opposes use of common interconnection facilities as a factor because separately owned facilities are likely to share interconnection

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142 *CMS Midland, Inc.*, 50 FERC ¶ 61,098, at 61,278-61,279 (1990), *aff'd Mich. Municipal Coop. Group v. FERC*, 1993 U.S. App. LEXIS 7410 (D.C. Cir. 1993).
143 *Id.*

facilities to reduce costs and build off of existing infrastructure. Doing so makes sense and the Commission should not discourage project development by looking to common interconnections to conclude that two facilities are located at the same site. Additionally, given that there are only a limited number of qualified maintenance providers and other service contractors, the fact that two facilities use the same contractors should not be relevant to common ownership and control of two facilities. Likewise, the fact that two facilities are constructed within 12 months of each other could merely be evidence that the market conditions at the time favored construction of the facilities, not that the facilities are intended to be one facility.

If the Commission were to adopt this new rebuttable presumption, the Northwest Coalition agrees the Commission should adopt strict deadlines for objecting and resolving objections, but the NOPR seems non-committal on how quickly the Commission will rule on the dispute. No project will be able to rely on its qualification status during such a dispute. This type of litigation delay could compromise the viability of an otherwise commercially viable project. Thus, the Commission should provide a 60-day deadline after the filings are complete by which time a failure of the Commission to rule results in the objection being denied by operation of law.

3. If Adopted, the Rebuttable Presumption Should Not Apply to Existing Facilities Seeking Recertification

While the Northwest Coalition opposes adoption of the rebuttable presumption in any form, the Commission should at the very least ensure that any new rules do not apply retroactively to compromise the qualifying status of facilities that have already relied on the existing rules. As written in the proposed rule, the new test would apply even to existing QFs that were financed and constructed based upon the prior one-mile rule whenever such existing

QFs file a recertification form. Proposed Section 292.204(a)(2)(i)(C)'s rebuttable presumption for facilities between one and 10 miles would apply "for facilities for which qualification is filed on or after" 60 days after publication of the final rule. Additionally, the NOPR itself clarifies the new rule would apply to "certifications *and recertifications* that are submitted after the effective date of the final rule in this proceeding."[144] The applicability of this new rule is therefore overbroad because the Commission generally requires existing facilities to file a recertification form (or application) whenever "facilities fail to conform with any material facts or representations presented in an applicant's previous certification."[145]

This proposed rule would have an unlawful retroactive effect. The Supreme Court has explained that "statutory grant of legislative rulemaking authority will not, as a general matter, be understood to encompass the power to promulgate retroactive rules unless that power is conveyed by Congress in express terms."[146] Where the agency acts under the Administrative Procedures Act, as the Commission does here, the APA does not authorize retroactive rules.[147] The proposed rebuttable presumption will have the retroactive effect of applying the existing facilities seeking recertification. It will effectively bar the transfer or sale (or potentially any number of less significant changes) of existing assets that were lawfully qualified under the one-mile rule but cannot qualify under the new "10-mile rule" because they consist of more than 80 MW of aggregate capacity within 10 miles. There are many such facilities that would have their contractual and constitutional rights violated by this proposed retroactive effect of the NOPR's proposed rule.

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144 NOPR at P 100 (emph. added).

145 Order No. 724, 130 FERC ¶ 61,214, PP 56-59 (March 19, 2010); *see also* 18 C.F.R. § 292.207(d).

146 *Bowen v. Georgetown Univ. Hosp*., 488 U.S. 204, 208-09, 109 S. Ct. 468, 471-72 (1988)

147 *Bowen v. Georgetown Univ. Hosp*., 488 U.S. 204, 225, 109 S. Ct. 468, 480 (1988) (Scalia, J., concurring)

The Commission's past practice in developing new certification criteria is to apply the new criteria only to new facilities, not existing facilities seeking recertification. Most recently, the Commission revised Section 292.205(d) of its regulations regarding the new operation and efficiency certification criteria required by the Energy Policy Act of 2005 for cogeneration facilities. Those new criteria applied only to "any cogeneration facility that was either not a qualifying cogeneration facility on or before August 8, 2005, or that had not filed a notice of self-certification or an application for Commission certification as a qualifying cogeneration facility under § 292.207 of this chapter prior to February 2, 2006 . . . ."[148] The Commission also explained, "we clarify that there is a rebuttable presumption that an existing QF does not become a 'new cogeneration facility' for purposes of the requirements of newly added section 210(n) of PURPA merely because it files for recertification."[149] Only changes to the facility that lead it to be a whole new facility, "such as an increase in capacity from 50 MW to 350 MW,"[150] could trigger the applicability of the new qualification criteria. There is no basis to now apply the NOPR's proposed changes to qualification criteria retroactively to existing facilities.

At a minimum, therefore, any changes to the one-mile rule should not apply to existing facilities that have already filed a certification as QFs unless changes to the physical characteristics of their facility constitute a whole new facility after finalization of the new rule.

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148 18 C.F.R. § 292.205(d).

149 Order No. 671, 71 Fed. Reg. 7,852, at 7,865 (Feb. 15, 2006).

150 *Id.*

G. The NOPR's Proposal to Reduce the Size of QFs Subject to the Must-Purchase Obligation In Organized Markets to 1 MW Is Untenable.

The NOPR proposes to reduce the 20-MW threshold adopted in Order No. 688 to 1 MW.[151] The proposal is wholly unjustified. The Commission can identify no evidence indicating that the current 20 MW threshold is not working, has created problems, or that change is otherwise necessary. Nor can it identify any evidence suggesting that 1 MW is an appropriate threshold. Instead of substantial evidence, the NOPR offers only a series of platitudes and observations about rules adopted since Order No. 688 that lack any real-world justification. For example, the Commission asserts without evidence that "small power production facilities below 20 MW should be able to participate in such markets under most circumstances"[152] and that "it is fair to expect that small power production facilities above 1 MW can acquire the administrative and technical expertise necessary to obtain nondiscriminatory access to a market."[153] As we have demonstrated, the on-the-ground reality is that smaller QFs simply lack the resources to deal with these strategies, let alone to address the complexities of the energy markets, transmission interconnection rules, financing, and the many other burdens that independent power producers must bear.[154]

The other evidence cited by the Commission similarly fails. The Commission asserts that it has adopted fast-track interconnection processes for generators below 5 MW of capacity and has required energy storage resources as small as 100 kW to participate in the RTO/ISO markets.[155] While the Northwest Coalition supports both these reforms, the Commission offers

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151 NOPR at PP 126-130.
152 NOPR at P 126.
153 NOPR at P 127.
154 These points are demonstrated in the attached Declarations of Les Perkins, John Lowe, and Carol Loughlin.
155 NOPR at P 130.

no empirical evidence to demonstrate that they have achieved equal access to transmission for IPP generators. And, even taking the claim at face value, the reform does nothing for generators between 5 and 20 MW.

The NOPR overlooks that smaller producers necessarily have more limited resources and the energy markets systematically favor larger producers. For example, 25 MW is generally the standard "block" traded in in the wholesale markets.[156] This places smaller projects at a disadvantage because it is difficult to aggregate their output into a 25 MW block to be freely tradable, and, even where aggregation is possible, it imposes extra costs on small producers.

Smaller projects face similar limitations in obtaining transmission service. For example, for billing and scheduling purposes, the Bonneville Power Administration ("BPA") OATT requires project output to be scheduled in blocks no smaller than 1,000 kW per hour, equivalent to 1 MWh. Said differently, BPA, the largest wholesale transmission service provider in the (non-organized) Northwest market, effectively does not recognize transactions that are less than 1 MW. The OATT states:

> **13.8 Scheduling of Firm Point-To-Point Transmission Service**: . . . Hour-to-hour and intra-hour (four intervals consisting of fifteen minute schedules) schedules of any capacity and energy that is to be delivered *must be stated in increments of 1,000 kW per hour* [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. *Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes.*

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156 *See Cal. PUC v. Sellers of Long-Term Contracts*, 155 FERC ¶ 63,004, 66,086 (April 12, 2016) (finding "Traded forward contracts have standardized terms, generally offered in increments of 25 MW for peak, off-peak or all hours for delivery at recognized locations such as COB/Malin and Mid-C in the PNW or Palo Verde near the California/Arizona border. Brokers continually quote and publish bid and ask prices for such contracts.")

The same language applies to non-firm service. Hence, to accurately schedule at all, projects below 1 MW may need to pool their output with other generators using a common point of receipt, if any exist, and smaller projects above this threshold face a similar burden in scheduling increments of output that do not constitute a full MW. This could be a substantial portion of a small project's output. For example, if a 5 MW project is unable to schedule and transmit the last 900 kW of its output, this causes the loss of close to 20% of its total output.

The NOPR proposes to retain the existing threshold for cogeneration QFs, asserting that because the sale of electricity is a "byproduct" of the cogenerators' primary industrial processes, they are not likely to be "familiar with energy markets and technical requirements" as small power producers.[157] The NOPR cites no evidence to support the assumption that this is a problem only for cogeneration facilities. In fact, cogenerators are not the only type of QF whose primary products and expertise are in other markets, and who therefore may lack expertise in the complexities of the wholesale energy and transmission markets. For example, many CREA and REC members who operate QFs are, in fact, small irrigation districts that have no greater expertise in energy markets than would the large industrial concerns who operate cogeneration facilities. Such QFs are unlikely to possess the energy market sophistication the Commission supposes. This is explained in more detail by the attached Declarations of John Lowe and Les Perkins.

Some QFs in the Northwest are also operated by small rural electric cooperatives.[158] These organizations are focused on delivery of power to their members, and generally receive their wholesale power requirements from BPA. They therefore also lack the wholesale power

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[157] NOPR at P 129.

[158] For example, the Surprise Valley Electric Corp. operates the Paisley Geothermal Project as a QF in southern Oregon. *See* http://svec.coopwebbuilder2.com/content/paisley-geothermal-project.

market sophistication the Commission assumes because their primary business is electricity delivery and there is no basis to assume that these entities regularly engage in wholesale power transactions, hedging, transmission interconnection, Dodd-Frank compliance, analysis of LMP pricing, or the other complex tasks as the NOPR assumes they do.

The Northwest Coalition also opposes the NOPR proposal to permit reliance on RFPs to excuse the mandatory purchase obligation under PURPA Section 210(m)(1)(c). As we have discussed extensively above, the record demonstrates that, although RFPs are commonly used by utilities in the Northwest, they are not a categorically adequate substitute for PURPA's must-purchase obligation. The Commission should reject this proposal and require incumbent utilities to continue to bear the burden of demonstrating that IPPs have full access to organized wholesale markets outside the ISO/RTO regions before the mandatory purchase obligation can be excused under Section 210(m)(1)(C).

Finally, given the systematic limitations in the power markets discussed above that favor generation of 25 MW or more, the Northwest Coalition believes that the NOPR moves the threshold in the wrong direction. This evidence demonstrates that the threshold for Section 210(m) should be raised to 25 MW, not reduced to 1 MW.

H. While the LEO Concept Could Benefit From Greater Clarity, the NOPR's Proposal Is Flawed

The Northwest Coalition supports the Commission providing more guidance on the rules for creation of a legally enforceable obligation but strongly opposes the suggestion in the NOPR's proposed rule that a developer must demonstrate financial commitment to construct the facility before it can create a LEO. Here again, the NOPR is somewhat confusing regarding the intent of the proposal. On the one hand, the NOPR appears to support the Commission's existing precedent on creation of LEOs, stating that it does not intend to overturn existing LEO precedent.[159] Yet as written, the proposed rule would allow states and utilities to argue that a developer cannot create a LEO without first obtaining financing to construct the proposed facility, which would be a significant departure from existing precedent.

If a LEO could be conditioned on the demonstration of proof of financing of the facility, developers of renewable and industrial cogeneration facilities will face an inescapable chicken-and-egg problem because, as is common wisdom in the industry, a project will not be considered financially viable or financeable without a PPA or equivalent commitment from the utility.[160] The NOPR itself appears to acknowledge the fundamental notion that a LEO rule should not allow the utility to prevent a QF from creating a LEO.[161] But any requirement to demonstrate financing to create a LEO violates the fundamental rule that the utility's actions should not be allowed to deny the QF a LEO because the utility could prevent creation of a LEO simply by refusing to sign the PPA needed to secure such financing.

While the NOPR attempts to clarify the matter through use of several factors in the NOPR,[162] any such factors should be contained in the rule itself because courts will look first to the plain wording of the rules.[163] If factors will be used, they should be limited to factors that demonstrate the QF has engaged in a reasonable amount of development activity. The list of development activities in the NOPR is generally reasonable as long as none of the factors are

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159 NOPR at P 135.

160 The need for a power purchase agreement to obtain a financial commitment to construct the facility is further discussed in the attached Declaration of Carol Loughlin.

161 *See* NOPR at P 134 n. 174 (citing *FLS Energy, Inc.*, 157 FERC ¶ 61,211, at P 23 (2016)).

162 NOPR at P 141.

163 *See Exelon Wind 1, L.L.C. v. Nelson*, 766 F.3d 380, 396 (5th Cir. 2014) (looking to plain meaning of LEO rule instead of the Commission's commentary on its meaning in related orders).

necessarily dispositive.[164] For example, it may be reasonable to require the developer to obtain certain local permits prior to creation of a LEO, but other permitting requirements may not be feasibly obtained and finalized until late in the development process. As it stands now, however, the NOPR's proposed Section 292.304(d)(3) states only that the QF must demonstrate "commercial viability and financial commitment to construct its facility," which is a phrase that is not further defined in the rule itself. This will lead to unnecessary litigation. Moreover, and critically, the rule itself should expressly provide that a state commission may not condition obtaining a LEO on demonstration of financing to construct the facility, which in almost all cases for IPPs comes well after the PPA is executed.

In any event, the Northwest Coalition supports the Commission's clarification than any requirement to prove financial commitment does not apply to existing QFs when they seek new LEOs for their already-operating facilities.[165] However, as with the clarifying list of non-exhaustive factors, the Northwest Coalition urges the Commission to include this clarification in any final amendments made to the LEO rule because the rule itself should contain such clarifications to reduce disputes.

Finally, if the Commission makes any clarifications that impose more hurdles on establishing a LEO without a written contract, the Commission should also clarify that the new changes to the LEO rule do not affect the validity of any written contract executed between a developer of a QF and a utility regardless of the facility's development status. Nor should the

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164 The NOPR's proposed non-exhaustive list of factors provides that the state may require a showing that a "QF has satisfied, or is in the process of undertaking, at least some of the following perquisites: (1) obtaining site control adequate to commence construction of the project at the proposed location; (2) filing an interconnection application with the appropriate entity; (3) securing local permitting and zoning; or (4) other similar, objective, reasonable criteria that allow a QF to demonstrate its commercial viability and financial commitment to construct the facilities." NOPR at P 141.

165 NOPR at P 142 n. 183.

LEO rule preclude or bar a utility from executing a written power purchase agreement with a QF before the QF may be able to demonstrate compliance with the state's implementation the LEO rule. Consistent with Section 292.301(b) of the Commission's regulations, the LEO rule is necessary for those circumstances where a utility refuses to sign a contract and should not be used to invalidate or preclude the execution of a written contract.

I. The NOPR's Environmental Analysis Is Inadequate and the Finding of No Significant Impact Is Wrong

The Commission should conduct a full environmental analysis under the National Environmental Policies Act ("NEPA") before moving any further with the proposed major federal action at issue here. The NOPR's cursory determination that there is not likely to be a significant impact on the environment under the proposed rules – which would upend the only federal regulatory scheme mandating development of renewable energy facilities – is wrong. NEPA studies would require the Commission to more carefully consider the impacts of its proposed rules and would lead to better decision-making.

1. NEPA Requires an Environmental Impact Statement for Regulations that *May Have* an Impact on the Human Environment

NEPA requires an environmental impact statement ("EIS") be prepared for "every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment[.]"[166] The term "human environment" is "interpreted comprehensively to include the natural and physical environment and the relationship of people with that environment[]",[167] and "major federal action" includes "new or revised agency rules, regulations, plans, policies, or procedures[.]"[168]

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166 42 U.S.C. § 4332(C).
167 40 C.F.R. § 1508.14.
168 40 C.F.R. § 1508.18.

NEPA imposes a procedural requirement on federal agencies to take a "hard look" at the potential environmental consequences of the proposed action.[169] It applies where the proposed action "*may have* an impact on man's environment[.]"[170] The Ninth Circuit has explained: "[A]n EIS must be prepared if 'substantial questions are raised as to whether a project . . . *may* cause significant degradation of some human environmental factor. . . . The plaintiff need not show that significant effects *will in fact occur*, but if the plaintiff raises substantial questions whether a project may have a significant effect, an EIS *must* be prepared."[171]

NEPA requires that this evaluation occur early in the process of evaluating the proposed action.[172] In the words of the Council on Environmental Quality:

> An agency shall commence preparation of an environmental impact statement as close as possible to the time the agency is developing or is presented with a proposal (§ 1508.23) so that preparation can be completed in time for the final statement to be included in any recommendation or report on the proposal. The statement shall be prepared early enough so that it can serve practically as an important contribution to the decision-making process and will not be used to rationalize or justify decisions already made (§§ 1500.2(c), 1501.2, and 1502.2).[173]

In other words, the draft EIS should accompany the proposed rule, not be developed after the proposed rule.

Aside from the requirements of NEPA, the Commission's own NEPA regulations separately require, at a minimum, that the Commission complete an environmental assessment

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169 *N. Plains Res. Council, Inc. v. Surface Transp. Bd.*, 668 F.3d 1067, 1075 (9th Cir. 2011).

170 42 U.S.C. § 4332(A) (emph. added).

171 *LaFlamme v. FERC*, 852 F.2d 389, 397 (9th Cir. 1988) (internal quotations omitted) (emph. in *LaFlamme*).

172 *Id.* (citing 40 C.F.R. §§ 1500.1(a), 1501.1, 1502.5).

173 40 C.F.R. § 1502.5.

("EA") before any determination of no significant impact may be reached.[174] The Commission's NEPA regulations provide: "The projects subject to an environmental assessment are as follows . . . (12) Regulations or proposals for legislation not excluded under § 380.4(a)(2)."[175] In turn, Section 380.4(a)(2) of the Commission's regulations categorically excludes from the EA requirement only the following types of proposed regulations: "Proposals for legislation and promulgation of rules that are clarifying, corrective, or procedural, or *that do not substantially change the effect of* legislation or *regulations being amended* . . . ."[176] Here, the NOPR proposes to "substantively change the effect of . . . the regulations being amended[,]"[177] and therefore the Commission's own rules require an EA. The Commission's rules further provide that the environmental assessment will be available to be addressed at the time of issuance of the NOPR in the case of a rulemaking.[178] Thus, by rule, the Commission must, at a minimum, complete the requisite scoping and other process associated with an EA and then revise and reissue, or abandon, the NOPR after considering the issues developed in the EA.

2. The Proposed Rules Would Have a Significant Impact on the Human Environment

As noted above, NEPA requires an EIS if the proposed action *may have* a significant effect on the human environment. In this case, aside from the Commission's own rules requiring an EA at the minimum, there is no question that the proposed rules may have a significant effect on the human environment, and thus a full EIS is required.

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174 *Am. Bird Conservancy, Inc. v. FCC*, 516 F.3d 1027, 1033-34 (D.C. Cir. 2008) (vacating the Federal Communication Commission's rules and procedures for approving new communications towers where the agency failed to prepare the environmental analysis required by its own NEPA regulations).

175 18 C.F.R. § 380.5(12).

176 18 C.F.R.§ 380.4(a)(2) (emph. added).

177 *Id.*

178 18 C.F.R. § 380.11(a)(3).

The environmental benefits of PURPA are obvious. As the Smithsonian Institute has explained, since enactment in 1978, PURPA has been credited with a "tremendous – and unanticipated – spur to technological innovation on numerous non-traditional technologies for producing electricity."[179] The law's bedrock must-purchase obligation remains an important means by which efficient cogeneration and renewable generation facilities sell their output.

a. The Commission's existing regulations promote environmentally beneficial renewable and cogenerated energy

From the start, PURPA was intended to reduce use of fossil fuels by increasing development of renewable hydro, wind, solar, biomass, waste, or geothermal resources, as well as efficient cogeneration facilities.[180] The statute specifically requires the Commission to promulgate regulations "to *encourage* cogeneration and small power production" including regulations that "require electric utilities to offer to . . . purchase electric energy from such facilities."[181]

The bedrock regulations now proposed for repeal by the Commission include the requirement that utilities buy "any energy and capacity which is made available from a qualifying facility,"[182] and that in doing so, the utility provide the QF with option to choose a long-term fixed-price rate based on the utility's forecasted avoided costs for energy and capacity, as calculated at the time the QF incurs the contractual obligation to sell its electrical output.[183] These provisions, in particular, are critically important to QFs. As noted above, in developing these regulations, the Commission recognized that it was necessary to provide

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179 "Powering the Past: A Look Back," *Smithsonian Institution*, available at: http://americanhistory.si.edu/powering/past/history4.htm.

180 *FERC v. Mississippi*, 456 U.S. 742, 750-51 (1982).

181 16 U.S.C. § 824a-3(a) (emph. added).

182 18 C.F.R. § 292.303(a).

183 18 C.F.R. § 292.304(d)(2)(ii).

prospective developers and owners of QFs with the option to enter into long-term contracts with predictable prices.[184] If the Commission's regulations no longer meet the *need* for long-term fixed-price contracts, the market created by this legislative requirement will be significantly impaired.

PURPA is still the only federal law mandating that utilities purchase renewable energy. It is well-established that PURPA "was and remains a primary incentive for renewable power development."[185] While no data should be necessary, the available data confirms this fact.

The Energy Information Administration's data, cited by the NOPR itself, demonstrates PURPA's continued relevance to the renewable energy markets. Nationwide, the NOPR reasons, "Although almost 100 percent of all renewable resources in 1995 were QFs, since 2005 QFs have made up only 10 to 20 percent of all renewable resource capacity in service in the United States."[186] Even taken at face value, the NOPR fails to explain how eliminating the market for 10 to 20 percent of the nation's renewable energy facilities would have no impact on the human environment.

Moreover, the NOPR's 10-to-20-percent impact projection makes no attempt to quantify the impact in regions like the Northwest, where in some states without an RPS, existing and new renewable and cogeneration facilities must rely upon robust implementation of PURPA. While the NOPR notes that 29 states have an RPS,[187] that also means that 21 states have no RPS, and PURPA is the only law mandating that reluctant utilities purchase renewable energy and cogenerated energy. For example, the State of Idaho's legislature has affirmatively

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184 Order No. 69, 45 Fed. Reg. at 12,224.

185 Steven Ferrey et al., "Fire and Ice: World Renewable Energy and Carbon Control Mechanisms Confront Constitutional Barriers," *20 DUKE ENVTL. L. & POL'Y F. 125*, 140 (2010).

186 NOPR at P 22.

187 NOPR at P 23,

declined to adopt any renewable portfolio standard in its most recent Idaho Energy Plan.[188] In effect, PURPA remains the nation's bare minimum renewable energy mandate.

Similarly, the NOPR asserts that "regional transmission organizations (RTO) and independent system operators (ISO) serve two-thirds of electricity consumers in the United States[,]" which has "reduced the barriers to entry that faced QFs when PURPA was enacted."[189] But this statement ignores the fact that one third of energy consumers are not in such RTOs or ISOs, and instead QFs in one third of the country face the same obstacles that existed when PURPA was enacted.

More tellingly, EIA reports not cited by the NOPR further confirm the substantial amount of renewable capacity that results from PURPA. The EIA conducted a report on the recent capacity additions caused by PURPA.[190] The report demonstrates that in the past 10 years, PURPA has been a driver of the growth of renewable capacity in the United States. EIA report states that from 2008 to 2017, "14 GW" of capacity has come online from QFs certified as small renewable resources.[191] This is approximately 13.5 percent of all renewable generating capacity, and almost *one third of all solar photovoltaic (PV) capacity, added during that time period*.[192] The data also demonstrates that the PURPA development is most significant in states – like those in Southeast and Northwest – where there is no organized wholesale market, as the following chart of the top 10 states with QF capacity additions

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188 H.C.R. No. 34, 2012 Leg., 61st Sess. (Idaho 2012), *adopting* Idaho Legislature's Interim Committee on Energy, Environment and Technology, *2012 Idaho Energy Plan*, at pp. 9-10, 101 (Jan. 10, 2012), https://puc.idaho.gov/fileroom/reports/2012_idaho_energy_plan_final_2.pdf.

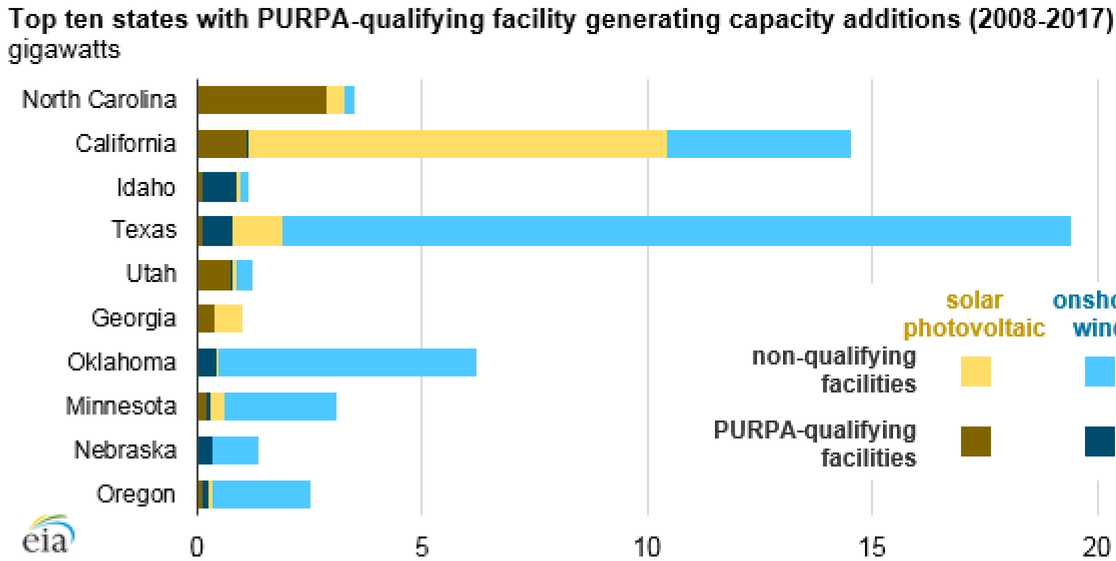
189 NOPR at P 25.

190 "PURPA-qualifying capacity increases, but it's still a small portion of added renewables," *Energy Information Administration* (Aug. 16, 2018), available at: https://www.eia.gov/todayinenergy/detail.php?id=36912

191 *Id.*

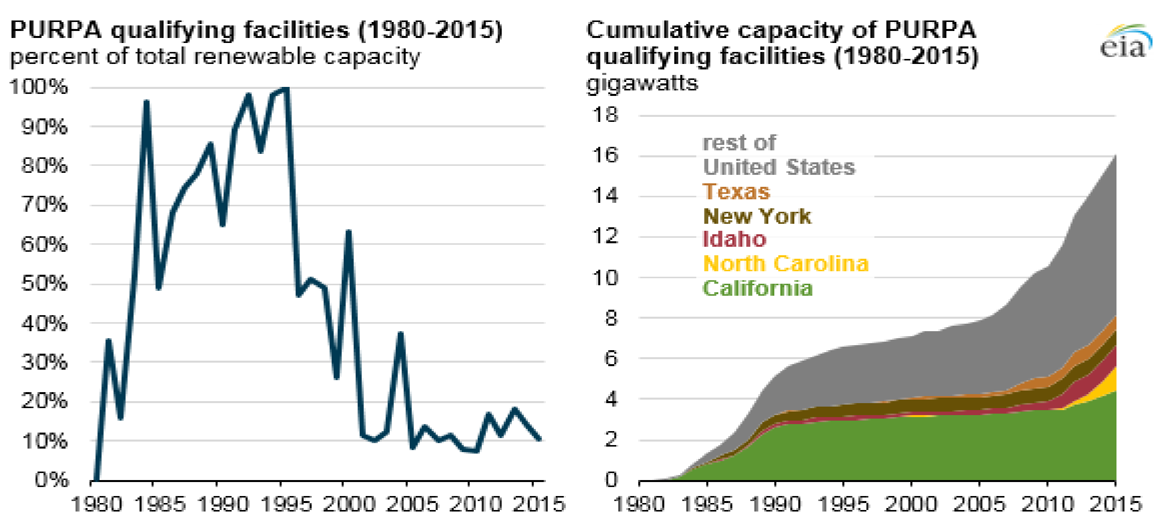
192 *Id.*

demonstrates:



Source: U.S. Energy Information Administration, *Annual Electric Generator Report*

Despite the NOPR's suggestion, more QFs are online now than at any time in PURPA's history. The EIA produced the following chart of data in another report[193] demonstrating, while non-QF renewables are indeed increasing, there remains a steady increase in QF capacity:



[193] "North Carolina has more PURPA-qualifying solar facilities than any other state." *Energy Information Administration* (Aug. 23, 2016), available at: https://www.eia.gov/todayinenergy/detail.php?id=27632.

Moreover, the NOPR acknowledges that "cogeneration has not achieved recent increases in penetration similar to renewable generation, and also remains more dependent on PURPA."[194]

Therefore, PURPA remains an important driver of both development of new renewable energy and cogeneration facilities, as well as retention of existing capacity – especially in areas where there is no organized wholesale market. As the EIA has explained, "The Energy Policy Act of 2005 allowed states with competitive electricity markets to opt out of PURPA, lessening PURPA's impact in states participating in regional transmission organizations (RTOs), but keeping PURPA relevant in areas such as the Southeast and Northwest that do not have RTOs."[195]

Indeed, Commissioner Glick recently reached the same conclusion in an article published in a major scholarly journal:

> Over its 40-year history, PURPA has been a major catalyst in the development of cleaner forms of generation. Indeed, much of the early growth of renewable resources took place pursuant to PURPA. In the last decade, PURPA's role has evolved after the Commission, in response to the Energy Policy Act of 2005, adopted a presumption that QFs with a net capacity above 20 MW and that are located in certain RTO regions are no longer entitled to a mandatory purchase obligation from incumbent utilities, since those QFs have access to a sufficiently robust market for their output.
>
> PURPA remains an especially vital tool for ensuring that relatively clean resources have adequate market access outside of the RTOs and ISOs. Although EPAct 2005 circumscribed the mandatory purchase obligation in well-developed markets, such as RTOs and ISOs, it left in place the structure of the 1978 Act outside of those regions. As a result, PURPA remains an important driver of renewable capacity installations, particularly outside of RTO/ISO markets. Indeed, there has been a significant increase in PURPA facilities in certain areas outside of RTOs and ISOs as the costs of renewable resources, especially photovoltaic solar, have declined. Although PURPA's success has helped to change

194 NOPR at P 24.

195 "North Carolina has more PURPA-qualifying solar facilities than any other state." *Energy Information Administration* (Aug. 23, 2016), available at: https://www.eia.gov/todayinenergy/detail.php?id=27632.

> the landscape for renewable resources, Congress's mandate to encourage the development of these resources, among others, remains on the books and as important as ever, especially in light of climate change.
>
> At the same time, the fact that Congress left in place PURPA's basic structure does not mean that the Commission cannot account for new technologies and economic trends in its implementation of the statute. To the contrary, it is the Commission's responsibility to ensure its regulations and orders implementing PURPA account for new technological developments in the roughly 40 years since the law was first enacted. Reducing our reliance on fossil fuels and encouraging competition is as important today as it was in 1978 when Congress made that goal a Commission priority when administering PURPA and the Commission must continue to adhere to the basic congressional intent underlying the statute.[196]

In sum, the existing PURPA rules certainly support maintenance of existing renewable and cogeneration capacity as well as continue to drive further development of these resources.

b. Renewable and Cogeneration QFs provide substantial benefits to the human environment

There is no question that QFs provide numerous environmental benefits, and that any scaling back of the must-purchase obligation through administrative rule will have a significant impact on the human environment. It is a well understood fact that renewable generation has a positive impact on the environment, which is why 29 states have enacted an RPS. To illustrate this point, the beneficial impacts of the Farmers Irrigation District's small hydropower QF are described in the attached Declaration of Les Perkins. As the Declaration explains, in addition to producing clean energy, the revenue from operations of the small hydropower QF provides critical support for the environmental upgrades to the District's irrigation distribution system, among other important benefits.

The NOPR also overlooks the cumulative impacts of the proposed action. The NOPR would eliminate the critical PURPA regulations at a time when other events and actions are

[196] Rich Glick & Matthew Christiansen, "FERC and Climate Change," *40 ENERGY LAW JOURNAL 1*, 38-39 (2019) (footnotes omitted).

adversely impacting the economics of renewable energy development, including the expiration of the production and investment tax credits, imposition of tariffs on solar panels and other critical components of renewable energy facilities, the Environmental Protection Agency's withdrawal of the Clean Power Plan, and the United States' withdrawal from the Paris Climate Accord. The cumulative impact of these actions and events must also be considered in evaluating the impact of the NOPR.

The pertinent Council on Environmental Quality regulation defines cumulative impact as follows:

> Cumulative impact is the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions *regardless of what agency (Federal or non-Federal) or person undertakes such other actions*. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time.[197]

The courts have further explained: "To be useful to decision makers and the public, the cumulative impact analysis must include some quantified or detailed information; . . . general statements about possible effects and some risk do not constitute a hard look absent a justification regarding why more definitive information could not be provided."[198]

Accordingly, when considered cumulatively with other events affecting the economics of renewable energy and cogeneration facilities, there is even less question that the proposed rule will have a significant impact on the human environment.

3. The NOPR's Finding of No Significant Impact Is Without Merit

In light of the above discussion, there is no question that the proposed rule is likely to have a significant impact on the human environment, and thus the Commission must complete

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[197] 40 C.F.R. § 1508.7 (emph. added).

[198] *N. Plains Res. Council, Inc. v. Surface Transp. Bd.*, 668 F.3d 1067, 1076 (9th Cir. 2011) (internal quotation omitted).

an EA and, most likely thereafter, a full EIS. The NOPR appears to make two primary arguments: (1) that the environmental impacts are "speculative",[199] and (2) the proposed rules will still encourage QFs.[200] Neither conclusion withstands scrutiny.

a. The environmental impacts are not too speculative to study

First, it is without merit for the NOPR to conclude that "any environmental impacts analysis . . . would be speculative and not meaningfully inform the Commission or the public of the revisions' impact on QF development . . . ."[201] The uncertainty of the environmental impacts of the proposed regulations only serves to support a conclusion that an EIS is necessary. In the words of the D.C. Circuit:

> As the court has admonished, "[i]t must be remembered that the basic thrust of the agency's responsibilities under NEPA is to predict the environmental effects of a proposed action before the action is taken and those effects fully known." *Scientists' Inst. for Pub. Info., Inc. v. Atomic Energy Comm'n*, 481 F.2d 1079, 1091-92 (D.C. Cir. 1973). A precondition of certainty before initiating NEPA procedures would jeopardize NEPA's purpose to ensure that agencies consider environmental impacts before they act rather than wait until it is too late.[202]

Indeed, the sole case the NOPR cites on this point – *N Plains Res. Council* – rejected the proposition that an agency's proposed action was too speculative to be evaluated in a detailed environmental analysis.[203] There, the Ninth Circuit explained NEPA requires the agency to "engage in reasonable forecasting. Because speculation is . . . implicit in NEPA, [] we must reject any attempt by the agency to shirk their responsibilities under NEPA by labeling any and all discussion of future environmental effects as a crystal ball inquiry."[204]

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199 NOPR at P 154.
200 NOPR at P 155.
201 NOPR at P 155.
202 *Am. Bird Conservancy*, 516 F.3d at 1033.
203 *See* NOPR at P 155 (citing *N. Plains Res. Council*, 668 F.3d at 1078-79).
204 *N. Plains Res. Council*, 668 F.3d at 1078-79 (internal quotation omitted).

While the Commission suggests that it cannot predict how states will implement the new regulations, it is certain that the states could not lawfully withhold fixed-price contracts under the current regulations. Furthermore, the NOPR's reasoning answers the wrong question – the question is whether the proposed rules *may have* a significant impact on the human environment. Given that test and the past history of state reluctance to implement PURPA, the Commission must assume that the states will eliminate the right to fixed-price contracts, and that the development of new QFs will grind to a halt. That type of analysis is precisely the type of analysis that must be done in a more detailed environmental assessment to determine if a full EIS is necessary.

The Commission's own past practice under NEPA belies the assertion that it would be too speculative to assess the likely environmental impacts of the proposed rule because the Commission has prepared EAs and EISs for equally far-ranging rules. The Commission prepared an EA when it first issued the very PURPA regulations the Commission now proposes to repeal.[205] The Commission evaluated the environmental impact of the rules proposed under Section 201 and Section 210 of PURPA in an environmental assessment and even conducted a full EIS to study the potential impact of one category QFs, diesel cogeneration facilities, withholding issuance of the rules certifying those facilities until the environmental impacts could be fully evaluated in an EIS, as NEPA requires.[206] The Commission also established a monitoring program "to alert the Commission to the likelihood or extent of market penetration by technologies which qualify under this program" in order to "produce information that may be relevant to taking appropriate action to protect the environment in the future . . . ."[207]

205 *Small Power Production and Cogeneration Facilities – Environmental Findings*, 10 FERC ¶ 61,314, 1980 FERC LEXIS 2148 (March 31, 1980).
206 *Id.* at **8, 80-84.
207 *Id.* at *11.

As part of the analysis, the Commission's PURPA EA included a "market-penetration analysis" that was "based on the assumptions that Section 210 of PURPA provides economic incentives to QFs by requiring utilities to purchase electricity from them at a price that equals the utilities avoided costs . . . ."[208] The study estimated the amount of development expected under the PURPA rules based on economic assumptions available at the time, concluding that the program was likely to "accelerate the development of industrial and commercial cogeneration, small-scale hydropower at existing dams, and municipal solid waste and wind power."[209] There is no reason why the Commission would be unable to produce a similar market impact study of the proposed rules here in order to transparently consider the likely impacts of its proposed action.

In a relevant passage, the Commission's environmental findings explained the environmental *benefits* of the PURPA regulations:

> Directly related to the energy and capacity provided by QFs are certain environmental benefits and tradeoffs that result from these rules. First, utilities will be able to defer or cancel construction of certain facilities, originally scheduled for construction between 1980-1995. These deferrals are expected to include some eleven -- 500 MW coal-fired steam plants, one-1,000 MW nuclear plant, a number of 75 MW gas turbines, and certain large scale hydropower and combined cycle installations. All of the environmental impacts associated with the construction and operation of these facilities would be avoided.[210]

Given this past finding, the Commission must now conclude that a drastic repeal of the critical provisions of the same regulatory scheme will result in a loss of the environmental benefits of QFs and thus require preparation of an EIS.

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208 *Id.* at *25.
209 *Id.* at *31.
210 *Id.* at *10.

Similarly, in perhaps its most far-reaching rulemaking, the Commission prepared a full EIS evaluating the impacts of Order No. 888.[211] In that EIS, the Commission analyzed whether the competitive market conditions fostered by open-access transmission would provide an advantage to power suppliers who produce power from coal-fired facilities that are not subject to stringent environmental controls on nitrogen oxides emissions.[212] In order to evaluate that potential impact, "staff prepared an FEIS based on computer modeling simulations of power generation patterns and NOx emissions likely to occur as a result of the rule[,]" using "widely accepted models for studying economic conditions in power markets and simulating emissions of NOx and other pollutants."[213] "This was done to ensure full disclosure of possible environmental impacts even though the Commission disagrees that use of these assumptions is appropriate[,]"[214]and even though the Commission ultimately determined that it had no authority to take such environmental considerations into account under the FPA.[215] Rather, the Commission's EIS served to "add[] significantly to the understanding of the problem" that "should serve air regulators",[216] – which is consistent with NEPA's action-forcing goals. The Commission recognized, "What is critical is that environmental impacts of a proposed action be adequately identified and evaluated—an important component of this process is understanding the possible mitigation measures that are involved, including measures which may be beyond the jurisdiction of an agency to implement."[217]

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211 Order No. 888, 61 Fed. Reg. 21,540, at 21,670-21,689 (May 10, 1996).
212 *Id.*
213 *Id.* at 21,670.
214 *Id.*
215 *Id.* at 21,672, 21,683-21,687.
216 *Id.* at 21,673
217 *Id.* at 21,675

Given the Commission's demonstrated capability to prepare detailed environmental analysis of wide-ranging market regulations, the Commission can hardly now suggest it is unable to evaluate the likely market and environmental impacts of the proposed repeal of the PURPA regulations at issue.

b. The proposed rules eliminate important provisions encouraging QFs

Second, the NOPR's suggestion that the rules will still encourage QFs also misses the mark. As noted above, the question is whether the proposed rules – which remove the primary regulations supporting QF development – *may have* a significant impact on the human environment. The relevant question – for purposes of NEPA analysis – is not whether one could somehow conclude that the proposed rules could be considered to encourage QFs when compared to an outright legislative repeal of PURPA; rather, the question is whether the changes to the rules will reduce encouragement of QFs to the point where a perceptible environmental impact *may* result.

Quite obviously, the changes included in the newly proposed rules are very likely to have a significant adverse impact on QF development for all of the reasons explained above in these comments. The impact is likely to be particularly significant in regions without RPS laws or without organized wholesale markets. There is no evidence whatsoever to conclude that any QFs will continue to be developed without fixed-price contracts for energy and capacity. Even if one could accept the dubious proposition that the proposed regulations will still encourage QFs, that assumption does not overcome the undisputed fact that the new regulations will encourage QFs significantly *less* than the existing regulations. Further, there is a high probability that the reduced encouragement will result in less renewable and cogeneration facilities and loss of the resulting benefits of these facilities to the human environment.

In sum, the Commission should put the entire rulemaking on hold to allow for adequate time to conduct the required environmental analysis before re-evaluating whether to move forward with further consideration of the major elements of the NOPR.

III. CONCLUSION

For the reasons discussed above, the Commission should not adopt the NOPR's proposed rules.

Dated: December 3, 2019

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LIST OF ATTACHMENTS

Attachment 1 – Expert Report of Don C. Reading

Attachment 2 – Declaration of Carol Loughlin

Attachment 3 – Declaration of John Lowe

Attachment 4 – Declaration of Les Perkins

ATTACHMENT 1 – EXPERT REPORT OF DON C. READING

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Qualifying Facility Rates and Requirements	**Docket Nos. RM19-5**
Implementation Issues Under the Public Utility Regulatory Policies Act of 1978	**AD16-16-000**

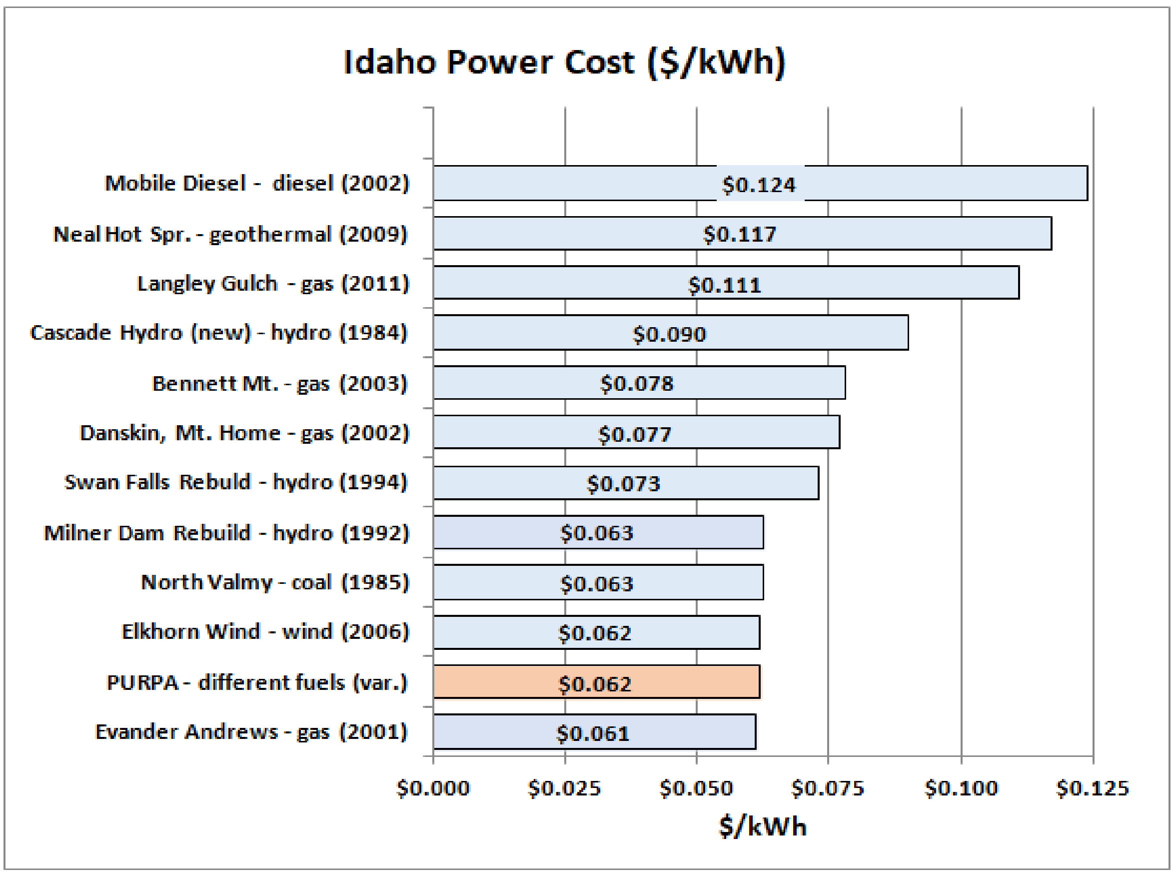
REPORT PREPARED BY DR. DON C. READING
BEN JOHNSON ASSOCIATES

COST COMPARISON BETWEEN IDAHO POWER COMPANY'S PURPA RESOURCES AND NON-PURPA RESOURCES
1984 – 2019

This report is intended to respond to testimony by Commissioner Kristine Raper of the Idaho Public Utilities Commission (Idaho PUC) at the Federal Energy Regulatory Commission's (the Commission or FERC) Technical Conference in Docket No. AD16-16 on June 29, 2019, which is relied upon in the Commission's Notice of Proposed Rulemaking (NOPR) in RM19-15, at Par. 64, Note 101, dated September 19, 2019. The NOPR quotes Commissioner Raper as follows: "Idaho Power demonstrated that the average cost for PURPA power since 2001 has exceed the Mid-Columbia (Mid-C) Index Price and is projected to continue to exceed the Mid-C price through 2032." However, the Mid-C index prices are not the appropriate comparison for Idaho Power Company's long-term PURPA prices because unlike the Mid-C index price, which is a day-ahead, short-term product, include an energy and capacity component. In response Commissioner Raper's comparison, this report presents a more appropriate comparison of the Idaho PUC-approved costs of Idaho Power Company's long-term non-PURPA facilities over time to the current average costs paid to PURPA facilities by Idaho Power.

A. Cost Comparison

As the data that compiled herein demonstrate, Idaho Power Company's experience with avoided cost resource acquisition has been an economic (and energy reliability) boon for ratepayers when compared to utility-owned resources and when compared to the ephemeral "market." In the three decades since PURPA was enacted in 1984, ten of the twelve resource acquisitions approved by the Idaho PUC were done so at rates *higher* than the combined cost of all PURPA resources. The following table indicates the resource, year of approval and levelized cost as determined at the time of approval for each non-PURPA resource approved by the Idaho PUC. Also shown are Idaho Power's average costs for all PURPA power delivered to the power company over the same time period:[1]



[1] A complete list of citations and supporting testimony/orders is attached as Exhibit 1.

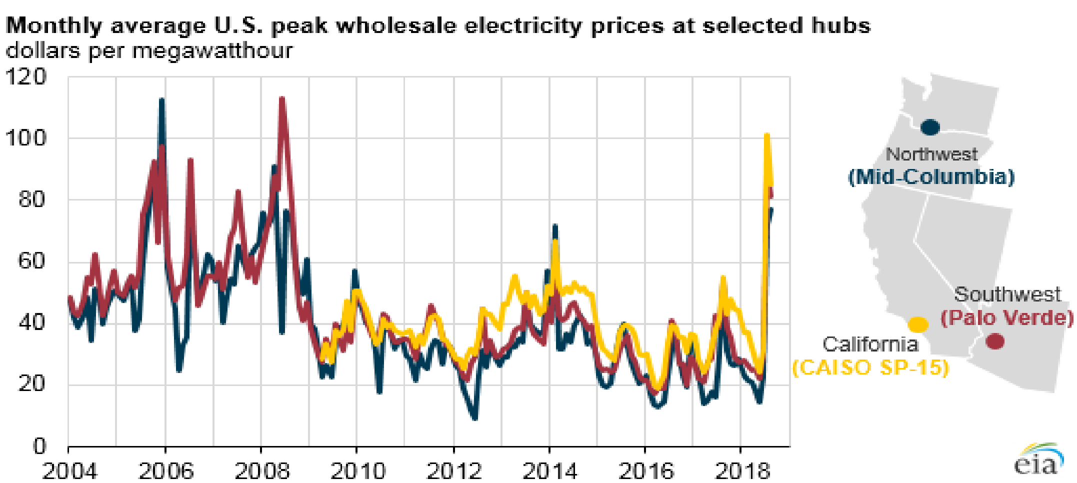
The indicated cost per kWh are in nominal dollars (i.e., not adjusted for inflation), which is a conservative assumption that favors the older non-PURPA resources over the 2018 costs of the PURPA resources.

It is important to note that the PURPA costs incurred by Idaho Power since 1984 are often reduced from the “full” avoided cost rates set forth in the contract due to several factors. For instance, PURPA projects, unlike Idaho Power-owned facilities, receive no compensation when they are not producing power. In addition, due to Idaho PUC-approved rate spread provisions in PURPA contracts, PURPA projects are paid at a discounted rate when they produce power during off-peak times (both diurnal and seasonal off-peak discounts are applied). Many PURPA projects also are compensated at a reduced rate if they fail to meet pre-determined production targets on a monthly basis – which discount can dramatically reduce the payments to intermittent resources such as hydroelectric and wind facilities. The net result is that the actual cost of PURPA resources are significantly lower than the originally approved cost for almost all of Idaho Power’s resources.

B. Reliance on Market Purchases

Another reason it is not reasonable to compare PURPA resources to Mid-C index prices is that typically the Idaho PUC does not allow utilities to rely heavily on the Mid-C short-term market to serve load. As displayed in the above table, the single most expensive resource approved by the Idaho PUC in the PURPA-era was acquisition of 25 mobile diesel generating units driven by volatility in the market during the Western Energy Crisis. In approving a levelized cost resource that is double the average cost of all PURPA resources, the Idaho PUC declared that it was a "prudent means of securing supply in a volatile market…"[2] This finding by the Idaho PUC directly contradicts comments[3] cited by FERC in observing that "QF rate[s], even when levelized, [are] well above market prices that likely would represent the purchasing electric utility's actual avoided energy costs at the time of delivery."[4] Indeed, the Idaho PUC admonished Idaho Power not to rely on the market for delivery of energy at the time of need. It dismissed reliance on the "volatile" market as 'imprudent' by explaining that, "We want Company management to *plan for power supply in advance* and take prudent steps to have adequate, reliability supply available."[5]

The energy crisis of 1999/2000 is just one example (albeit an extreme example) of the risks of reliance on the short-term market for firm power supplies. That event is not, however, anomalous. The volatility of the market over just the last decade and a half clearly supports the Idaho PUC's finding that reliance on the market at the time of delivery is not "prudent."



[6]

2 Idaho PUC Docket No. IPC-E-01-14, Order No. 28837 at p. 12.
3 Some of which were provided by a current Idaho PUC Commissioner.
4 NOPR at Par. 64.
5 Idaho PUC Docket No. IPC-E-01-14, Order No. 28837 at p. 12 (Emphasis provided).
6 Source: Energy Information Administration, available at https://www.eia.gov/todayinenergy/detail.php?id=37112

Exhibit 1

Idaho Power Resource Cost References

Neil Hot Springs
Order No. 31087, Docket No. IPC-E-0934.

Elkhorn Wind
Order No. 30259, Docket No. IPC-E-06-31.

Langley Gulch
Order No. 30892, Docket No. IPC-E-09-03.

Bennett Mt.
Order No. 29410, Docket No. IPC-E-03-12.

Evander Andrews
Order No. 30201, Docket No. IPC-E-06-09.

Mobile Generators
Order No. 28837, Docket No. IPC-E-01-14.

Mt. Home Generators (Danskin)
Order No. 28773, Docket No. IPC-E-01-12.

Swan Falls Hydro
Order No. 23520, Docket No. IPC-E-90-2.

Milner Dam Hydro
Order No. 23529, Docket No. IPC-E-90-8.

North Valmy Coal
Order No. 20610, Docket No. 1006.265.

Cascade Hydro
Order No. 20610, Docket No. 1006.265.

PURPA
Year end, 2018, Idaho Power PURPA report. On file at the IPUC.

Exhibit 2

Qualifications of Don Reading, PhD

Don Reading is Vice President and Consulting Economist for Ben Johnson Associates, a national economics consulting firm. The firm is based in Tallahassee, Florida, and Dr. Reading is a telecommuter who works in Boise, Idaho. He received his PhD from Utah State University and Master of Science from the University of Oregon. Dr. Reading has taught economics at Idaho State University, Middle Tennessee State University, Boise State University, College of Idaho, and the University of Hawaii-Hilo. From 1981 to 1986, he was economist and staff director at the Idaho Public Utilities Commission.

Dr. Reading has more than 45 years' experience in the field of economics. He has provided expert testimony concerning economic and regulatory issues on more than 50 occasions before utility regulatory commissions in Alaska, California, Colorado, the District of Columbia, Hawaii, Idaho, Montana, Nevada, North Carolina, North Dakota, Texas, Utah, Wyoming, Washington, and Manitoba Canada.

Dr. Reading has been active in PURPA related cases in North Carolina, Montana, Oregon, and Idaho. His testimony in these cases has focused on the modeling and calculation of avoided costs of the utilities, as well as the terms and conditions of PURPA contracts. Dr. Reading's areas of expertise in the field of electric power include demand forecasting, long-range planning, price elasticity, marginal and average cost pricing, production-simulation modeling, and econometric modeling.

VERIFICATION

I, Don C. Reading, having been duly sworn, and I declare under penalty of perjury of the laws of the United States that the contents of the foregoing Expert Report are true and correct to the best of my information and belief.

DATED this 2 day of December 2019.

Don C. Reading

Don C. Reading

SUBSRIBED AND SWORN to before me this 2 day of December 2019.

Grace Hansen

Notary Public for the State of Idaho

GRACE HANSEN
NOTARY PUBLIC - STATE OF IDAHO
COMMISSION NUMBER 20191536
MY COMMISSION EXPIRES 8-2-2025

Residing at 20191536

My Commission expires 8-2-2025

ATTACHMENT 2 – DECLARATION OF CAROL LOUGHLIN

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Qualifying Facilities Rates & Requirements	)	**Docket Nos.**
	)	
Implementation Issues Under the Public Utility Regulatory Policies Act of 1978	)	**RM19-15-000 &**
	)	
	)	**AD16-16-000**
	)	
	)	

DECLARATION OF CAROL LOUGHLIN

I, CAROL LOUGHLIN, under penalty of perjury, do declare as follows:

1. I make this declaration on the basis of personal knowledge and belief.

2. I understand that the Federal Energy Regulatory Commission has proposed a number of major changes to its rules implementing the Public Utility Regulatory Policies Act of 1978 (PURPA) and issued a Notice of Proposed Rulemaking ("NOPR") seeking comment on these proposals. The NOPR proposes, among other changes, to remove the obligation that states require electric utilities to offer to purchase the electrical energy of qualifying facilities at forecast, fixed energy prices, and instead would allow states to require only that capacity component of the prices be fixed while the energy component may be variable and calculated at the time of delivery of power based on short-term prices in the LMP or EIM markets. I further understand that certain other proposals could result in all but the smallest qualifying facilities, with capacity of 1 megawatt (MW) or less, being required to participate in organized wholesale energy markets, competitive solicitation for generation resources, or other markets to sell their electrical energy and capacity, as opposed to having the ability to sell such energy and capacity under a long-term power purchase

agreement to an electric utility under PURPA. My declaration is intended to respond to provide information on those topics based on my experience, information and belief.

3. I am currently a Senior Consultant in the Energy Solutions Group of Sapere Consulting, located in Tukwila, Washington. Prior to joining Sapere, I served as Vice President of Finance for Summit Power Group, an energy development company. For more than nine years, I have been involved with independent power producers and utilities in the Pacific Northwest, as well as other regions, in financing, developing, constructing and performing due diligence on electric generation projects. My responsibilities have included developing and reviewing pro forma financial statements, structuring financing transactions, marketing project generation and renewable energy certificates, responding to competitive solicitations for generation, complying with regulatory requirements, assisting with interconnection and transmission requests, and performing due diligence on proposed projects. Throughout my career, I have worked on a broad range of generation types and sizes, including solar, wind, natural gas, waste to energy, irrigation hydropower and run-of-river hydropower projects, with generation capacities ranging from 400 kilowatts to over 700 MW, as well as on diverse investment and financing structures for these projects, including institutional financing, private equity, construction and long-term debt, mezzanine financing, asset sales and acquisitions, and balance sheet financing.

4. It is unreasonable to suggest that variable spot market pricing is equivalent to a utility's avoided cost, as required by PURPA, because utilities have an obligation to procure electricity to serve load and they do not expose much of that obligation to market availability and price volatility, as evidenced by common utility procurement practices. Utilities do not make their own long-term planning, investment, and generation asset development decisions based on the lowest marginal cost of variable market resources, nor should independent power producers be forced to do

so given the statutory requirement to encourage competition in the electric industry and the statutory requirement that the QF be paid the rate that reflects the utility's avoided cost.

5. Small generators are already subject to complicated, time-consuming and expensive utility interconnection and contracting processes, permitting requirements and relatively high costs for small-quantity equipment orders, yet they are often able to match utility avoided costs due to low overhead and stringent cost control. Significantly, independent power producers, and not ratepayers, are also directly responsible for any cost overruns incurred during QF project development, construction and operations. The proposal to release utilities from the obligation to purchase power from small renewable energy projects that are between one and twenty megawatts in size, however, creates additional, potentially insurmountable, barriers to participation that further hinder competition.

6. Participating in wholesale markets requires sophistication, resources, and acquisition of services that are often not available to small projects and small developers or that are prohibitively expensive and burdensome to organizations with limited staffing and capital resources. Utilities provide such services in-house for their assets, whether large or small, at the expense of ratepayers. Typically, a seller in the wholesale market would be required to:

- Register and maintain market accounts;
- Post substantial security deposits to obtain transmission to wholesale trading hubs;
- Request and purchase firm point-to-point transmission to the trading hub;
- Locate an agent willing to provide time-consuming and detail-intensive scheduling, trading and settlement services – in my experience, these services are difficult for small projects to obtain at any price and are very expensive when available;

- Contract for balancing services, for which payment can be due even when a project is not generating energy; and
- Implement expensive technology to provide real-time generation data 24 hours per day, 7 days a week.

7. Generation projects that participate in wholesale markets transactions are typically required by transmission providers to schedule power deliveries in 1 MW increments. It would likely be uneconomic for many small projects to participate in the wholesale electricity market due to revenue losses from downward rounding of significant portions of their generation for scheduling purposes.

8. Availability and affordability of capital is crucial to electricity market competition[1] and has been instrumental in driving wholesale market price reductions over the past several years. Exposure to short-term variable wholesale market pricing via a floating-price PPA or in merchant wholesale market transactions would drastically limit competition by impairing or eliminating independent generators' access to project financing, the most common source of capital for renewable energy projects.[2] The basic premise of project finance is that lenders provide project development capital based solely upon an individual project's risks and expected future revenue. The proposed reliance upon volatile short-term market pricing for most, or all, of a project's expected revenue will not provide lenders comfort that future revenue can be reasonably expected to cover financing costs. Many small renewable energy projects currently face financing barriers including high interest rates and substantial maintenance reserves and debt service collateral

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[1] BjarneSteffen. *The Importance of Project Finance for Renewable Energy Projects*. Energy Economics, Volume 69, January 2018, Pages 280-294. Accessed at: https://doi.org/10.1016/j.eneco.2017.11.006
[2] Ibid.

requirements[3]. The introduction of significant repayment risk would either severely limit a project's borrowing capacity (and therefore viability and ability to compete on price) by dramatically increasing debt service coverage requirements and debt service reserves, or it could eliminate access to standard project finance structures altogether. The NOPR proposal to remove the obligation that states require electric utilities to offer to purchase the electrical energy of qualifying facilities at forecast, fixed energy prices can therefore be reasonably expected to impair competition in the wholesale electricity market.

9. The NOPR proposes that hedges be used to ensure reliable revenue and remedy the obvious financing challenges associated with floating rate pricing. Typical hedging structures and synthetic PPAs are contracts that trade actual (floating) wholesale electricity prices for payment of a predetermined fixed price. Such products might hypothetically allow a QF to pay a premium for a counterparty to bear the risk of electricity price volatility, but many hedge providers decline to work with small projects because they are not cost effective and have higher risk profiles. Due diligence and transaction expenses that would be incurred to implement small hedge contracts, including attorney, independent engineer, and insurance advisor fees, often exceed the hedge provider's anticipated revenue from a small hedge contract, while operating risks are perceived to be higher because the impact of any equipment failure would have a much greater impact on a small project's revenue than it would on a larger project's revenue. For example, an unplanned outage of one turbine on a 10-turbine wind farm would reduce the project's output by 10%, but the same unplanned outage at a 100-turbine farm would reduce the project's total output by only 1%.

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[3] Michael Mendelsohn and John Harper. National Renewable Energy Laboratory. *1603 Treasury Grant Expiration: Industry Insight on Financing and Market Implications*. Accessed at: https://www.nrel.gov/docs/fy12osti/53720.pdf

10. For projects that qualify to purchase a market hedge, the requirement to do so reduces project profitability and disincentivizes investment in renewable energy generation. The additional expense is also anti-competitive as utility-owned projects with balance-sheet financing do not incur similar hedging costs. Many states, in fact, have rate adjustment mechanisms that protect utility returns from market and fuel price volatility, effectively transferring these risks to ratepayers.

11. Participating in wholesale markets increases credit risk which adds additional challenges to obtaining cost-effective, competitive financing terms. Purchasing counterparties in merchant transactions are often power marketers, rather than investment grade load-serving utilities providing long-term contracts, therefore the NOPR, as proposed, would expose independent power projects to higher counterparty credit risks that would need to be mitigated through guarantees, letters of credit, or some other mechanism to obtain financing. This could eliminate many potential project developers, such as irrigation districts or municipalities, that do not have the financial wherewithal to place substantial amounts of long-term financial security.

12. FERC is also proposing to require QFs to demonstrate "commercial viability" and show a "financial commitment to construct" before a utility is required to sign a PPA with the project. This is inconsistent with market practices and, while it might be hypothetically achievable by large developers with the ability to balance-sheet finance projects, it discriminates against small developers, who must rely on project financing to construct a facility. Renewable energy projects are typically capital-intensive and require the developer to raise large amounts of funding well in advance of the start of operations. As noted above, project finance is not typically provided unless there is a projected revenue stream that can be secured for purposes of ensuring repayment of the loans. It would demonstrate questionable exercise of a lender's fiduciary responsibilities to commit to financing a project without an executed power sales contract, or an assured path to obtaining one, and so is very

unlikely to occur. This NOPR proposal would not serve the goals of increasing competition because utility-owned projects with balance-sheet financing are not subject to the same requirements.

13. Granting utility buyers the right to terminate a QF contract in the event of a regulatory change to the purchase obligation would create revenue uncertainty that would further reduce incentives to invest in and provide financing for capital-intensive renewable energy QF projects. Utility-owned projects are not subject to similar risk therefore the proposed termination right is not consistent with encouraging competition in the electricity industry.

14. Small QFs often provide benefits that large, utility-owned generation resources do not. Studies have established the value of diverse fuel sources[4], dispersed generation[5], and development of local fuel sources[6]. Utility resource procurement in the Northwest tends to favor large projects and a limited number of well-established technologies. In many cases this has resulted in utilities importing significant amounts of energy or fuel into the region while exporting ratepayer dollars. QFs, on the other hand, are better equipped to assume the risks of exploring potentially valuable new technologies, such as biofuels or wave energy technology, but it is only practical to do so with a path to a low-risk, fixed price PPA. Unlike large utility-owned projects, small QFs can often be sited close to load on under-utilized sections of the electrical grid, which can reduce line losses and interconnection-related upgrades while increasing grid resiliency. Utility contracts with QFs can also reduce the export of ratepayer dollars while encouraging local and regional development and providing direct and indirect economic benefits in the form of jobs, income and property taxes, and

[4] A. John Armstrong, Esq. & Dr. Jan Hamrin. *The Renewable Energy Policy Manual*. U.S. Export Council for Renewable Energy. Accessed at: http://www.oas.org/dsd/publications/unit/oea79e/begin.htm#Contents

[5] EPA. *Assessing the Electricity System Benefits of Energy Efficiency and Renewable Energy.* Accessed at: https://www.epa.gov/sites/production/files/2018-07/documents/mbg_2-3_electricitysystembenefits.pdf Union of Concerned Scientists. December 20, 2017. *Benefits of Renewable Energy Use.*

[6] National Renewable Energy Laboratory. *Dollars from Sense The Economic Benefits of Renewable Energy.* (DOE/GO-10097-261). September 1997. Accessed at: https://www.nrel.gov/docs/legosti/fy97/20505.pdf

related economic multiplier effects.[7] Reducing the ability of current and prospective QFs to compete in the electricity market would likely also reduce innovative generation and technology development in the U.S.

15. Despite these benefits, small projects have been precluded or discouraged from participating in competitive solicitations for new generation in most recent Northwest utility energy solicitations. For example, in the last three years, RFPs issued by Northwest utilities have provided the following guidance:

- PacifiCorp's 2019R Utah RFP criteria included a minimum project size of 20 MW.
- The Avista Request for Proposals for Renewable Energy, dated June 6, 2018, required respondents to have a minimum net annual output of 5 aMW alternating current.
- Portland General Electric's 2018 Request For Proposals for 100 MW of Renewables restricted project size to a minimum 10 MW.
- Puget Sound Energy 2018 All Resources RFP, June 8, 2018 encouraged qualified facilities of 5 MW or less to sell power pursuant to its electric tariff Schedule 91 (offered to Qualifying Facilities pursuant to its obligations under Washington Administrative Code 480-107-095).
- PacifiCorp's 2017R RFP included a minimum wind project size of 10 MW.
- PacifiCorp's 2017S RFP limited eligibility to solar projects over 10 MW.

16. The changes proposed by the NOPR will not only inhibit the development of new domestic energy resources but, without the right to sell power to the incumbent utility, a large

[7] Arjun Krishnaswami, Elisheva Mittelman. *Clean Energy Sweeps Across Rural America*. NRDC NOVEMBER 2018 R-18-10-A.

amount of operational MWs are at risk of leaving the Northwest market if no renewal option exists when their current QF PPAs expire.

17. I have attached hereto as Attachment A an overview of most major wind and solar generation resources acquired by IOUs in the Pacific Northwest over the last 15 years. The table does not include IOU procurement from small projects, QFs, or all types of generation. As the column labeled "RFP" demonstrates, much of this new generation was acquired directly by the incumbent investor-owned utilities without a competitive solicitation process. Given that the Northwest still operates under a traditional vertically integrated utility model, this means that IPPs had no opportunity to bid on or construct these facilities.

18. Further, as the column labeled "Utility Owned" in Attachment A demonstrates, the vast majority of wind and solar generation in the Northwest is owned directly by the incumbent investor-owned utilities. Only a handful of projects have been procured under a competitive bidding process in which an independent power producer won the right to construct, own and operate the generation (signified by a "Yes" in the "RFP" column and a "No" in the "Utility Owned" column). The remaining projects that are not directly owned by utilities were acquired from independent power producers without an RFP or other formal process intended to ensure market access for IPPs.

19. Finally, Attachment B to this declaration shows the percent of utility-owned versus IPP-owned generation (as measured in annual megawatt hours produced) in Northwest states, including EIA data for all fuel types in Table 1. Table 2 of Attachment B shows the percent of Northwest states' annual electricity production sourced from wind and solar generators in 2018 (as measured in annual megawatt hours produced). The data is derived from the same Energy

Information Administration ("EIA") databases[8] as are cited by FERC in the NOPR. Generation by wind and solar resources remains a small percentage of total annual electricity production in the Northwest and, as is readily apparent, the vast majority of all energy generation in these states is owned by utilities. The outlier is Montana, but this number is likely an anomaly arising from Montana's experiment with retail electric deregulation, in which it required divestiture of generation assets, then permitted those assets to be re-acquired by the incumbent IOUs. In this process, a significant portion of the very large Colstrip generating station came to be owned by an independent power producer that was spun off from PPL. But this was the result of legislative mandates rather than effective competition.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

DATED this 2 day of December, 2019.

By: Carol Loughlin

Carol Loughlin

[8] EIA. 1990-2018 Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923). Accessed at: https://www.eia.gov/electricity/data/state/

ATTACHMENT A
OVERVIEW OF MAJOR RENEWABLE RESOURCE ACQUISTIONS BY NORTHWEST INVESTOR-OWNED UTILITIES[9]

Year	RFP	Utility	Location	Project	MW	Utility Owned	Resource
2019	No	Rocky Mountain Power/PacifiCorp	Utah	Panguitch, Utah	0.65/1	Yes	Solar/Battery
2019	Yes	Avista	Washington	Rattlesnake Flat Wind	144	No	Wind
2019	Yes	Puget Sound Energy	Washington	Lund Hill Solar	150	No	Solar
2019	No	Rocky Mountain Power/PacifiCorp	Utah	Cove Mountain Solar 2	122	No	Solar
2018	No	PacifiCorp	Utah	Cove Mountain Solar	58	No	Solar
2018	Yes	Avista	Washington	Adams-Neilson Solar Farm	28	Yes	Solar
2018	Yes	Portland General Electric	Oregon	Wheatland	300/50/30	Yes	Wind/Solar/Battery
2017	Yes	Puget Sound Energy	Washington	Skookumchuck Wind	137	No	Wind
2017	Yes	PacifiCorp	Wyoming	TB Flats I & II	500	Yes	Wind
2017	Yes	PacifiCorp	Wyoming	Cedar Springs	200	Yes	Wind
2017	Yes	PacifiCorp	Wyoming	Ekola Flats	250	Yes	Wind
2017	Yes	PacifiCorp	Wyoming	Uinta	161	Yes	Wind
2017 - 2019	No	PacifiCorp	Wyoming	Glenrock I	99	Yes	Wind
2017 - 2019	No	PacifiCorp	Wyoming	Glenrock III	39	Yes	Wind
2017 - 2019	No	PacifiCorp	Wyoming	Rolling Hills	99	Yes	Wind
2017 - 2019	No	PacifiCorp	Wyoming	Seven Mile Hill I	99	Yes	Wind
2017 - 2019	No	PacifiCorp	Wyoming	Seven Mile Hill II	19.5	Yes	Wind
2017 - 2019	No	PacifiCorp	Wyoming	High Plains	99	Yes	Wind
2017 - 2019	No	PacifiCorp	Wyoming	McFadden Ridge	28.5	Yes	Wind
2017 - 2019	No	PacifiCorp	Wyoming	Dunlap	111	Yes	Wind
2017 - 2019	No	PacifiCorp	Oregon	Leaning Juniper	100.5	Yes	Wind
2017 - 2019	No	PacifiCorp	Washington	Marengo I	140.4	Yes	Wind
2017 - 2019	No	PacifiCorp	Washington	Marengo II	70.2	Yes	Wind
2017 - 2019	No	PacifiCorp	Washington	Goodnoe Hills	94	Yes	Wind
2017 - 2019	Yes	PacifiCorp	Wyoming	Ekola Flats	250	Yes	Wind
2017 - 2019	Yes	PacifiCorp	Wyoming	TB Flats I & II	500	Yes	Wind
2015	No	Avista	Washington	Community Solar	0.425	Yes	Solar
2013	No	Portland General Electric	Washington	Tucannon River Wind	267	Yes	Wind
2010	No	Portland General Electric	Oregon	Rock Creek Wind	400	Yes (project was terminated)	Wind
2009	Yes	PacifiCorp	Wyoming	Dunlap Wind 1	111	Yes	Wind
2008	Yes	PacifiCorp	Wyoming	Top of the World Wind	200	No	Wind
2009	No	PacifiCorp	Wyoming	Glenrock III	39	Yes	Wind
2009	No	PacifiCorp	Wyoming	Rolling Hills	99	Yes	Wind
2009	No	PacifiCorp	Wyoming	High Plains	99	Yes	Wind
2009	No	PacifiCorp	Wyoming	McFadden Ridge	28.5	Yes	Wind
2009	No	PacifiCorp	Wyoming	Campbell Hill-Three Buttes	99	No	Wind
2008	No	PacifiCorp	Washington	Marengo II	70.2	Yes	Wind
2008	No	PacifiCorp	Wyoming	Glenrock I	99	Yes	Wind
2008	No	PacifiCorp	Wyoming	Seven Mile Hill I	99	Yes	Wind
2008	No	PacifiCorp	Wyoming	Seven Mile Hill II	19.5	Yes	Wind
2008	No	PacifiCorp	Washington	Goodnoe Hills	94	Yes	Wind
2007 - 2010	No	Portland General Electric	Washington	Bigelow Canyon I, II & III	450	Yes	Wind
2007	Yes	Puget Sound Energy, PGE	Oregon	Klondike Wind	50	No	Wind
2007	No	PacifiCorp	Washington	Marengo I	140.4	Yes	Wind
2006	No	PacifiCorp	Oregon	Leaning Juniper	100.5	Yes	Wind
2009	Yes	NorthWestern Energy	Montana	Spion Kop	40	Yes	Wind
2009	No	Puget Sound Energy	Washington	Wild Horse Wind Expansion	44	Yes	Wind
2009	No	Puget Sound Energy	Washington	Lower Snake River I	172	Yes	Wind
2008	No	Puget Sound Energy	Washington	Lower Snake River I	171	Yes	Wind
2007	Yes	Idaho Power	Oregon	Elkhorn Wind	100.7	No	Wind
2006	No	Puget Sound Energy	Washington	Wild Horse Solar	0.5	Yes	Solar
2005	Yes	Puget Sound Energy, PGE	Oregon	Klondike Wind	75	No	Wind
2005	Yes	NorthWestern Energy	Montana	Judith Gap	135	No	Wind
2004	Yes	Puget Sound Energy	Washington	Wild Horse Wind	229	Yes	Wind
2003	Yes	Puget Sound Energy	Washington	Hopkins Ridge	150	Yes	Wind

[9] The table contains a sample of IOU procurement of wind and solar resources only. It does not include all utility procurement, procurement from QFs, or small projects or all resource types.

ATTACHMENT B

PERCENT OF UTILITY-OWNED GENERATION OF ALL RESOURCE TYPES IN 2018 (AS MEASURED IN ANNUAL MWh PRODUCED)

PER ENERGY INFORMATION ADMINISTRATION DATA[10]

Table 1. IPP and Electric Utility 2018 Electricity Generation (MWh), by State

State	IPP	Electric Utility
AK	1%	89%
ID	31%	66%
MT	55%	43%
OR	18%	73%
UT	10%	89%
WA	11%	87%
WY	6%	91%

PERCENT OF WIND AND SOLAR ELECTRICITY GENERATION IN 2018 IN NORTHWEST STATES (AS MEASURED IN ANNUAL MWh PRODUCED)

PER ENERGY INFORMATION ADMINISTRATION DATA[11]

Table 2. Percent of Total Electricity Generation (MWh) Sourced from Wind and Solar Resources, by State

State	Wind % of Total 2018 Electricity Generation	Solar % of Total 2018 Electricity 2018 Generation
AK	2.48%	0.0000%
ID	14.61%	3.0594%
MT	7.57%	0.1206%
OR	11.62%	0.8917%
UT	2.02%	5.6474%
WA	6.77%	0.0015%
WY	8.80%	0.0036%

[10] EIA. 1990-2018 Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923). Accessed at: https://www.eia.gov/electricity/data/state/
[11] Ibid.

ATTACHMENT 3 – DECLARATION OF JOHN LOWE

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Qualifying Facilities Rates & Requirements	)	**Docket Nos.**
	)	
Implementation Issues Under the Public Utility Regulatory Policies Act of 1978	)	**RM19-15-000 &**
	)	**AD16-16-000**
	)	
	)	

DECLARATION OF JOHN R. LOWE

I, JOHN R. LOWE, under penalty of perjury, do declare as follows:

1. I make this declaration on the basis of personal knowledge, experience and belief.

2. I understand that the Federal Energy Regulatory Commission has proposed several changes to its rules implementing the Public Utility Regulatory Policies Act of 1978 ("PURPA") and sought comment on a number of changes to the implementation of PURPA including the impact of removing the requirement that states require electric utilities to offer to purchase the electrical energy of qualifying facilities at forecast, fixed energy prices. Instead the proposed rules would allow states to require only that the capacity component of the prices be fixed while the energy component may be variable and calculated at the time of delivery of power. I further understand that another proposed rule change would likely result in all but the smallest qualifying facilities, with capacity of 1 megawatt ("MW") or less, being required to participate in organized wholesale energy markets, competitive solicitation for generation resources, or other markets to sell their electrical energy and capacity. This is opposed to them currently selling such energy and capacity under a long-term power purchase agreement to an

electric utility under PURPA. My declaration is intended to respond to and provide information on those topics based on my experience, information and belief.

3. In 1975, I graduated from Oregon State University with a Bachelor of Science degree. From 1975 to 2006, I was employed by PacifiCorp. Over twenty-five of that 31-year period, my responsibilities were primarily related to PacifiCorp's power purchase contracting and policies under the PURPA throughout the utility's multi-state service territory, which includes Washington, Oregon, California, Idaho, Wyoming, and Utah, and even Montana prior to PacifiCorp selling that portion of its service territory. My responsibilities included all contractual matters arising under PURPA and supervision of other matters related to both power purchases and interconnections. In that capacity, I was involved in scores of contract negotiations and interconnections, helped develop new contract concepts, terms and language, and became familiar with terminology commonly used in the electric utility industry in utility tariffs and written power purchase agreements for purchases from qualifying facilities ("QF"). Since founding the Renewable Energy Coalition ("REC") in 2009, I have been directing and managing the activities of REC as well as providing consulting services to individual members of REC related to all interfaces with their electric utility with particular focus on power purchases and interconnections and the terms, conditions, and agreements required for such key relationships.

4. REC is an unincorporated trade association that was established in 2009 and is comprised of approximately forty members who own and operate over fifty mostly non-intermittent small renewable energy generation QFs in Oregon, Idaho, Montana, Washington, Utah, and Wyoming. Several types of entities are members of the REC, including irrigation districts, water districts, corporations, and individuals. The majority of REC's members own

and operate small hydroelectric projects in all of the states mentioned above. REC has members operating or developing projects for most technology types including solar, geothermal, waste and biomass.

5. REC's overarching goal is to ensure fair and reasonable contracting processes, contract terms and conditions for projects of all size and type, and reasonable access to avoided cost rates for all projects. This includes eligibility or application of standard contracts and published non-negotiated avoided cost prices. The vast majority of the REC's members own and operate existing QFs, therefore a critical component of our goal and purpose is to ensure that FERC recognizes and accounts for numerous unique circumstances and benefits of existing projects and does not diminish the opportunity for these projects to continue operating. This concern arises continuously at the various state regulatory venues since most changes to PURPA's implementation commonly is initiated and viewed through the lens of potential new project development. While most of REC's members are existing projects that have been operating and selling to utilities for decades, some of REC's members are attempting to construct new renewable energy projects.

6. Based on my experience, I believe FERC's proposals will harm the ability for new renewable energy generators to be constructed, and for existing renewable energy generators to continue to operate. I am very concerned about the negative impact that FERC's proposals will have on new renewable energy generators; however, my declaration will focus on the impacts on existing renewable energy generators because FERC's proposals and, I expect, most of the rulemaking comments, ignore that the proposals will result in shutting down operating projects. Therefore, my declaration focuses on existing projects.

7. Existing QFs are those projects that are already operating and are generally selling power to the interconnected utility. Many of these projects have been operating since the mid 1980s.

8. The reason for PURPA has not changed. The barriers that REC's QF members faced when they initially began operations still exist today, and these barriers now act against continued operation. These distributed, non-utility owned resources provide significant capacity, locational, environmental and other benefits to utilities and ratepayers. They were mostly built in the early 1980s following the enactment of PURPA, and many were built to last 100 years. Creating an environment now, only 40 years into the useful life of these projects, that would result in existing projects shutting down would be a colossal waste of resources. Existing QFs still need PURPA to create a level playing field that supports the continued operation of non-utility-owned generation.

9. Existing projects face some unique challenges. Existing projects must enter into a replacement contract when their current contract expires. This means there is no flexibility as to the time at which such a new contract would start. A new contract almost always starts during a contract term that includes an initial period of utility resource sufficiency, and the new contract term may be shorter than the then-current resource sufficiency period established through each utility's Integrated Resource Plan ("IRP"). In other words, if a project is not allowed to replace its contract in advance of expiration, and the resource sufficiency is at least three years long, then the new contract will not include a period of resource deficiency based prices. Historically, resource sufficiency is four or more years long, and today's resource sufficiency periods for Northwest utilities are sometimes more than twice that number of years.

10. Most existing projects have been operating for years, and may require major replacement and/or upgrading of their equipment, conveyance structures, and other facilities including interconnections. New interconnection agreements are usually required. There can be significant time and costs involved in meeting the then-current interconnection requirements.

11. In my experience, existing projects often require financing and long-term planning needs very similar to those of proposed projects. Since many of REC's 50-plus projects are existing projects, these matters are of significant importance to REC. Many REC members have already gone through replacement of the original power purchase agreement. Usually the expiration of a power purchase agreement is the appropriate time to plan, finance and implement major updating of generation equipment and project infrastructure. This could include additions and improvements as well as updating of equipment to then-current standards or upgrades to improve efficiency and environmental enhancements. These changes are often significant in terms of financial and contract processes and timing that must align with key elements, including contract length and FERC's proposals will impact the opportunity to make necessary and mutually desirable project improvements. In the case of hydroelectric projects, this would mean that short contract terms would result in the loss of efficiency and water conservation improvement opportunities and even the potential loss of all existing benefits the project contributes, including the loss of competitive clean green power.

12. Since PURPA was enacted, there has been little change in the markets in which REC's members operate. There is no organized competitive wholesale market in this region, utility procurements are not truly competitive, and the utilities still control access to the grid and own the majority of the generation. The small QF projects, like REC's members, still face barriers to entry and barriers to continue operating, including the need to finance capital

investments, utility hostility toward non-utility owned generation, and utility control over the interconnection process.

13. Even if there was a market for small projects to sell their power, negotiating contracts can be time consuming and costly, especially for small and existing QFs, and could be expected to be very burdensome. Small existing facilities rarely have the option of selling their power to other entities, and typically only have the choice of continuing to sell their power to their interconnected utility or shutting down. Also, since existing QFs, especially small hydro projects that are Federal Energy Regulatory Commission licensed or exempted, have little locational flexibility, these QFs have fewer or only one potential purchasing utility. These projects were planned for and can be expected to continually operate and deliver power to their interconnected utility, provided the price warrants continued operation.

14. Existing projects often provide utilities, ratepayers and the environment with unique benefits. For example, existing QFs are usually included as a part of the long-term resource portfolio in utilities' IRPs. Most baseload projects especially hydro are very long-term projects and have virtually no locational flexibility. In addition, these projects operate under FERC licenses or exemptions which come with numerous obligations regarding project operation or face severe costs to cease operation. These QFs are often built to last 100 years. They have provided capacity value to the utilities and ratepayers during the past 40 years and will continue to provide this value over the remainder of their useful lives, which justifies paying existing QFs a capacity payment at all times and not just during resource deficiency. It is important and sensible to recognize the capacity value they provide when they renew their contracts regardless of the utilities' resource position by continuing to pay for capacity. The Idaho Public Utilities Commission requires capacity payments to existing QFs during the

resource sufficiency period because they provide capacity value to the utilities during all years and are expected to continue to sell power to the utilities.

15. Existing distributed, non-utility-owned resources also provide locational benefits because they are more likely to be located closer to utility load than utility-owned resources, often large projects from out of state or that need to be transmitted long distances. QFs, rather, tend to be located in-state and not only help the utility avoid building or buying other generating resources, but also help avoid transmission resources.

16. Additionally, existing QFs provide clean energy and environmental benefits, which many utilities and states have prioritized with 100% "carbon free" goals, renewable portfolio standards, or other initiatives. From a global perspective, it makes no sense to prioritize construction of new clean energy projects while shutting down these existing QF projects that have many more years to their useful lives. FERC's proposal that QFs 1 MW or larger no longer have the right to long-term fixed prices will likely result in many existing projects shutting down their operations or at a minimum not facilitate efficiency, water conservation or environmental improvements to their operations. This includes many community quasi-municipal based projects like those owned and operated by irrigation districts, water control districts and domestic water entities.

17. Existing QFs still need PURPA to provide a level playing field with the utilities. It is far more difficult in time, money and expertise for QFs to negotiate and complete contracts over the state-established eligibility threshold for standard avoided cost rates (also referred to as "published rates"). All states that I work in allow smaller QFs to obtain published rates instead of negotiating rates or having their rates determined by a utility-controlled computer model. In

some cases, this includes the application of a standard form contract minimizing the need to negotiate contract terms.

18. There are a number of important reasons for treating smaller projects differently, some which include developer sophistication, transaction costs, economies of scale, and the inability to economically access alternative markets. It is important to recognize the unique difficulties facing smaller projects, and allowing smaller projects to sell power at a published rate helps mitigate some of these difficulties. Just the complexities of moving their power purchase beyond standard contract and published price application will discourage many from continuing operation. And winning RFPs is highly improbable given the requirements of most RFPs regarding minimum size or technology type, or even ownership options.

19. Negotiating contracts can be costly in terms of upfront transactional costs and very problematic in terms of timing. Small QFs do not typically have the experience or knowledge to be able to understand a wide morass of moving parts in the PURPA world and have virtually no control over the process, results or timing. Therefore, at a minimum, there will be little guarantee of success unless such project owners seek and pay for experts with the skills to navigate the processes and negotiation of contracts. Just the negotiating of a QF contract with a utility can take a great deal of time, create numerous risks and be very expensive. Completion of an agreement is therefore quite challenging and risky given the many factors important to the negotiation that can or often do change during an extended process. All of these transactional costs, risks and limited opportunities can make smaller projects uneconomic.

20. Small projects also do not have the options available to larger projects. For example, large scale resources developed by utilities or large independent power producers benefit from being sized so that the dollar-per-kilowatt investment required to build the plant is

less than for a much smaller sized QF of the same basic technology. Similarly, it is my understanding that the typical short-term power sale trades in the Pacific Northwest electricity market are generally for larger blocks of power, and small QFs cannot effectively participate in this market.

21. The problems described above impact both new and existing projects. Existing and operating QFs provide utilities and their ratepayers with significant benefits. For example, utilities rely upon their continued operation to provide needed capacity benefits. Existing projects also benefit their local communities and economies, which will be lost if they cannot enter into new longer-term and fixed price contracts. For hydroelectric projects this will likely translate to the inability to make improvements to increase efficiency and water conservation or for them to cease operations.

22. Many existing projects require long-term agreements for system improvement projects, planning and financing. This is especially true for QFs that are part of large water conveyance systems, such as irrigation districts. There are other reasons why longer-term agreements are necessary, one of which is the avoidance of market based or lower energy prices during periods of resource sufficiency. A term limit on existing projects is problematic in terms of continuous renewal of contracts and exposes the QFs much lower prices (total value) than would result from a single long-term contract.

23. Shutting down existing projects will have harmful impacts on the environment. For example, most new hydro resources, as well as the expansion and continued operation of existing projects need to be certified as "low impact." This results in environmental benefits like improved ecological flow regimes, water quality protection, upstream fish passage, demonstrate fish passage and protection, watershed and shoreline protection, and threatened and endangered

species protection. With FERC's proposed changes, some of these benefits will not occur in certain areas or cease to be available.

24. In sum, PURPA is still needed. REC's existing QF members still face barriers to compete with Northwest utilities now that they faced when PURPA was first enacted. These distributed, non-utility owned resources provide significant capacity, locational, environmental and other benefits to utilities and ratepayers, and will continue to do so. The proposed rulemaking in its current form, will allow these barriers to persist and will result in existing projects shutting down.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

DATED this 2ND day of DECEMBER, 2019.

By: ______________________

John R. Lowe

ATTACHMENT 4 – DECLARATION OF LES PERKINS

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Qualifying Facilities Rates & Requirements)	**Docket Nos.**
)	
Implementation Issues Under the Public Utility Regulatory Policies Act of 1978)	**RM19-15-000 &**
)	**AD16-16-000**
)	
)	

DECLARATION OF LES PERKINS

I, LES PERKINS, under penalty of perjury, do declare as follows:

1. I make this declaration on the basis of personal knowledge and belief.

2. I understand that the Federal Energy Regulatory Commission has proposed several changes to the its rules implementing the Public Utility Regulatory Policies Act of 1978 (PURPA) and sought comment on the impact of removing the requirement that states require electric utilities to offer to purchase the electrical energy of qualifying facilities at forecast, fixed energy prices, and instead allowing states to require only that capacity component of the prices be fixed while the energy component may be variable and calculated at the time of delivery of power. I further understand that certain other proposals could result in all but the smallest qualifying facilities, with capacity of 1 megawatt (MW) or less, being required to participate in organized wholesale energy markets, competitive solicitation for generation resources, or other markets to sell their electrical energy and capacity, as opposed to selling such energy and capacity under a long-term power purchase agreement to an electric utility under PURPA. My declaration is intended to respond to provide information on those topics based on my experience, information and belief.

3. I am the general manager of Farmers Irrigation District, located in Hood River, Oregon. I also currently serve (and have served for 19 years) as a county commissioner for the Hood River County, Oregon. In addition, I am currently serving on the executive board of the Community Renewable Energy Association ("CREA"), am a board member of Oregon Water Resources Congress ("OWRC") and serve on the Hydropower subcommittee of OWRC, am an executive committee member of the Hood River Energy Council, and Farmers Irrigation District is a member of the Renewable Energy Coalition ("REC").

4. With respect to CREA, the organization was established in 2007 as an Oregon Revised Statute 190 intergovernmental association. Members include counties, irrigation districts, councils of government, project developers, for-profit businesses and non-profit organizations. CREA works with local communities, counties, state and federal agencies, Congress, the Oregon Public Utilities Commission and the Oregon Legislature to advocate for improved policies that support development of more community renewable energy in Oregon. Our members and staff help educate policy-makers and interested communities on steps toward progress for renewable energy development. The organization and its staff also work to provide technical expertise for developers, landowners and counties where projects are under consideration. Additionally, CREA is an active participant in proceedings before the Oregon Public Utility Commission affecting renewable energy development, especially proceedings implementing PURPA.

5. Among its goals, CREA's work is intended to promote the environmental, economic, and local generation benefits of renewable energy development, especially opportunities for locally owned renewable energy development. CREA's work is intended to provide local economic benefits for its member counties, in the form of increased tax base from

direct taxation on renewable energy facilities and increased economic activity associated with construction, operation and revenue from such local renewable energy facilities. Local renewable energy facilities, when owned by local governments or special districts, provide revenue which is used to pay for infrastructure improvements. Local renewable energy facilities also provide distributed generation resources that can be configured to provide power to critical infrastructure in the event of a grid outage.

6. REC was established in 2009 and is comprised of almost forty members who own and operate over fifty small renewable energy generation qualifying facilities ("QFs") in Oregon, Idaho, Montana, Washington, Utah, and Wyoming. Several types of entities are members of the REC, including irrigation districts, water districts, corporations, and individuals. Most of REC's members are existing projects that have been operating and selling to utilities for numerous years; however, many REC members are attempting to construct new renewable energy projects. The majority of REC's members are small hydroelectric projects.

7. Farmers Irrigation District, FID, a nonprofit government agency founded in 1874, is located in Hood River, Oregon, and is a member of CREA. FID is located in the beautiful, culturally rich Columbia River Gorge. Water is provided to 5,900 acres of land and just under 2,000 customers, both residential and agricultural. Hood River County is known for its beautiful orchards and depends heavily on their production of pears, apples, wine grapes, berries, and cherries for economic vitality. The county produces more winter pears than any county in the United States and the economic footprint of agriculture in Hood River County was estimated at $306 million in 2009.

8. FID's mission is to support this economy by promoting ecologically, socially, and financially sustainable agriculture by providing energy and irrigation service for the common good.

9. FID has nine primary water diversions, all of which are run-of-the river (no dams on free-flowing rivers and creeks) and protected by state of the art head works and our patented fish friendly Farmers Screens approved by National Oceanic and Atmospheric Administration ("NOAA") fisheries. Having received state and federal agency approval for The Farmers Screen, we patented the technology and now license it to the Farmers Conservation Alliance with the condition that profits be used for the united benefit of fish, farms, families, and environment. The screen investments have dramatically stabilized and increased our hydro production while saving farmers hundreds of thousands of dollars per year. These technologies and concepts extend to many other water districts in the state and beyond with 50 Farmers Screen installations in 8 states. We are proud of our century-long efforts in innovative efficiencies and environmental protection and plan on continuing to be leaders in irrigation management by aggressively raising the bar in sustainable agriculture, power production, fish screening standards, and water conservation measures into the foreseeable future.

10. Since implementation of hydropower production capabilities in the mid-eighties, FID has invested over $50 million in capital improvement projects that create and maintain jobs, keep agriculture competitive in a global market, and support the community and environment. None of this would be possible without dependable, fair, long-term power-sales agreements. Continuation of power-sales agreements that are dependable, fair, and long term in nature are absolutely critical to our operational budgets, commitments to agriculture, long-term debt service owed to private, state and federal entities, necessary investments in critical water conveyance

infrastructure, and the entire fabric of community and commerce that have come to depend on us as a public entity.

11. FID owns, operates, and maintains a hydroelectric facility for the generation of electric power, including interconnection facilities, located in Hood River Oregon (within the region covered by the Western Electricity Coordinating Council) with a Facility Capacity Rating of 4,400 kilowatts ("kW"). FID sells its net output directly to PacifiCorp under the Oregon Public Utility Commission's standard contract offered to qualifying facilities under 10,000 kW in capacity. The current power purchase agreement contains long-term fixed-prices for energy and capacity for a 15-year period, which was the length of fixed-price term required by the Oregon Public Utility Commission at the time of contract execution. FID retains ownership of the associated, unbundled renewable energy credits under the power purchase agreement, and sells those renewable energy credits to various other public and private entities under RPS mandate or voluntarily concerned about carbon footprint and climate change.

12. Generating electricity from local water systems has been a critical component of FID's daily operations since the mid-eighties. FID has one Gilkes Turgo impulse style turbine generator with a 2,600 kW capacity, and one 1,800 kW Pelton style turbine. FID power plants are modern and utilize sophisticated equipment and technology with new digital controls, new high-pressure units, new main unit breakers, new exciters, and a new transformer installed within the last three years. A brand-new turbine and generator set were installed in FID powerhouse 2 in 2015, replacing inefficient and costly-to-maintain Francis style turbines. FID generators produce an approximate average of 23,000 megawatt hours ("MWh") per year. With our many capital improvement projects, infrastructure rehabilitation efforts, innovation, and water conservation measures implemented over time, our production is stable. Our system has also been recognized

as low impact and has been certified through the Low Impact Hydropower Institute. This certification requires third-party verification of our practices and impact on our watershed.

13. FID's current contract term of fixed prices became effective on January 1, 2011 and shall terminate 15 years later on December 31, 2025. Contract prices are paid for on-peak and off-peak production. This contract replaced the original contract of 25 years which expired on December 31, 2010. The current contract applies limited levelization to help FID in minimizing severe cash flows mainly caused by resource sufficiency year avoided cost pricing under PacifiCorp's Schedule 37 at the time of contract execution and the non-payment for capacity during such sufficiency years through 2013, which without levelization would have resulted in a much lower price in 2011 through 2013 of the current contract. FID also has a separate interconnection agreement that was executed November 24, 2010.

14. A critical component of Oregon's implementation of PURPA for FID has been the ability to obtain a long-term fixed price and a standard contract that is not subject to renegotiation every few years. The primary reason is to avoid being subject to negotiation of replacement power purchase agreements that are not based upon known published prices and being required to negotiate the prices and contract terms. FID does not have the expertise to negotiate such prices and terms without significant third-party assistance and expense. Further, I would expect that such agreements could not be reasonably finalized without significant time delays, potential controversy with the purchasing utility, and risks associated with fluctuating prices and terms.

15. Although the FID may be relatively large in terms of end-users of water and other delivered resources, our primary business is not the development of energy producing projects. Our focus is the continued operation of the water systems needed to serve our communities and

maintaining the safe and reliable nature of our current hydroelectric projects. We are not large, sophisticated energy developers, nor can we afford to waste or justify taxpayer dollars on non-expeditious process in which we have very little expertise.

16. I believe the fixed-price period for energy and capacity payments of 15 years is necessary to facilitate the long-term planning of the hydropower operations in context with other planning associated with the water system. This includes financing needed to make system improvements, repairs, and meet or exceed environmental requirements. Our existing projects are part of a large complex of integrated facilities that primarily deliver water to citizens and businesses. In order to financially plan, engineer, build and operate these systems, including the hydro projects, it is necessary to incorporate long-term financing. Even with a 15-year power contract term, it is absolutely necessary to have long-term financing in place which exceeds such term. Shorter term contracts or contracts without fixed prices for energy and capacity would make long-term planning challenging and risky for FID. Short-term contracts and variable pricing would also handicap our ability to provide and maintain safe infrastructure and reliable water supply to citizens, including but not limited to large and small agri-business.

17. Additionally, in my experience in the industry, capital expenditures do not cease once a small hydropower project and related water delivery systems are initially constructed. In most cases, capital improvement projects are going on continuously. Responsible districts and water suppliers typically have a substantial annual ongoing capital improvement and safety program that relies on long-term debt. District water systems are expensive to maintain, and large piping and other capital improvement projects are critical to supporting the needs of a growing society dependent on water and agriculture. Capital improvements rely on long-term debt financing and our ability to meet debt service. Long-term financing necessary to maintain

safe and aging infrastructure is not only critical to saving and protecting lives, but simply the responsible thing to do.

18. Price stability and certainty for current and potential new power purchase agreements is of utmost importance. Pricing stability and certainty are essential for reliable water service. For districts with existing contracts, reliability on power purchase agreement pricing is commensurate with water being available out of the faucet at your home, or not. Frequent renegotiations of power sale arrangements would harm our ability to make long-term plans that rely upon stable prices.

19. In addition to generating power, the electrical generation output of FID's projects also produce grid benefits and non-energy environmental, economic and social benefits. The avoided cost rate in FID's existing power purchase agreement does not consider any of the secondary societal and grid benefits produced by small, distributed renewable energy projects. A market does exist for some of these separate non-energy benefits through "green tags," "tradable renewable certificates," and "renewable energy certificates," which can be sold on the market to third parties or the utilities themselves. Purchasers of these non-energy attributes often wish to enter into long-term contracts in excess of 10 years. Based on FID's experience and my understanding of the industry, I believe that an irrigation district can procure greater sales opportunities and higher and more stable prices if it can enter into longer term contracts for the sale of such renewable energy certificates. However, an irrigation district may not be able to agree to sell the non-energy benefits under a long-term contract if it only has a short-term assurance of the sale of electrical output to the electric utility. Without generation of the electrical energy, there would be no production of renewable energy certificates to sell.

Therefore, a short -term commitment for power sales can cause significant limits to a QF's ability to receive revenue from the sale of the non-energy attributes.

20. In my opinion, allowing sufficient and fair fixed-price rates over a reasonably long time period to support and plan our projects with base production revenue is absolutely paramount. For the reasons explained above, I do not believe that FID or most other similarly situated irrigation districts could successfully participate in organized wholesale energy markets, utility's competitive solicitation for generation resources, or other markets to sell their electrical energy and capacity, as opposed to selling such energy and capacity under a long-term power purchase agreement to an electric utility under PURPA. Likewise, attempting to finance our operations with financial hedging products is not an activity I believe FID could successfully implement. Lacking the in-house expertise to engage in such activities, I believe that if FERC were to require QFs to do so to sell their electrical energy, FID's ability to continue sale of its output after expiration of its existing power purchase agreement would be compromised and the benefits of such sales discussed above would be lost. The loss of existing generating resources, especially small, distributed resources, would be a loss of necessary capacity that has served small communities around the country for decades. Many irrigation districts, domestic water districts, and wastewater districts around the country rely on the revenue from QF contracts to service debt incurred to improve critical infrastructure. Without PURPA and the stipulation of acceptable contract lengths, project size limits, and pricing, these projects will be shuttered, and new projects will not be developed. PURPA provides the only real access to market for small independent power producers in markets where investor owned utilities control supply, transmission, and distribution and have guaranteed returns on investment combined with guaranteed markets.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

DATED this 2nd day of December, 2019.

By: ______________________

Les Perkins