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Effects of Tax Reform on the Renewable Energy Sector

By Gerald M. Feige and Azeka J. Abramoff

On December 22, 2017, the tax reform bill known as the Tax Cuts and Jobs Act (H.R. 1) (the "Tax Reform Act") was signed into law. Prior to its enactment, the renewable energy industry was deeply concerned about proposals in the House of Representatives (the "House Bill") and the Senate (the "Senate Bill") that, if enacted, would have had significant adverse effects on the utility of both the renewable energy investment tax credit (ITC) and energy production tax credit (PTC).

Most of these unfavorable proposals were withdrawn, and the Tax Reform Act largely preserves the benefits of the ITCs and PTCs. The final version of the Tax Reform Act also partially alleviated the negative effect that the so-called base erosion anti-abuse tax (the BEAT) would have had on the ITC and PTC, but only on a temporary basis, creating significant uncertainty for certain taxpayers considering tax equity investments. This article describes the (i) general business provisions relevant to the renewable energy sector and (ii) renewable energy credit specific provisions.

Business Tax Reform Effects on the Renewable Energy Sector

Corporate Tax Reform

The corporate tax rate was reduced from 35 percent to 21 percent. Unlike many other provisions of the Tax Reform Act, the new corporate tax rate does not expire. However, going forward, net operating losses (NOLs) can only be used to offset 80 percent of taxable income. Furthermore, such NOLs cannot be carried back but can be carried forward indefinitely (the prior law allowed NOLs to be carried back two years or carried forward 20 years). The new rules only apply to NOLs generated in taxable years beginning after December 31, 2017. As a result, NOLs generated before that time can continue to be used to offset 100 percent of taxable income and may be carried back.

The Tax Reform Act also provides that (i) contributions to a corporation in aid of construction or any other contribution as a customer or potential customer and (ii) any contribution by a government entity or civic group (other than contributions made as a shareholder) are taxable income to the corporation. Thus, utilities and other corporations receiving state assistance in the form of contributions must treat such contributions as taxable income.

Deduction for Pass-Through Income

The Tax Reform Act provides a new deduction for individuals, estates and trusts equal to 20 percent of the taxpayer's "qualified business income," which results in an effective top tax rate of 29.6 percent (based on a new maximum individual rate of 37 percent). The deduction does not apply to investment-related income.

For taxpayers with income over a certain threshold, (i) the deduction phases out for income from so-called specified services businesses in which the principal asset is the reputation or skill of the employees or owners, and (ii) is limited to 50 percent of the taxpayer's allocation of the W-2 wages paid by the business, or (iii) the sum of 25 percent of the W-2 wages plus 2.5 percent of the unadjusted basis in certain tangible, depreciable property used in a trade or business for the production of qualified business income. The phase-out begins for taxpayers with taxable income over $315,000 (for married taxpayers filing jointly) or $157,500 (for individuals) and phases out completely for taxpayers with an additional $100,000 of income (for married taxpayers filing jointly) or $50,000 (for individuals).

Non-corporate taxpayers owning interests in partnerships engaged in operations in the renewable energy sector may be eligible for the 20 percent deduction on allocations of partnership income.

Bonus Depreciation

The rules expand and extend bonus depreciation. Under the new rules, "qualified property" acquired and placed in service after September 27, 2017 is eligible for 100 percent depreciation in the year such property is placed in service. The 100 percent bonus depreciation begins to phase down in 2023 for most qualified property (2024 for certain long-production-period property) and phases down 20 percent per year until it is eliminated entirely in 2027 (2028 for certain long-production-period property). In the taxpayer's first taxable year ending after September 27, 2017, the taxpayer can elect to apply a 50 percent bonus depreciation rate instead of 100 percent.

"Qualified property" eligible for 100 percent bonus depreciation includes depreciable property with a recovery period of 20 years or less as well as property with a recovery period of at least 10 years if such property has an estimated production period of at least one year and a cost of at least $1 million. The new rule also expands the definition of "qualified property" to include used property that is newly acquired by the taxpayer. However, it excludes property used primarily in "regulated public utilities businesses." A regulated public utilities business includes trades or businesses that furnish or sell (1) electrical energy, water or sewage disposal services, (2) gas or steam through a local distribution system, or (3) transportation of gas or steam by pipeline, if the rates for the furnishing or sale have been established or approved by the United States or any state government, political subdivision, or any agency or commission thereof.

Interest Expense Deduction Limitation

The Tax Reform Act imposes a new limitation on businesses' interest expense deductions. Under the new rules, net interest expense deductions are limited to 30 percent of "adjusted taxable income." "Adjusted taxable income" means the taxpayer's taxable income, computed without regard to any NOL carryovers, business interest income or expense, the new deduction for pass-through income (described above) or, solely for taxable years beginning before 2022, depreciation, amortization or depletion. Thus, net interest deductions are essentially limited to 30 percent of EBITDA before 2022 and 30 percent of EBIT thereafter. Given the high deductions anticipated under the new 100 percent bonus depreciation rules, computing the 30 percent interest deduction limitation on EBITDA rather than EBIT is expected to provide short-term relief for certain highly leveraged, capital-intensive businesses. Disallowed interest deductions can be carried forward indefinitely (although they may be subject to limitation if the business's ownership changes).

The interest deduction limitation only applies to taxpayers with average annual gross receipts for the prior three-year period that do not exceed $25 million. Furthermore, the interest deduction limitation only covers "business interest," which is defined to exclude regulated public utilities businesses (as defined above). Thus, although public utilities are not eligible for the increased 100 percent bonus depreciation, they are not subject to the 30 percent interest deduction limitation. In the case of taxpayers that are partnerships, the limitation is applied at the partnership level. Business interest disallowed at the partnership level is allocated to the partners, who may deduct such interest in future years, but only against excess taxable income allocated to the partner from the partnership.

Repeal of the Domestic Production Activities Deduction

The Tax Reform Act repeals the deduction for domestic production activities. The domestic production activities deduction previously allowed taxpayers to deduct nine percent of the lesser of their qualified production activities income or taxable income. The deduction included income attributable to qualifying production property that was manufactured, produced, grown or extracted in the United States; electricity, natural gas or potable water produced in the United States; and the construction of real property in the United States. The deduction was limited to 50 percent of the W-2 wages paid by the taxpayer allocable to such domestic production businesses.

Treatment of Renewable Energy Credits under the Tax Reform Act

Retention of PTCs and ITCs

Early tax reform proposals caused significant concern for the energy sector. The House Bill would have removed an inflation adjustment for PTCs, significantly reducing their future value. It also would have modified the phase-out schedule for ITCs and eliminated the permanent ITC for solar energy investment. Furthermore, the House Bill purported to “clarify” the determination of when a project begins construction, which would have curtailed a five percent investment safe harbor provided by the Internal Revenue Service. These changes were dropped by the Senate Bill. The final version of the Tax Reform Act retained the existing ITC and PTC regimes, without change.

Elimination of the Corporate AMT

The Senate Bill also initially contained provisions that could have had a chilling effect on investments in renewable energy products though. For one, the Senate Bill retained the corporate AMT, which would have affected many more corporate taxpayers given the lower overall corporate tax rates. Furthermore, since the ITC did not offset the corporate AMT, and the use of PTCs to offset the corporate AMT was subject to significant limitations, retention of the corporate AMT would have significantly reduced the utility of these credits. The Tax Reform Act eliminates this problem by repealing the corporate AMT.

The Tax Reform Act Adds a New, Potentially Significant Limitation on PTCs and ITCs

More significantly, the Senate Bill included the BEAT, a new minimum tax designed to apply to U.S. corporations that make significant deductible payments to related foreign persons. The BEAT applies to domestic corporations that are members of an affiliated group with average gross receipts of over $500 million over the prior three-year period and deductible payments to related foreign parties representing over three percent of its total annual deductions (two percent in the case of corporations that are members of a group that includes a bank or a registered securities dealer).

If the BEAT applies, the U.S. corporation’s tax is increased by the excess of:

(i) 10 percent of its “modified taxable income” (i.e., the corporation’s taxable income after adding back its deductible payments to foreign related parties); over

(ii) its adjusted U.S. income tax liability (the “Income Tax Offset”).

The 10 percent rate is reduced to five percent for 2018, but increased to 12.5% beginning in 2026. Banks and registered securities dealers add one percent for all years.

Under the Senate Bill, a U.S. corporation's Income Tax Offset was equal to its regular tax liability, reduced by its tax credits, other than the research and development credit, but including ITCs and PTCs. As a result, if a corporation was subject to the BEAT, the BEAT liability would claw back the benefit of ITCs and PTCs. Because a number of financial institutions that could be affected by the BEAT are also investors in renewable energy projects, the BEAT would have eroded the value of tax equity investments and created significant uncertainty for taxpayers considering such investments.

The Tax Reform Act revised the BEAT calculation in a manner designed to protect most, but not all, of the benefit of ITCs and PTCs against the BEAT. Under the Tax Reform Act, like the Senate Bill, the Income Tax Offset is equal to a U.S. corporation's regular tax liability, reduced by its credits. However, the Tax Reform Act modifies the calculation to add back 80 percent of the lesser of (i) the corporation's available renewable energy ITCs and PTCs or (ii) the corporation's BEAT liability (determined without regard to this calculation). By increasing Income Tax Offset, the taxpayer's BEAT liability is correspondingly reduced. As a result, up to 80 percent of the taxpayer's renewable energy ITCs and PTCs directly reduce its BEAT liability.

For example, suppose a U.S. corporation has taxable income of $100, after accounting for $200 of deductible payments to foreign related parties, and renewable energy ITCs and PTCs of $5. The corporation's regular tax liability on $100 of income is $21. After taking into account its ITCs and PTCs, the corporation's income tax is reduced to $16. Under the Senate Bill, 10 percent of the corporation's $300 of modified taxable income (taxable income of $100, adding back deductible payments to foreign related parties of $200) is $30. The BEAT increases the corporation's tax by $14 ($30 minus the Income Tax Offset of $16), bringing the corporation's total tax to $30 ($16 of income tax plus $14 of BEAT).

Had the corporation not been eligible for the $5 of renewable energy ITCs and PTCs, its total tax would still be $30, since its income tax would be $21 and its BEAT ($30 minus the Income Tax Offset of $21) would be $9. Thus, in these facts, under the Senate Bill, the BEAT would have completely eliminated the benefits of the renewable energy ITCs and PTCs.

Under the Tax Reform Act, however, the benefits of the renewable energy ITCs and PTCs are partially preserved. Using the facts in the example above, the U.S. corporation's regular tax liability on its $100 of income is $21. After taking into account its $5 of renewable energy ITCs and PTCs, its income tax is reduced to $16. However, the Income Tax Offset is increased to add back 80 percent of the lesser of (i) the corporation's $5 credit or (ii) its $14 BEAT (determined without regard to this provision). Thus, the Income Tax Offset is increased by $4 (80% of $5), bringing its total Income Tax Offset to $20 ($16 plus $4). As a result, under the Tax Reform

Act, the corporation's BEAT is only $10 ($30 less the income tax offset of $20), bringing the corporation's total tax to $26 ($16 of income tax plus $10 of BEAT). The add-back of up to 80 percent of the renewable energy ITCs and PTCs prevented the BEAT from clawing back most of their value.

The 80 percent add-back for renewable energy ITCs and PTCs sunsets in 2026, however. As a result, taxpayer models assessing the value of these credits must analyze their exposure to the BEAT and the likelihood that Congress will extend the protections for renewable energy ITCs and PTCs beyond 2026. Accordingly, renewable energy investors face some uncertainty regarding the future value of tax equity investments, particularly in the case of PTCs that are available over a 10-year period.

House Energy Subcommittee Considers Bill to Eliminate Federal Authorization to Export or Import Natural Gas—Including LNG

By Donna J. Bobbish

On December 11, 2017, Representative Bill Johnson (R-OH) introduced a bill "to repeal restrictions on the export and import of natural gas" (H.R. 4605). H.R. 4605, the "Unlocking Our Domestic LNG Potential Act," would amend Section 3 of the Natural Gas Act (NGA),[1] which requires prior authorization for the export of natural gas from the U.S., the import of natural gas into the U.S. and the siting, construction, expansion or operation of facilities to import or export natural gas, including liquefied natural gas (LNG). Although it would retain the requirement under Section 3 to obtain prior authorization for facilities to import or export natural gas, H.R. 4605 would eliminate the requirement to obtain prior authorization to import or export the commodity natural gas.

Authorizations required under Section 3 of the NGA are apportioned between the Federal Energy Regulatory Commission (FERC) and the Department of Energy's Office of Fossil Energy (DOE/FE).

Under Section 3(a) of the Natural Gas Act, FERC authorizes the siting, construction and operation of facilities to import or export natural gas, including pipelines crossing the U.S. border and on-shore LNG terminals, upon a finding that the siting, construction and operation of such facilities is not inconsistent with the public interest.

Section 3(a) of the NGA also requires prior approval from DOE/FE for a person to import any natural gas to the U.S. from a foreign country or export any natural gas from the U.S. to a foreign country. With respect to the basis upon which DOE/FE decides whether to authorize such imports and exports, Section 3 of the NGA distinguishes between countries with which the U.S. has a Free Trade Agreement (FTA) that require national

1 15 U.S.C. § 717b.

treatment for trade in natural gas ("FTA Countries")[2] and Non-FTA Countries. Section 3(c) of the NGA deems natural gas imports from and exports to FTA Countries to be in the public interest and requires DOE/FE to authorize applications for such imports and exports without modification or delay. Under Section 3(a) of the NGA, imports of natural gas from and exports of natural gas to Non-FTA Countries are authorized if DOE/FE finds that such exports are not inconsistent with the public interest.

Since the early 2000s, U.S. natural gas production has increased, primarily due to increased shale gas production through hydraulic fracturing or "fracking." According to EIA, in 2017, the U.S. was a net exporter of natural gas on an annual basis for the first time in 60 years.[3]

Since 2012, DOE/FE has authorized the large-scale export of 21.35 billion cubic feet per day of natural gas in the form of LNG.[4] These authorizations typically include, among others, conditions to prevent U.S.-produced LNG from reaching countries with which such trade is prohibited; for example, a requirement that any agreement or other contract for the sale or transfer of LNG exported contain a commitment by the customer or purchaser "to cause a report to be provided to [the exporter] that identifies the country of destination (or countries) into which the exported LNG or natural gas was actually delivered and/or received for end use, and to include in any resale contract for such LNG the necessary conditions to insure that the authorized exporter is made aware of all such actual destination countries."

H.R. 4605 would amend Section 3 of the NGA to delete Sections 3(a)-(c). If amended, Section 3 of the NGA would only require prior FERC authorization to site, construct and operate facilities for natural gas imports and exports. It would no longer require commodity export and import authorization. H.R. 4605 also would add a new subsection to provide that nothing in Section 3 limits the authority of the president to prohibit imports or exports of natural gas under the U.S. Constitution or enumerated laws that impose sanctions on a foreign person or foreign government, including a foreign government that is designated a state sponsor of terrorism.

H.R. 4605 was referred to the House Committee on Energy and Commerce on December 11, 2017, and to the Subcommittee on Energy on December 15.

2 "National treatment" for trade means treating an imported good the same as a locally produced good once it enters a market. Not all countries that have an FTA with the United States require national treatment for trade in natural gas. According to DOE/FE, as of October 31, 2012, FTA Countries include Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, Republic of Korea and Singapore.

3 Energy Information Administration, *Short-Term Energy Outlook* (Jan. 9, 2018).

4 *See Lake Charles Exports, LLC*, DOE/FE Order No. 4011, FE Docket No. 16-110-LNG, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Lake Charles Terminal in Lake Charles, Louisiana, to Free Trade Agreement and Non-Free Trade Agreement Nations (June 29, 2017) at p. 42.

On January 19, the Subcommittee on Energy held a legislative hearing to consider H.R. 4605.

In his opening remarks, Rep. Greg Walden (R-OR), chairman of the Committee on Energy, argued that the changes to the NGA in H.R. 4605 “would help create more open, transparent, and competitive markets for natural gas, encourage more production in the U.S., create thousands of jobs, and spur further economic development. . . .” by removing “unnecessary restrictions” on natural gas exports. On the other hand, Rep. Frank Pallone (D-NJ), the ranking member of the Committee on Energy, expressed concern that “unrestricted export policy included in [H.R. 4605] could significantly impact domestic natural gas prices and adversely affect American consumers and manufacturers.” He further argued that “we must have a mechanism for the Federal Government to know the source and destination of gas imports and exports, something that is crucial for our national security.”

In his testimony, Steven Winberg, DOE Assistant Secretary for Fossil Energy, testified that H.R. 4605 “would remove DOE’s authority in regulating natural gas trade for the United States,” and that the Trump administration has not taken a position on the bill. He further explained that while DOE has, to date, authorized about 21 billion cubic feet (Bcf) per day of LNG exports, currently only about 3 Bcf per day is being exported from the Sabine Pass LNG terminal in Louisiana, and studies previously conducted by DOE suggest that the U.S. could export up to 28 Bcf per day without negative economic effects or detriment to the price of gas in the U.S. Winberg agreed with Rep. Jerry McNerney (D-CA) that the DOE export authorization process is valuable for ensuring that U.S. LNG exports are strengthening the energy sector of U.S. allies and not benefitting those who seek to harm the country.

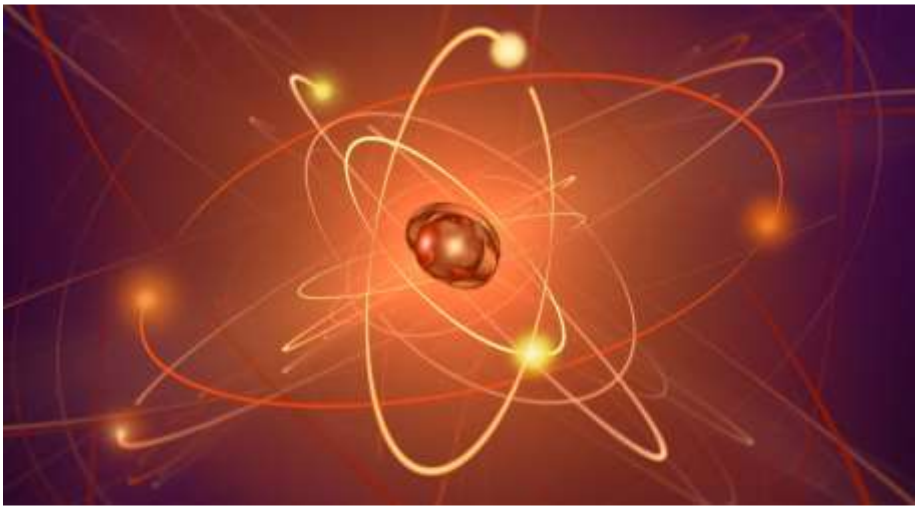
In his testimony, FERC General Counsel James Danly confirmed that H.R. 4605 would not change FERC’s authority to approve facilities for the import and export of natural gas, but pointed out that an “unintended consequence” of deleting current Section 3(a) of the NGA was to remove the “public interest standard” under which FERC exercises its authority.

Paul N. Cicio, President of Industrial Energy Consumers of America, which represents manufacturing companies, testified in opposition to H.R. 4605, arguing that the bill is “anti-consumer by removing the [NGA’s] public interest determination that was wisely put in place by Congress to ensure that LNG export volumes do not damage the economy and jobs.” He further argued that while “a reasoned volume of LNG exports is good for the economy, … excessive LNG exports will damage manufacturing competitiveness long-term and threaten capital investment that is now occurring due to low natural gas prices and trillions of dollars of existing manufacturing assets.” Cicio further argued that LNG volumes already approved by DOE/FE are equal to 71 percent of U.S. natural gas demand in

2016 and that exporting 71 percent of U.S. demand "cannot possibly be in the public interest."

Charlie Riedl, Executive Director of the Center for Liquefied Natural Gas, which represents LNG producers, shippers, terminal operator and developers, testified in support of H.R. 4605. He argued that "there is a limited window of opportunity for the U.S. to realize its potential as a major international gas supplier," "we know that exports are in the national interest" and that "further DOE approval of export applications is unnecessary." Riedl also argued that "[u]ntil recently, it has been unnecessarily difficult for DOE to grant Non-FTA export permits," and that DOE/FE's review procedure has changed several times, creating a "history of regulatory uncertainty." He pointed out that, to date, only one LNG export facility, Sabine Pass, is operating in the lower 48 states and has exported LNG to over 25 countries.

To date, no other action with respect to H.R. 4605 has been scheduled.



Latent Effects Compensation Under the Price-Anderson Act: Current Cases

By Chelsea Gunter

The Price-Anderson Act[5] provides omnibus insurance coverage for NRC licensees (operators) and related contractors in the event of a nuclear incident involving a nuclear power plant in the United States or shipment of nuclear material between licensees. The Act, passed into law in 1957, was the first national nuclear liability regime established among the world's countries operating nuclear power plants, and has undergone significant extension and revision since its initial codification. One unique aspect of the Act is that it provides, in the event that liability for any given accident is likely to be exceeded, for the development of compensation plans for payment of claims that arise as a result of latent injuries.[6] Other nuclear liability instruments, such as the Convention on Third Party Liability in the Field of Nuclear Energy (Paris Convention), the Convention on Supplementary Compensation (CSC), and the Protocol to Amend the Vienna Convention on Civil Liability for Nuclear Damage (Vienna Convention), ultimately extinguish rights for personal injury compensation; the Paris Convention and CSC after 10 years, and the Vienna Convention after thirty, with some exceptions.[7]

Harm that is caused by exposure to radiation may not manifest itself for decades after exposure.[8] Provisions in the Price-Anderson Act to establish compensation funds for injury later proven to result from ionizing radiation exposure may be seen then as a proactive approach that corresponds to reality for potential harms suffered from a nuclear incident. However, policymakers, scientists and industry have long acknowledged that latent

5 42 U.S.C. § 2210

6 42 U.S.C. § 2210(i)(2)(C)

7 See Article 8(a), Article 9(1) and Article 8(1), respectively.

8 For a discussion of this issue in nuclear liability regimes, see Patrick Reyners, Developments in International Conventions on Nuclear Third Party Liability, IAEA, http://www.iaea.org/inis/collection/NCLCollectionStore/_Public/31/051/31051429.pdf

injuries from radiation exposure are very hard to prove. In 1990, the Presidential Commission on Catastrophic Nuclear Accidents, established by the 1988 amendments to the Price-Anderson Act, devoted considerable time to this issue in its Report to Congress. The Commission noted that, because the Price-Anderson Act requires that the tort law of the state where a nuclear incident occurred must provide the substantive rules for compensating claims, establishing that radiation exposure was the "but-for" cause of a claim for cancer or any other harm is virtually impossible without a lawsuit:

> "Under the present system, latent illness claims are less likely to be resolved without dispute for the very reason that cancers that could be radiogenic also have other causes, and the precise cause cannot be isolated in a given case. Settlements are less likely when causation is so uncertain and also because there are no accepted alternative institutions for dispute resolution."[9]

What the Commission highlights in this passage, and develops throughout its report, is the possibility for latent effects compensation under the Price-Anderson Act to be both over- and under-inclusive of claims, and for the potential cost to utilities of litigation to determine which claims are legitimate. While at the time of a nuclear incident the federal court assigned to consolidate claims may authorize payment of legal costs, it is unclear whether that court should prepare a plan that provides compensation both for future latent injury claims and the expense of litigating those claims. Adding additional costs to future compensation claims may put unnecessary pressure on licensees that must still pay annual primary insurance premiums and insurance premiums into a retrospective pool of funds, particularly if such claims are never brought, and are subject to any uncertainty regarding Congress's obligation to appropriate future funds following the exhaustion of available insurance indemnities, or the ultimate Presidential approval of compensation plans.

For these reasons, the Commission recommended that the Price-Anderson Act take an "intermediate" approach to latent illness claims that involves creating a registry of potential claimants at the time of the accident, providing medical monitoring and offering settlements to individuals who develop an illness that have some causal connection with exposure.[10] This would limit the potential exposure of licensees and industry to costs associated with litigating claims and compensating claimants, while also meeting Congress's intent to ensure that latent illnesses are compensated. While the Commission's recommendations were reported to Congress in 1990, no changes in line with its recommendations were made to the Price-

[9] Appendix D, Latent Illness Claims under Present Law, http://www.state.nv.us/nucwaste/news/rpccna/pcrcna14.htm

[10] *Id.*

Anderson Act. Moreover, two recent cases demonstrate that even these recommendations may be insufficient to achieve the Price-Anderson's dual goals to both compensate claims and provide some certainty to industry.

McMunn v. Babcock & Wilcox Power Generation Group

On August 23, 2017, the Third Circuit decided an appeal in favor of defendants by plaintiffs McMunn, et al, of a District Court decision granting summary judgement to Babcock & Wilcox Power Generation Group.[11] The plaintiffs, more than 70 individuals, had been diagnosed with various forms of cancer, which they attributed to radiation effluent from the Apollo, Pennsylvania nuclear fuel fabrication facility operated by NUMEC, later purchased by Babcock & Wilcox. In its decision, the Court affirmed the District Court's ruling that there was no dispute as to material fact, noting that, although stacks at the Apollo facility may have exceeded permissible effluent levels provided in NUMEC's license, samples taken at the roof edge of the Apollo facility were below maximum permissible concentrations determined by federal standards.

The Court devoted a section of its decision to explaining causation issues in latent effects claims—entitled "The Science of Cancer." While acknowledging that "any increase in radiation exposure above zero is believed to increase the probability of carcinogenesis," the Court stated with regard to particular claims that "in a case like this one, the factfinder will always have to use ex-post data to ascertain whether any radiation—let alone any particular radioactive exposure—disrupted the cell in the past." Without completion of bioassays at the time of an incident, medical monitoring, or even, in fact, the occurrence of a single incident to which to point, potential radiation exposure in excess of permissible limits would require recreating both a physiological and atmospheric historical record—a virtually insurmountable task that, in this instance, nonetheless required litigating to the Circuit Court level before dismissal.

The *McMunn* decision represents neither an optimal outcome for industry or for claimants, both of whom dedicated time and money to the dispute. However, it is not clear that the intermediate approach recommended by the Presidential Commission on Catastrophic Nuclear Accidents would have brought the parties any closer, as the plaintiffs were not able to point to a single nuclear incident that would have been responsible for their exposure, although the Apollo facility violated the terms of its operating license.

Dailey v. Bridgeton Landfill, LLC.

The District Court for the Eastern District of Missouri is set to schedule oral arguments this year in the case of *Dailey v. Bridgeton Landfill, LLC* after denying defendants' motion to dismiss the case in October 2017. Plaintiffs,

[11] McMunn v. Babcock & Wilcox Power Generation Group, Inc., No. 15-3506 (3d Cir. 2017).

Michael and Robin Dailey, claim property damage for radioactive contamination stemming from West Lake Landfill, the final repository for mill tailings generated as part of the Manhattan Project by defendant Mallinckrodt LLC from 1942–1957. The plaintiffs' claim, ultimately brought under the Price-Anderson Act, is against both the owners and operators of the landfill, which is not an NRC licensee, and radioactive waste generators and disposers.

While the plaintiffs claim that samples from their home, adjacent to the landfill, demonstrate the presence of highly elevated radioactive particles, the District Court nonetheless dismissed their request for medical monitoring as not a plausible claim for relief because the Daileys did not otherwise allege current physical injury. In light of the decision in *McMunn*, the District Court's dismissal may have warranted a more thorough consideration of the consequences of rejecting the Daileys' request for medical monitoring: if the Daileys are likely to bring a claim for latent injury in the future, wouldn't some form of medical monitoring protect both the defendants and the plaintiffs? If such monitoring were cost-prohibitive, or physical injury to the Daileys unlikely, the District Court's decision would likely reflect the best approach to the Daileys' request. However, it is not clear the Court took these considerations into account before rendering its determination.

Medical monitoring following exposure was included in the intermediate approach to latent illness claims recommended by the Presidential Commission on Catastrophic Nuclear Accidents. However, *Dailey v. Bridgeton Landfill, LLC* presents a problem that is analogous to that in *McMunn*: the plaintiffs will likely struggle to recreate the "but-for" causation required from historical data to demonstrate that radiation from the landfill, and ultimately radioactive waste generation and disposal operations engaged in by the defendants, is responsible for elevated radioactivity levels on their property. How the Court addresses the element of causation in the plaintiffs' claim remains to be seen, but without a fundamental change to the traditional standard used, both parties are likely to vigorously dispute the other's claims.

Conclusion

In a concurring opinion to *McMunn*, Judge McKee writes that "the law in this area is simply inadequate to address claims arising under the Price-Anderson Act based on exposure to excess radiation." Judge McKee then outlines evolving case law that relaxes the standards of traditional tort law to give plaintiffs a greater opportunity to succeed in latent illness claims brought under the Price-Anderson Act. He cites precedent that allows for claims to succeed under preponderance and proportionality standards, as well as burden shifting to the defendant, concluding, nonetheless, that "none of these approaches have yet gained wide acceptance" and that "none of these approaches is close to perfect." Indeed, all of these methods would likely involve protracted evidentiary hearings, reliance on expert testimony and seem unlikely to expedite disputes.

In its Report to Congress, the Presidential Commission touched on dispute resolution mechanisms used to resolve radiation claims brought against certain companies in the UK.[12] In the absence of a suitable solution for traditionally litigated claims, it is possible that alternative dispute forums could provide a method for the swift and fair adjudication of claims. The nature and scope of such forums requires significant thought and trial and error to be successful. It's a concept worth considering further.

[12] *Appendix G, BNFL/UKAEA Agreement with Unions*, http://www.state.nv.us/nucwaste/news/rpccna/pcrcna17.htm

Are Congress and FERC Getting Ready to Take Another Bite Out of PURPA in 2018?

By Donna J. Bobbish

In an October 30, 2017 letter to the then-Chairman of the Federal Energy Regulatory Commission (FERC), 17 members of the U.S. House of Representatives[13] urged FERC to "update" its regulations implementing the Public Utility Regulatory Policies Act of 1978 (PURPA).[14] Specifically, the House members "encourage[d] FERC to . . . undertake needed modernization to [FERC's] PURPA one-mile rule regulations," which apply to determine whether an electricity generating facility seeking status as a small power production qualifying facility (QF) satisfies the size criteria set out in PURPA and FERC's regulations. They further indicated that the House Energy and Commerce Committee is considering "additional reforms" to PURPA, arguing that over the past 40 years, "the development of competitive wholesale electricity markets, which enable [QFs] under PURPA to reach more willing buyers, and the declining costs for natural gas and renewable energy resources," among other changes in energy markets, have "changed both the economics of development, as well as the impact of an increasing amount of QF output being placed on the transmission grid."

Former FERC Chairman Neil Chatterjee responded to the House members' letter on November 29 that "[t]he energy landscape that existed when PURPA was conceived was fundamentally different than it is today; solar and wind power were fledgling technologies, there was no open access to wholesale electricity markets, and natural gas was in scare supply. None

[13] Tim Walberg (R-MI), Fred Upton (R-MI), Joe Barton (R-TX), Marsha Blackburn (R-TN), Robert E. Latta (R-OH), Gregg Harper (R-MO), David B. McKinley (R-WV), Morgan Griffith (R-VA), Bill Johnson (R-OH), David Loebsack (D-IA), Larry Bucshon (R-IN), Bill Flores (R-TX), Markwayne Mullin (R-OK), Kevin Cramer (R-ND), Kurt Schrader (D-OR), Billy Long (R-MO) and Richard Hudson (R-NC).

of those things are [sic] true today. In light of such changes, I believe that the Commission should consider whether changes in the existing regulations and policies could better align PURPA implementation with modern realities." Chatterjee reminded the House members that FERC held a technical conference in 2016 to examine issues related to PURPA and further observed that "[o]ne particular area where many parties have indicated a need for a different approach is the 'one-mile rule' for qualifying facilities." Chatterjee assured the members that he will keep their concerns in mind and indicated that the letter will be placed in the public record of the pending proceeding.

On the same day that Chatterjee sent his response, one of the signatories to the October 30 letter, Rep. Tim Walberg (R-MI), introduced a bill (H.R. 4476) into the House "to modernize [PURPA] and for other purposes." H.R. 4476 not only specifies revisions to FERC's "one-mile rule," it also proposes major revisions to PURPA itself that would further circumscribe the ability of small power production QFs to obtain the benefits granted by PURPA and FERC's regulations implementing PURPA; in particular, the requirement that electric utilities purchase the output of QFs at "avoided cost" rates.

PURPA and EPAct 2005

PURPA was enacted in 1978 "as part of a package of legislation . . . to combat the nationwide energy crisis."[15] Section 210 of PURPA "seeks to encourage the development of cogeneration and small power production facilities" as "Congress believed that increased use of these sources of energy would reduce the demand for transitional fossil fuels."[16] A small power production QF is a generating facility that produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, geothermal resources or any combination thereof; and has a power production capacity which, together with any other facilities located at the same site (as determined by FERC), is not greater than 80 megawatts.[17] A cogeneration QF is a generating facility that produces electric energy and also steam or other forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes.[18]

Section 210 of PURPA required FERC to promulgate generally applicable rules to encourage QF development, including requiring utilities to purchase energy from QFs at "avoided cost" rates. Section 210 also

14 16 U.S.C. § 824a-3

15 FERC v. Mississippi, 456 U.S. 742, 745 (1982).

16 Id. at 750.

17 16 U.S.C. § 796(17)(A).

18 16 U.S.C. § 796 (18)(A).

requires states to implement FERC's rules. Generally, state public utility commissions set utilities' avoided cost rates.

Under PURPA and FERC's regulations implementing PURPA, QFs have the right to sell energy and capacity to a utility either at the utility's avoided cost or at a negotiated rate, provided that FERC has not relieved the purchasing utility from its QF purchase obligation. QFs also have the right to purchase supplementary power, back-up power, maintenance power and interruptible power from utilities and to interconnect with a utility. Owners of QFs also may be eligible for exemptions from certain provisions of the FPA, from the Public Utility Holding Company Act of 2005 and from state laws and regulations respecting the rates and financial and organizational aspects of utilities.

Congress made several significant revisions to PURPA when it passed the Energy Policy Act of 2005 (EPAct). Among other things, EPAct addressed concerns about cogeneration "PURPA machines" (generating facilities that produce token amounts of useful thermal energy) by requiring that the thermal output of a new cogeneration QF is "used in a productive and beneficial manner." Congress also amended Section 210 of PURPA to give FERC authority to terminate the requirement that an electric utility enter into a new contract or obligation to purchase electric energy from QFs if FERC finds that the QF has non-discriminatory access to specified competitive markets.[19]

In its regulations implementing EPAct, FERC, among other things, established a requirement that a cogeneration QF applicant demonstrate that a new cogeneration facility's thermal output is used in a productive and beneficial manner, stating that it will "examine the use of a cogeneration facility's thermal output to assure that the use is not a 'sham.' . . ."[20] FERC also revised its regulations governing utilities' obligation to purchase electric energy produced by QFs to provide for termination of the requirement than an electric utility enter into new power purchase obligations or contracts to purchase electric energy from QFs if FERC finds that the QFs have non-discriminatory access to a market described in Section 210(m) of PURPA.[21] FERC also created a rebuttable presumption that a QF with a capacity at or below 20 MW does not have non-discriminatory access to the market.

19 Section 210(m)

20 *Revised Regulations Governing Small Power Production and Cogeneration Facilities*, Order No. 671 at P 17, FERC Stats. & Regs. ¶ 31,203 at P 82, *order on reh'g*, Order No. 671-A, FERC Stats. & Regs. ¶ 31,219 (2006).

21 *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688, FERC Stats & Regs. ¶ 31,233 (2006), *order on reh'g*, Order No. 688-A, FERC Stats. & Regs. ¶ 3,1240 (2007), aff'd sub nom. American Forest and Paper Association v. FERC, 550 F.3d 1179 (D.C. Cir. 2008).

The "One-Mile Rule"

Under PURPA and FERC's rules implementing PURPA, the capacity of a small power production QF may not exceed 80 MW, including the capacity of any other small power production QFs that use the same energy resource, are owned by the same person(s) or its affiliates and are located at the same site.[22] Facilities are considered to be located at the same site as the facility for which QF status is sought if they are located within one mile of the facility for which QF status is sought, as measured from the electrical generating equipment of a facility for purposes of making the one-mile determination, and their respective equipment is more than a mile apart.[23] In an order issued in 2012, FERC confirmed that for purposes of certification of small power production facilities as QFs, the "one-mile rule" in FERC's regulations establishes a standard and not a rebuttable presumption.[24]

Generally, advocates of amending the "one-mile rule" argue that FERC's standard for determining whether small power production QFs are located "at the same site" can be "gamed" by project developers, who can break up a single large project into multiple facilities having different owners and located more than one mile apart, so that each individual facility does not exceed the 80 (MW) limit or the 20 MW threshold in markets where the mandatory purchase obligation has been terminated for larger QFs.

In early September 2017, the House Energy and Commerce Subcommittee on Energy held a hearing on PURPA[25] and heard testimony that some small power production QFs "are continuing to take advantage of FERC's regulations to effectively build projects that exceed the various size thresholds in the wholesale electricity markets regulated by FERC." In their October letter to FERC, the House members contend that "since FERC has made clear in its decisions that its one-mile rule is irrebuttable, parties involved cannot challenge the lawfulness of these projects." The congressmen contend that "[e]liminating the opportunity for certain QF developers to game FERC's one-mile rule will directly benefit electricity customers, who are paying billions of dollars in above-market prices for QF power sold under mandatory PURPA contracts."

Pending FERC Proceeding on PURPA Implementation

A proceeding currently is pending before FERC to examine FERC's implementation of PURPA in light of recent developments in electricity markets. At a technical conference convened at the end of June 2016, FERC heard from some 20 panelists on two issues: FERC's regulations

22 18 C.F.R. § 292.204(a)(1).

23 18 C.F.R. § 292(a)(2)(ii).

24 *Northern Laramie Range Alliance, et al.*, "Order Denying Petition for Declaratory Order," 138 FERC ¶ 61,171, *reh'g denied*, 139 FERC ¶ 61,190 (2012).

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

implementing the mandatory purchase obligation under PURPA in light of changes in the electricity markets, including, among other things, application of the "one-mile rule," and the various methods for determining avoided costs for mandatory purchases.[26]

Following the technical conference, FERC invited additional comments on two matters: the use of the "one-mile rule" to determine the size of an entity seeking certification as a small power production QF and minimum standards for PURPA-purchase contracts.

Among the comments filed in the proceeding, the American Wind Energy Association (AWEA) argues that the current one-mile rule "is a standard that has allowed developers to plan, finance, and build new renewable generation, and has provided clarity to electric utilities regarding a project's eligibility for [QF] status under PURPA." According to AWEA, "[i]f a rebuttable presumption is introduced, developers of renewable energy projects would not know whether they will have a clear path to develop generation under PURPA."

The Idaho Public Utilities Commission (IPUC) submitted comments proposing that FERC establish a rule that "a facility that is within one mile of others with which it has a common owner and shares an energy resource will be presumed to be a single QF together with those other facilities," and "[t]o qualify for PURPA, the aggregate sum of their capacity has to be within 80 MW." The IPUC also argued that "state regulatory agencies must have responsibility and discretion to determine whether a proposed project meets or exceeds the 80 MW size limited placed on QF status by [PURPA] and regulations."

EDP Renewables North America LLC (EDPR NA) argued that "[t]he one-mile rule should not be made rebuttable," because "[a]s currently implemented, the one-mile rule provides vital certainty to developers of renewable projects that must rely on PURPA to compete with incumbent utilities." EDPR NA also argued that "significant increases in the minimum distance required between affiliated QFs would artificially limit the ability of developers to bring the most competitive projects to market at their full potential scale."

Edison Electric Institute (EEI) suggests that FERC change the one-mile rule "from an irrebuttable standard to a rebuttable one, so that electric utilities have an opportunity to reasonably contest situations where gaming appears to be occurring."

Congressional Interest in PURPA Reform

Both the Senate and the House of Representatives have expressed interest in further revising PURPA. At the confirmation hearing for FERC

[26] *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Supplemental Notice of Technical Conference, Docket No. AD16-16-000 (Jun. 27, 2016).

Commissioners Neil Chatterjee and Robert Powelson held by the Senate Energy and Natural Resources Committee in early May 2017, Senator John Barasso (R-WY) asked the prospective commissioners about their plans to reform FERC's PURPA regulations to "reflect current industry conditions." Powelson described PURPA as a "1978 vintage document" that addressed "a scarcity issue" and posited that a "PUPRA 2.0" could be part of a future energy bill. Chatterjee and Powelson each committed to review the record in FERC's PURPA technical conference proceeding, but Chatterjee also told Senator Barasso that any major changes to PURPA would need to come from Congress.

During the September hearing before the Subcommittee on Energy, the Chairman, Representative Fred Upton (R-MI), asserted that "[t]his oversight hearing will be the first step in reevaluating whether the intent and purpose of PURPA is still being met or if it has already been fulfilled." Upton observed that since PURPA was enacted, energy markets have evolved so that, among other things, "renewable resources now play a significant role in the nation's fuel mix and are a major contributor in decreasing U.S. greenhouse gas emissions." According to Upton, "[c]onsidering these changed circumstances, this subcommittee must review whether revisions to PURPA are necessary or appropriate." Upton observed that EPAct made "some modest revisions to PURPA" and that "[PURPA] has largely remained unchanged since 1978."

Rep. Pallone (D-NJ), the ranking member of the House Committee on Energy and Commerce, acknowledged that "a lot has changed in the electricity sector since Congress passed Section 210 of [PURPA] in 1978 and more changes are still to come" and that "some of our members believe that the statute needs to be revised, particularly on issues like 20 estimation of avoided costs, the mandatory purchase requirement, and FERC's definition of a qualifying facility as it relates to the distance between facilities." However, he argued that "a number of the goals of PURPA are still valid today, in particular, the goals of increasing competition, encouraging development and deployment of more clean and efficient electricity generation, and ensuring equitable affordable rates for consumers are still important." He also argued that EPAct "provided significant changes to Section 210 [of PURPA]," by "allow[ing] utilities in competitive areas to avoid the mandatory purchase obligations,"and by "provid[ing] greater discretion for state utility commissions to establish methods for determining avoided costs and the duration of power purchase agreements."

PURPA Modernization Act

The introduction of H.R. 4476 may signal that some members of Congress may be ready to undertake a "PURPA 2.0" and may not be content to leave reform of FERC's PURPA rules to FERC alone. The bill would require FERC to issue, no later than 180 days after the bill's enactment, a final rule amending FERC's PURPA regulations to establish a presumption that facilities located one mile or more away from each other are not located at the same site and that facilities located within one mile of each other are located at the same site and to allow any person to rebut this presumption.

H.R. 4476 would further require FERC to take into account seven factors in determining whether a facility is located at the same site as the facility for which QF status is sought: the extent to which the owners or operators of the facilities are affiliated or associated with each other, or under the control of the same company or person; the extent to which the owners or operators of the facilities have treated the facilities as a single project for purposes of the regulatory filings or applications; whether the facilities use the same energy resource; whether the facilities have a common generator lead line or connect at the same or nearby interconnection points or substations; the extent to which the owners or operators of the facilities have a common land lease or land rights with respect to land on which the facilities are located; the extent to which the owners or operators of the facilities have common financing with respect to the facilities; and the extent to which the facilities are part of a common development plan or permitting effort, even if the interconnection of the facilities occurs at separate points.

In addition to specifying amendments to FERC's one-mile rule, H.R. 4476 also would lower the mandatory purchase obligation threshold established by FERC from 20 MW to 2.5 MW, by establishing a presumption that a small power production QF with an installed generation capacity of 2.5 MW or greater has non-discriminatory access to transmission and interconnection services and wholesale markets.

Even more significant, however, H.R. 4476 also would amend Section 210 of PURPA to provide that an electric utility will not be required to purchase electric energy from a small power production QF if the applicable state regulatory agency submits to FERC a written determination either that the electric utility has no need to purchase electric energy from the small power production QF in order to meet its obligation to serve customers, or the electric utility employs integrated resource planning and conducts a competitive resource procurement process for long-term energy resources that allows small power production QFs to supply energy to the electric utility in accordance with the electric utility's integrated resource plan. H.R. 4476 would allow state public utility commissions, such as the IPUC, which previously has had disagreements with FERC over the IPUC's implementation of FERC's PURPA rules, to relieve utilities under its jurisdiction from the mandatory purchase obligation under PURPA.

In early December, H.R. 4476 was referred to the Subcommittee on Energy of the House Committee on Energy and Commerce in early December, and on January 19, the Subcommittee held a legislative hearing on three bills proposing dramatic changes to regulation of the energy sector, including H.R. 4476.

In his opening statement, the Chairman of the Energy and Commerce Committee, Rep. Greg Walden (R-OR), stated that H.R. 4476 "updates" PURPA "to ensure it serves the interests of consumers and power suppliers for years to come. Most notably, the PURPA modernization bill will address the concern that certain facility developers are successfully evading the intent of FERC's 'one-mile rule.'" Rep. Bobby Rush (D-IL), the ranking member of the Energy Subcommittee, on the other hand, expressed his concern that the changes to PURPA and FERC's regulations in the bill "would replace a system that currently works well in ensuring a competitive environment for smaller, privately owned energy producers with one that severely reduces competition" and argued that "if it ain't broke, it don't need a fix." Rep. Frank Pallone (D-NJ), the ranking member of the Energy Committee, said that, while he is not completely opposed to updating PURPA, "two of the three main components of H.R. 4476 represent "a direct assault on PURPA that would solidify the monopoly power of utilities in areas without competitive wholesale or retail markets." Pallone expressed a willingness to try to address the one-mile rule in a bipartisan fashion.

Among the witnesses appearing at the hearing, FERC's General Counsel, James Danly, testified that the one-mile rule is a FERC-adopted rule that may be changed by FERC and that "Congressional guidance as to what changes, if any, that Congress believes [FERC] should make to the one-mile rule would be helpful." In response to Rep. Upton's question as to when FERC might conclude its proceeding, Danly indicated that he did not know. With respect to the proposed amendments to Section 210(m) of PURPA, Danly testified that H.R. 4476 would change the current 20 MW threshold established by FERC to 2.5 MW for small power production QFs, shifting the burden on small power production QFs above 2.5 MW to demonstrate that it does not have non-discriminatory access to markets.

With respect to the section of the bill that would relieve an electric utility of its mandatory purchase obligation if the appropriate state regulatory authority submits to FERC a written determination that the electric utility either does not need to purchase the output of a small power production QF or uses integrated resource planning, Danly testified that "this proposal fundamentally changes PURPA from a national energy program, to essentially, a state-by-state energy program— with a likelihood of substantially varying potential outcomes state-by-state. The proposal would, in effect, eliminate PURPA's directive of mandatory purchases by electric utilities of electric energy produced by small power production QFs, as it would leave it up to each relevant state regulatory agency or non-regulated electric utility to determine if there is a need for QF power and thus whether the utility must purchase from a small power production QF."

Danly further testified that FERC "is reviewing the comments that came out of the technical conference" and is "actively working . . . with members of the Subcommittee... to talk about possible legislative reform."

Karl Rabago of Rabago Energy, LLC, a consultant, testified that "[r]ather than maintaining the current FERC and state PURPA framework. . . H.R. 4476 would effectively eliminate the must-buy provisions of PURPA" and instead, would allow a utility to "refuse to purchase energy or capacity from a [small power production QF] if the utility unilaterally determines it has 'no need' for energy or capacity."

On behalf of the National Association of Regulatory Utility Commissioners (NARUC), which represents public utility commissions, Travis Kravulla, Vice Chairman of the Montana Public Service Commission, testified in support of H.R. 4476, arguing that it "straightforwardly acknowledges that a competitive process should be allowed to substitute for PURPA's mandatory purchase obligation." Kravulla testified that "[m]ore than half the States . . . have their own renewable energy mandates, and even those which do not . . . have shown substantial additions to renewable capacity, not because of PURPA, but because of the falling cost curve of renewable technologies, such as solar and wind."

In 2018, FERC could decide to issue a proposed rulemaking based on its review of the testimony and comments it received in the 2016 PURPA technical conference, and include the proposed revisions to its QF regulations included in H.R. 4476, creating a rebuttable presumption with respect to the one-mile rule and establishing a mandatory purchase obligation threshold lower than 20 MW.

At this time, no further action on H.R. 4476 is scheduled.

"Deep State" FERC? What Might FERC's Response to DOE Grid Resiliency Rule Tell Us About FERC Under the Trump Administration?

By Donna J. Bobbish

On January 8, 2018, two days before the January 10 extended deadline set by the Secretary of Energy, the Federal Energy Regulatory Commission (FERC) issued its much-anticipated response to the Proposed Rule on Grid Reliability and Resilience Pricing submitted to FERC by Rick Perry, the Secretary of Energy, in late September 2017.[27] In a 5-0 decision, FERC declined to adopt the rule proposed by Perry to require FERC-approved regional transmission organizations (RTOs) and independent system operators (ISOs) with energy and capacity markets and a tariff that contains a day-ahead and a real-time market to allow for the recovery of costs and a return on investment by "eligible grid reliability and resiliency resources" participating in those markets.[28] At the same time, FERC also initiated a new proceeding to "take additional steps to explore resilience issues in RTOs and ISOs."[29]

Following the issuance of the FERC Order, Perry issued a statement that, as intended, his proposed rule "initiated a national debate on the resiliency of our electric system," and said that he is looking forward to continuing to work with FERC commissioners to ensure the integrity of the electric grid. However, Corey Lewandowski, a former manager of the 2016 Trump presidential campaign, took to social media to characterize FERC's action as evidence that "[t]he deep state is very real," and to characterize

[27] *Grid Reliability and Resilience Pricing*, "Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures," 162 FERC ¶ 61,012 (Jan. 8, 2018)("FERC Order")

[28] "*Grid Resiliency Pricing Rule*," Notice of Proposed Rulemaking, Docket No. RM18-1-000 (issued Sept. 28, 2017) ("Pricing Rule").

[29] FERC Order at P 18.

FERC as "[m]ore government officials who don't support the Trump agenda." In response to Lewandowski, numerous observers pointed out that all but one of the five FERC commissioners who voted on the order were appointed by President Trump and that three of those commissioners, including the chairman, are Republicans. Nonetheless, Lewandowski's heated criticism has raised in some minds the question of what FERC's action on the DOE Pricing Rule reveals about how the newly constituted FERC intends to function as an independent agency under the Department of Energy (DOE) in an administration headed by a president who, in the context of another governmental department, reportedly has complained about not being able "to simply give orders to 'my guys.'"[30]

DOE Pricing Rule

Under Section 402 of the Department of Energy Organization Act (DOE Organization Act), which allows the Secretary of Energy to propose rules, regulations and statements of policy of general applicability with respect to any function under FERC's jurisdiction, Perry directed FERC to consider a proposed Pricing Rule under which FERC would amend its regulations governing the tariffs and operations of FERC-approved ISOs and RTOs[31] to require that RTO and ISO tariffs provide a just and reasonable rate for the purchase of electric energy from an "eligible reliability and resilience resource" and for the recovery of costs (such as operating and fuel expenses, and costs of capital and debt) and a return on equity for such resource dispatched during grid operations. The proposed Pricing Rule prescribed that the just and reasonable rate ensure that each eligible resource is fully compensated for the benefits and services it provides to grid operations, including reliability, resiliency and on-site fuel assurance, and that each eligible resource recovers its fully allocated costs and a fair return on equity.

The proposed Pricing Rule defined "eligible grid reliability and resiliency resources" as any electric generation resource that is physically located within a FERC-approved ISO or RTO; is able to provide essential energy and ancillary reliability services, such as voltage support, frequency services, operating reserves and reactive power; has a 90-day fuel supply on site enabling it to operate during an emergency, extreme weather conditions, or a natural or man-made disaster; is compliant with all applicable federal, state and local environmental laws, rules and regulations; and is not subject to cost-of-service rate regulation by any state or local regulatory authority. This definition generally was interpreted to include nuclear and coal-powered electricity generating facilities.

[30] Parker, Ashley, et al., "Trump sought release of classified Russia memo, putting him at odds with Justice Department," *The Washington Post*, Jan. 27, 2018.

[31] 18 C.F.R. 35.29(g).

In support of the proposed Pricing Rule, DOE argued that "the changing electricity sector is causing the closure of many coal and nuclear plants"[32] and that because wholesale pricing in organized markets does not adequately consider or accurately value benefits that fuel-secure generation resources provide to the grid, such resources often are not compensated for those benefits.[33] DOE also asserted that "the continued loss of fuel-secure generation must be stopped" because these generation resources "are necessary to maintain the resiliency of the electric grid."[34] According to DOE, FERC must adopt rules requiring FERC-jurisdictional RTOs and ISOs to "reduce the chronic distortion of the markets that is threatening the resilience of the Nation's electricity system."[35]

FERC's Order

FERC finally achieved a full complement of five commissioners on December 7, 2017, when Kevin J. McIntyre was sworn in and assumed the chairmanship. On that same day, McIntyre sent a letter to Secretary Perry requesting a 30-day extension of time to take action on the proposed Pricing Rule, observing that FERC had received over 1,500 comments on the Pricing Rule.

While the proposed Pricing Rule received strong support from companies with interests in coal and nuclear resources, such as FirstEnergy Service Company, Exelon Corporation and Murray Energy Corporation, several commenters opposed the Pricing Rule as a political effort by President Trump to honor his campaign promises to save the coal industry. Among others, Tenaska, Inc. argued that that "[a]s an 'independent agency of the United States,'" FERC "should resist the administration's attempt to use FERC to implement a political agenda. . . ." A bipartisan group of eight former FERC commissioners urged FERC "not to move forward" with DOE's proposed Pricing Rule, as to do so "would be a significant step backward from the Commission's long and bipartisan evolution to transparent, open, competitive wholesale markets."

After considering the Proposed Rule, FERC determined that neither the Proposed Rule nor the record established in the proceeding satisfied the requirement of Section 206 of the FPA that, before adopting the proposed Rule, FERC determine first that the existing RTO/ISO tariffs are unjust, unreasonable, unduly discriminatory or preferential, and second, that the new RTO/ISO tariff provisions proposed in the Proposed Rule are just, reasonable and not unduly discriminatory or preferential. FERC stated that "given those legal requirements, we have no choice but to terminate Docket No. RM18-1-000," the proceeding in which FERC considered the

32 Pricing Rule at p. 3.

33 Pricing Rule at p. 5.

34 Pricing Rule at p. 10.

35 Pricing Rule at p. 10.

Proposed Rule.[36] FERC found that assertions of grid resilience or reliability issues due to potential retirements of particular resources do not demonstrate the unjustness or unreasonableness of existing RTO/ISO tariffs. Further, FERC found that extensive comments submitted by RTOs and ISOs do not point to any past or planned generator retirements that may be a threat to grid resilience. FERC also found that the record in the proceeding does not demonstrate that allowing all eligible resources to receive a cost-of-service rate regardless of need or cost to the system would be just and reasonable.[37]

However, FERC also observed that "the Proposed Rule and the record developed to date shed additional light on resilience more generally and on the need for further examination . . . of the risks that the bulk power system faces and possible ways to address those risks in the changing electric markets."[38] FERC established a new proceeding[39] to "develop a common understanding of what resilience of the bulk power system means and requires, to understand how each RTO and ISO assesses resilience in its geographic footprint and to use this information to evaluate whether additional FERC action regarding resilience is appropriate at this time."[40] FERC required RTOs and ISOs to respond to some 26 questions in these three areas, and also provided for the public to file reply comments to the RTO and ISO submittals.[41]

Three commissioners issued separate concurring statements. Commissioner Cheryl LaFleur expressed her strong support for FERC's decision not to adopt the rule proposed by the Secretary of Energy, as well as her support of FERC's action "to start a focused proceeding to explore how the RTOs/ISOs address the resilience of the grid in their respective regions, and whether there are additional steps [FERC] should take to support resilience." Commissioner Neil Chatterjee applauded Secretary Perry's "bold leadership in jump-starting a national conversation" on the resiliency of the U.S. bulk power system and expressed his belief that "it would have been prudent, in addition to establishing the proceeding in Docket No. AD18-7-000, for [FERC] to issue an order to show cause pursuant to section 206 of [the FPA] directing each RTO/ISO to either submit tariff provisions to provide interim compensation for existing generation resources that may provide necessary resilience attributes and are at risk of retirement before the conclusion of the proceeding established today or to show cause why it should not be required to do so." Commissioner Richard Glick expressed his confidence

36 FERC Order at P 14.

37 FERC Order at P 15.

38 FERC Order at P 17.

39 *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket No. AD18-7-000.

40 FERC Order at P 18.

that FERC "will approach this new examination into the resilience of the bulk power system in the same manner it considers all other matters—with a non-partisan perspective and with a view solely on what the facts provide and the law requires." According to Glick, "[i]f the RTOs and ISOs demonstrate that the resilience of the bulk power system is threatened we should act. If not, we should move on."

The FERC Order evidences a desire for bipartisanship in crafting an approach to the Pricing Rule that could be supported by all five commissioners. In addition, while the FERC Order was fairly blunt in concluding that the proposed Pricing Rule was not supported by facts, it did not challenge the stated concern behind the Proposed Rule, affirming at the outset that "[t[he resilience of the bulk power system will remain a priority of this Commission"[42] and reaffirming at the conclusion that "[p]romoting resilience of the bulk power system is an important issue for the Commission."[43]

By establishing a new proceeding to consider grid resiliency and reliability, FERC demonstrated a willingness to examine issues of importance to the Trump administration. At the same time, in deciding to effectively "start over" to examine grid reliability and resiliency within a framework developed by FERC—as opposed to DOE, FERC reaffirmed its role as an independent regulatory agency under DOE charged with implementing and enforcing federal laws. FERC reframed the issue away from the interests of any particular generating resources, stating "[a]lthough the Proposed Rule focuses on one possible aspect of grid resilience—secure onsite fuel—we conclude that a proper evaluation of grid resilience should not be limited to that single issue, and should instead encompass a broader consideration of resiliency issues, including wholesale electric market rules, planning and coordination, and NERC standards."[44] FERC also appeared to reject any suggestion that addressing grid reliability is somehow at odds with FERC's support for competitive wholesale electricity markets, stating: "[t]he Commission's endorsement of markets does not conflict with its oversight of reliability, and the Commission has been able to focus on both without compromising its commitment to either."[45] Finally, FERC did not commit to take any particular action at the conclusion of the new proceeding, stating "we expect to review the additional material and promptly decide whether additional Commission action on this issue is warranted."[46]

41 FERC Order at Ordering Paragraph (A).

42 FERC Order at P 1.

43 FERC Order at P 28.

44 FERC Order at P 19.

45 FERC Order at P 11.

46 FERC Order at P 28.

Observers of the energy industry are wondering whether, FERC will be called on to thread that needle again during the tenure of the Trump administration.

RTO/ISO responses to FERC's Order are due no later than March 8, while reply comments to the RTO/ISO responses are due no later than April 9.

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