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ELECTRICITY LAW DEVELOPMENTS – January 31, 2019
Prepared for ELCON

This report summarizes recent developments in FERC proceedings in which ELCON has been active and other matters of interest to industrial consumers. It is the first bimonthly issue for 2019. Inside this issue:

I. REGULATORY PROCEEDINGS

II. COURT PROCEEDINGS

New developments since the November 2018 issue of Electricity Law Developments are in bold.

I. REGULATORY PROCEEDINGS

A. <u>Final Rule on Large Generator Interconnection (Docket No. RM17-8)</u>

On April 19, 2018, FERC issued a final rule that adopts certain reforms of interconnection procedures for large generators (>20 MW) to promote transparency and efficiency. FERC has classified the reforms into three categories as based in "certainty," "transparency" and "efficiency".

Certainty Reforms

- Removing a limitation on an interconnection customer's ability to construct interconnection facilities and stand-alone network upgrades.
- Requiring that all transmission providers establish more-accessible interconnection dispute resolution procedures.

Transparency Reforms

- Requiring transmission providers to outline and make public a method for determining contingent facilities.
- Requiring transmission providers to list the study processes and assumptions for forming the network models used for interconnection studies.
- Revising the definition of "Generating Facility" to explicitly include electric storage resources.
- Establishing reporting requirements for aggregate interconnection study performance.

Efficiency Reforms

- Allowing an interconnection customer to request a level of interconnection service that is lower than its generating facility capacity.
- Requiring transmission providers to allow for provisional interconnection agreements that provide for limited operation of a generating facility prior to completion of the full interconnection process.
- Requiring transmission providers to create a process for the use of surplus interconnection service.

- Requiring transmission providers to set forth a procedure to assess and, if necessary, study changes in an interconnection customer's proposed technology that occur during the interconnection process to determine if such changes would constitute a material modification.

The final rule does not adopt proposed reforms related to requiring periodic restudies, self-funding of network upgrades, the posting of congestion and curtailment information, and the modeling of electric storage resources (referencing the limited experience with such resources and the value of regional flexibility). Nor does the final rule take action on two issues for which it had requested comment, cost caps for network upgrades (which ELCON had opposed as premature and inconsistent with cost causation principles), on the basis that "there is insufficient evidence in the record to support cost caps as a preferred solution to reducing variances from cost estimates and providing greater cost certainty to interconnection customers," and affected systems coordination.

The final rule becomes effective 75 days after its pending publication in the *Federal Register* and compliance filings are due 15 days thereafter.

Requests for rehearing and/or clarification have been filed by Duke Energy, Southern Company, EEI, Southern California Edison and separately a coalition of California utilities, NYISO, Arizona Public Service Co., AWEA, E.ON Climate & Renewables, APPA, Ameren Services Co., and MISO Transmission Owners. There were also requests for extension of time. For example, the ISO RTO Council requested that the 75 day period for compliance filings be extended to 145 days. **FERC has granted an extension of the compliance filing deadline pending its action on the rehearing filings.**

B. Proposed Rule on "Data Collection for Analytics and Surveillance and Market-Based Rate Purposes" (Docket No. RM16-17)

On July 21, 2016, FERC issued a new notice of proposed rulemaking ("NOPR") that would impose data collection requirements on power marketers with market based rate authority and entities engaged in trading of virtual products in the organized day-ahead markets or of financial transmission rights. The new NOPR replaces FERC's earlier NOPRs on "connected entity" data (issued September 17, 2015 in Docket No. RM15-23) and on ownership information in market based rate ("MBR") filings (issued December 17, 2015 in Docket No. RM16-3), which FERC has now withdrawn. The connected entity NOPR in particular generated substantial controversy as it would have imposed overly burdensome and intrusive requirements that read like a wish-list of enforcement staff, and it was strenuously opposed by ELCON and many other commenters.

As noted by FERC, the new NOPR "reflects departures" from the connected entity NOPR, and it proposes to adopt changes similar to those in the MBR NOPR. The new NOPR includes a reworked and substantially narrowed definition of the connected entities that need to be reported. It also proposes to adopt certain changes to reduce and clarify the scope of ownership information that MBR sellers must provide, revise the information required in asset appendices, and eliminate the requirement from Order No. 816 that MBR sellers submit corporate organizational charts.

Accordingly, the new NOPR considerably reduces the scope of the reporting that would have been required under the former, now-withdrawn NOPRs and reflects an unusual degree of responsiveness to the concerns raised by ELCON and others in the regulated community. However, the procedures for reporting that FERC now proposes are entirely new and for that reason warrant careful review. In particular, the new NOPR proposes that entities submit the connected entity information and most of the MBR information electronically into a relational database using an XML schema, with the terms and values to be followed by submitters defined in a data dictionary posted on FERC's website. FERC asserts that this approach would enable unified submission of connected entity and MBR information and would avoid multiple submissions with the RTOs/ISOs acting as middlemen, which were key concerns with the former connected entity NOPR.

Scope of Reporting of Connected Entity Information

Under the new NOPR, the connected entity reporting requirements would apply only to sellers with MBR authority and to entities that trade virtual products (sales or purchases in an RTO/ISO day ahead market that do not go to physical delivery) or financial transmission rights (including congestion contracts or rights) in the organized markets ("Virtual/FTR participants").

Compared to the former NOPR, the connected entity information required to be reported would be limited as follows:

- Affiliate information would be required only for entities that are either: (i) an "ultimate affiliate owner" of the entity, as defined for purposes of MBR requirements in section 35.37(a)(2); (ii) an entity that participates in Commission-jurisdictional organized wholesale electric markets; or (iii) an entity that purchases or sells financial natural gas or electric energy derivative products that settle off of the price of physical electric or natural gas energy products.

- The definition of "trader" required to be named in reports would now be limited to "a person who makes, or participates in, decisions and/or devises strategies for buying and selling physical or financial electric or natural gas energy products."

- The proposed requirement for the reporting of debt instruments would be eliminated.

- The category of contractual entity reporting would be considerably narrowed to entities that have entered into an agreement with a submitting entity that "confers control over an electric generation asset that is used in, or offered into, wholesale electric markets."

MBR sellers and Virtual/FTR participants would be required to make a baseline submission within 90 days of publication of a final rule and subsequently to report changes in connection, such as an entity becoming or ceasing to become a connected entity or a contractual connection that exceeds a *de minimis* threshold of 100 MW, within 30 days of the change.

Attachment B of the new NOPR provides in tabular form a more detailed comparison of the former connected entity NOPR requirements with the new NOPR's requirements.

Market-Based Rate Information

Respecting MBR information, the new NOPR would revise the reporting requirements in a fashion similar to what FERC had proposed in the former MBR NOPR. In particular:

- MBR sellers need to identify only those affiliate owners that either: (1) are an "ultimate affiliate owner," defined as the furthest upstream affiliate owner(s) in the ownership chain; or (2) have a franchised service area or MBR authority, or directly own or control generation; transmission; intrastate natural gas transportation, storage or distribution facilities; physical coal supply sources or ownership of or control over who may access transportation of coal supplies.

- Where an MBR seller is directly or indirectly owned or controlled by a foreign government or any political subdivision of a foreign government or any corporation which is owned in whole or in part by such entity, the MBR seller would need to identify such foreign government, political subdivision, or corporation as part of its ownership narrative. As was previously the case, FERC still does not adequately explain this proposed requirement, stating merely that it "is useful in protecting public utility customers against inappropriate cross-subsidization and affiliate abuse concerns possible when controlling interests in a public utility are [foreign] held."

- With respect to any owners that an MBR seller represents to be passive, the MBR seller would need to affirm in its ownership narrative that its passive owner(s) own a separate class of securities, have limited consent rights, do not exercise day-to-day control over the company, and cannot remove the manager without cause.

In view of the new relational database capabilities, under the new NOPR an MBR seller would generally have to report only its own assets (and those of any affiliate without MBR authority), and according to FERC the net result would be an overall decrease in burden on

MBR sellers. At paragraphs 35-39 of the NOPR, FERC also proposes various technical revisions to the information required to be reported regarding such assets. MBR sellers would be required to update the relational database information quarterly with any changed information that did not invoke a change in status or 30-day change-in-connection filing.

Attachment A of the new NOPR provides in tabular form a more detailed comparison of the former ownership NOPR and existing MBR requirements with the new NOPR's requirements.

Public Comments on the NOPR

About 30 sets of comments were filed, many raising substantial concerns with the NOPR.

ELCON and AF&PA submitted joint comments on the new NOPR. The comments pointed out that the new NOPR contains a number of new proposals reflecting a radical departure from the earlier proposals that must be carefully scrutinized. The proposals that entities submit the Connected Entity information and most of the MBR information electronically into a relational database using an as-of-yet undefined XML schema raise a host of new issues the Commission should address before adopting any final rule. Thus many of the proposed requirements require further definition and refinement. ELCON and AF&PA focused on: (1) the terms in the NOPR that established the scope of the reporting requirements related to Connected Entities; (2) particular aspects of the proposed changes to the MBR reporting requirements; and (3) confidentiality issues. Specifically, the comments addressed: need for clarification of the scope of "participates" in markets; issues with purchase or sale of natural gas derivative products; trader identity reporting; passive investments; treatment of QFs; quarterly reporting; long-term purchase agreements; foreign ownership information; and the heightened need to provide confidentiality protection.

EPSA made a number of recommendations. Most notably, and consistent with ELCON's viewpoint:

- Connected Entities based on "ownership" should be limited to ownership relationships in scope of the sale of energy in FERC-jurisdictional organized wholesale markets. The definition proposed should be revised to eliminate the use of "derivatives," to be replaced with terms describing specific financial transactions entered into pursuant to an ISO/RTO Tariff, eliminating "natural gas energy products" and "natural gas energy derivatives."
- The definition of a Connected Entity trader would include those persons managing and/or directing decisions for a trading desk or approving strategies for the trading desks of an MBR seller engaged in trading of physical or financial electricity or capacity products pursuant to an ISO/RTO tariff or protocol that has been approved or permitted to take effect by FERC.

EPSA also sought extension of many of the deadlines.

Similarly, the Financial Marketers Coalition commented that FERC has failed to properly assert its jurisdiction over virtual transactions, because it has not demonstrated that it has been granted such statutory authority. The Coalition also addressed: (1) the definition of the term "Trader;" (2) the expected treatment of traders under investigation for market manipulation; (3) the Commission's decision to exclude ARRs from the Connected Entity reporting requirements; (4) the process for requesting extensions of time; (5) the Commission's need for additional information related to Virtual/FTR Participants; and (6) concerns related to technical and privacy issues with the Commission's proposed relational database and website interface.

Berkshire Hathaway focused on the extreme burdens of the requirement to seek out the activities of its non-energy affiliates in its non-centralized business structure, the disclosures required in the data dictionary that are not discussed or justified in the preamble, and the "potentially broad" definition of trader.

NRECA sought an expanded exemption for cooperatives and like ELCON and many other commenters sought further revision and clarification of the definition of "Trader".

EEI filed perhaps the most detailed comments opposing many aspects of the NOPR. In 60 pages of comments and appendix, in addition to comments to narrow considerably the definition of "Trader", opposing the broad applicability to natural gas financial products, and other specific points, EEI dug into the specifics of the data dictionary, pointing out the many ways in which it is far more expansive than signaled in the text of the NOPR. EEI's overarching points were that "the NOPR does not explain why the Commission needs the proposed new information or what the Commission intends to do with the information" and that "the preamble to the NOPR and proposed regulatory text do not fully reflect the expansive scope of the proposed new information, much of which is set out only in the draft data dictionary attached to the NOPR."

The Financial Institutions Regulatory Group also raised concerns about the scope of the NOPR and focused on the subparts to the definition of "Connected Entity" – Ownership, Traders and Contracts.

TAPS took a more moderate position than most commenters, supporting the relational database and focusing on the need for clarification and greater consistency.

APPA was the leading commenter that expressed support for the NOPR. Still, APPA sought the following clarifying revisions, requesting that FERC: (1) clarify that the relational database will retain historical data and not just a snapshot of current data; (2) clarify the requirements for MBR sellers' change in status reporting, change in connection reporting, quarterly reporting, and triennial filings to ensure that the information in the relational database will be accurately maintained; (3) clarify the regulatory text to conform to the Commission's proposed changes to the required asset appendix information; (4) clarify that the Commission is not changing its substantive policy concerning passive ownership interests; and (5) employ a phased implementation of the revised MBR Information filing requirements that temporarily overlaps with continued submittals of tailored affiliate-reporting requirements by MBR sellers, including asset appendices and organization charts, to ensure that the new relational database is providing the Commission with the necessary information.

FERC action on the NOPR remains pending.

C. Final Rule on Electric Storage (Docket Nos. RM16-23 and RM18-9)

On February 15, 2018, FERC issued a final rule requiring the RTOs/ISOs to revise their tariffs to establish a participation model for electric storage resources that consist of market rules that properly recognize the physical and operational characteristics of electric storage resources.

The participation model for electric storage resources must provide the following terms:

- Ensure that a resource using the model is eligible to provide all capacity, energy and ancillary services that it is technically capable of providing.
- Ensure that the resource can be dispatched.
- Ensure that the resource can set the wholesale market clearing price as both a seller and buyer consistent with existing market rules.

- Account for the physical and operational characteristics of electric storage resources through bidding parameters or other means.
- Set a minimum size requirement that does not exceed 100 kilowatts, which FERC said "balances the benefits of increased competition with the ability of RTO/ISO market clearing software to effectively model and dispatch smaller resources often located on the distribution system."

The final rule also requires that the sale of electric energy from the wholesale electricity market to an electric storage resource that the resource then resells back to those markets must be at the wholesale LMP.

The final rule establishes an extended implementation schedule, requiring filing of tariff changes 270 days after publication in the Federal Register and implementation of those changes 365 days later.

FERC deferred action on proposed changes related to aggregation of distributed energy resource. Instead, it set a Technical Conference for April 10-11, 2018 to address aggregation and other distributed energy resource issues. Seven panels will address:

- Economic dispatch, pricing, and settlement of DER aggregations;
- Operations implications of DER aggregation with state and local regulators;
- Participation of DERs in RTO/ISO markets;
- Collection and availability of data on DER installations;
- Incorporating DERs in modeling, planning and operations studies;
- Coordination of DER aggregations participating in RTO/ISO markets; and
- Ongoing operational coordination.

A number of rehearing and/or clarification requests were filed and remain pending. The extent and tone of the rehearing requests signal that the final rule may be challenged in court.

The Organization of MISO States (OMS) raised three issues: (1) FERC should clarify that an RTO/ISO may request, at the behest of its stakeholders, tariff provisions that recognize a unique regional situation that requires additional oversight by retail regulators of resources connected to the distribution system that participate in wholesale markets; (2) FERC should clarify that "contractually permitted" requires compliance with applicable rules and policies for each distribution utility that may be established now or in the future by a state or local regulator, that authority to participate in a retail program is not deemed authority to participate in a wholesale market, and that the final rule does not impact existing rules related to interconnection or operation of resources; and (3) FERC should clarify that the RTOs/ISOs may adopt tariff provisions that requires compliance with applicable rules as confirmed by the distribution utility and retail regulatory authority before an asset can be authorized to participate.

NARUC shared the first objection raised by OMS raised by the statement in the final rule that States cannot "decide whether electric storage resources in their state that are located behind a retail meter or on the distribution system are permitted to participate in the RTO/ISO markets through the electric storage resource participation model." NARUC presented an extensive argument that the final rule "improperly extended federal jurisdiction to a matter within the jurisdiction of the States: authority to determine whether resources on the State-jurisdictional distribution system [or behind the meter] can participate in the RTO/ISO markets" under FPA Section 201 and FERC Order Nos. 719 and 2006-A. NARUC argued that FERC has authority over "how" such resources can participate in the organized markets but States retain authority over "whether" they can participate.

PG&E agreed. Further, it asked FERC to clarify that the final rule is not intended to "suggest that the state no longer has jurisdiction to determine how power flowing from the distribution grid, through the customer meter and then into the storage resource located behind the customer meter is to be split between retail consumption, and wholesale charging for later discharge into the wholesale markets," as otherwise the storage resource could be used "as a means to completely bypass retail rates for its on-site electricity consumption . . . ."

Xcel Energy also argued that FERC exceeded its jurisdiction by infringing on retail sales. Further, Xcel Energy said that FERC should: (1) "prohibit distribution-connected and behind-the-meter electric storage resources from participating in both the wholesale and retail markets until evidence exists that metering technology and protocols exist that can differentiate that participation" to avoid disruption to the retail markets; (2) establish a more relaxed timeline and provide for cost recovery by distribution providers; and (3) allow system average wholesale distribution charges for use of the distribution network. Xcel Energy believes that the final rule "creates significant metering problems, and . . . provides no record support for the commission's conclusion that separating wholesale and retail activity by individual resources is possible" with the result that the final rule could "significantly disrupt the state regulated retail market that depends on accurate metering of retail energy consumption and production . . . ."

TAPS joined the filers arguing that FERC exceeded its jurisdiction. TAPS claimed that the final rule erred by: (1) rejecting a Relevant Electric Retail Regulatory Authority ("RERRA") opt in/opt-out patterned on Order No. 719-A for storage resources connected to distribution facilities or behind the retail meter; and (2) rejecting TAPS' recommendation that, in addition to requiring adequate metering, the Commission require distributed storage resources to make a binding choice to participate exclusively either in the wholesale markets, or at retail. TAPs observed that “"[w]hen wholesale market prices are high, there is an obvious financial incentive to buy from a retail provider at the average price while selling into the wholesale market at the peak price," and that "if the owner of a distributed storage resource could simultaneously purchase energy at retail and sell energy to the wholesale market in such conditions, it could reap enormous financial returns and shift costs to other retail customers—all without ever changing the physical state of charge of its storage resource."

The California Energy Storage Alliance asserted that FERC’s rules should prohibit the application of transmission charges, such as the Transmission Access Charge (“TAC”) charge in the California Independent System Operator (“CAISO”), for wholesale charging of energy storage devices when energy for charging is later resold.

MISO expressed concern about the interrelationship between storage resources and the deferred distributed resource issues, and in a lengthy filing it sought both an extension of the final rule’s deadlines and more flexibility regarding minimum size, bid parameters, and implementation time frame.

AMP, APPA and NRECA filed a joint rehearing request echoing other filers on the jurisdictional issue, the need for an opt in/opt out mechanisms, and a need for coordination with the outcome on the deferred DER issues. Their filing asserted that the final rule would be an "unprecedented federal intrusion into the authority of states to regulate retail electric service, [and] an unprecedented expansion of federal authority over facilities for the local distribution of electric energy."

CAISO sought the following clarifications: (1) it is unnecessary for the RTO/ISO itself to directly meter storage resources (only that some entity directly meter them); (2) an RTO/ISO can require storage resources to resolve retail double-billing issues with their retail energy provider as a condition of wholesale market participation; and (3) charging a storage resource pursuant to RTO/ISO dispatch provides a service such that the storage resource should not incur transmission charges.

EEI asserted that in the case of storage paired with retail load, the burden of metering should not be the responsibility of the distribution utility. Instead, according to EEI, the storage resource should have the burden to pay for any metering or other costs associated with separating its loads, or else the entire load can and should be treated as retail load. EEI also raised issues similar to those raised by the other filers, including with respect to the need for an opt-in/opt-out option, the need for coordination with the deferred DER issues, and the lack of supporting evidence for the 100 kW threshold.

AES's filing argued that the final rule erred in requiring storage resources to be dispatchable and in failing to recognize the need for technology-specific participation models. AES also sought extension of the final rule's deadlines.

PJM requested that FERC clarify that the final rule did not mandate a particular method for "accounting for the characteristics of energy storage resources" but instead allows for phased implementation to be considered on compliance.

FERC actions on the rehearing requests and in response to the Technical Conference are pending.

D. Technical Conference on PURPA Implementation Issues (Docket No. AD16-16)

On June 25, 2018, the Edison Electric Institute ("EEI") filed unsolicited "supplemental comments" in FERC's long-standing general administrative docket on PURPA issues, No. AD16-16. In the comments, EEI urged that FERC "undertake a holistic approach review of its rules and regulations implementing PURPA to ensure that they are consistent with today's electric markets." EEI asserts that FERC's current PURPA regulations "promote the uneven, unplanned, and uneconomic development of QFs and provide for subsidies that promote QFs at the expense of customers, system reliability, and other more competitive resources."

EEI specifically requested that FERC issue a NOPR to address the following topics, as parts of such a "holistic" review:

Allegedly above-market payments to QF resources and establishment of a legally enforceable obligation.

EEI states that FERC should provide greater latitude to states to establish avoided costs at market prices (to be updated regularly), and should give states latitude to determine when the legally enforceable obligation is incurred for purposes of fixing the avoided costs. Respecting determination of avoided costs in states with retail access, EEI seeks revision of FERC's regulations so that states may determine that a purchasing utility's avoided costs of energy and capacity can be set to $0 to the extent it no longer has any load-serving obligations and/or it has divested all of its generation resources. Further, for utilities that are providers of last resort (POLR), EEI asserts that: (1) the term of a POLR's contract with a QF should not exceed the length of the competitive solicitation processes, which are for one year or less; (ii) the pricing should be set by the competitive solicitation process or some similar alternative; and (iii) the amount of energy or capacity sold by the QF must be limited so that the POLR is not required to purchase more than needed to serve its expected load.

EEI believes that "[f]orecasted avoided cost mechanisms are obsolete in a day of open access transmission and robust bilateral and organized market trading." EEI assumes that going forward, due to the increase in resources with zero-cost fuel, it is likely that energy prices will decline over time. In order for the prices paid by utility customers to remain neutral with respect to the pricing of QF energy, EEI believes it essential that FERC's rules for setting avoided cost rates not lock in prices that are likely to be above-market in the future. Accordingly, QF energy payments should be determined at time of delivery and not based on long-term projections. Additionally, FERC should permit state commissions to establish avoided cost at an appropriate competitive mechanism for procurement of such resources. Resources, otherwise eligible for qualifying facility status, may participate in requests for proposals that set the clearing price for such resources. The determination of avoided cost should be market based, including alternatives such as locational marginal price at the time of delivery; the clearing price in a request for proposals, allowing the contract to adjust to incorporate the most recent clearing price; a formula rate where only the formula is fixed at the time the obligation is incurred such that the specific energy and/or capacity avoided cost may fluctuate over the term of the obligation; or a liquid hub price, such as the Mid-C or Palo Verde, provided at the time of delivery.

To implement these changes, EEI specifically proposes the following amendments to §292.304 of FERC's regulations ("Rates for Purchase"):

(d) Purchases "as available" or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy <u>and</u> or capacity pursuant to a legally enforceable obligation for the delivery of energy <u>and</u> or capacity over a specified term, in which case the <u>energy</u> rates for such purchases <u>shall be no higher than the purchasing utility's avoided costs calculated at the time of delivery and the capacity rates for such purchases shall</u>, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided <u>capacity</u> costs, <u>if any</u>, calculated at the time of delivery; or
(ii) The avoided <u>capacity</u> costs, <u>if any</u>, calculated at the time the obligation is incurred, <u>but not more than 12 months prior to the time of delivery</u>.

(3) <u>The right to a legally enforceable obligation shall not arise until such time as the qualifying facility has demonstrated that its project is viable pursuant to criteria established by the State regulatory authority or nonregulated electric utility</u>.

. . . .

(e)(5) <u>The extent to which a utility has been relieved of an obligation to serve load under state law, the avoided costs of energy and capacity that might be provided by a qualifying facility may be set at $0 (zero dollars).</u>

"Gaming" of the one-mile rule.

FERC should establish a qualitative rather than a bright line test. Specifically, EEI proposes that FERC revise its one-mile rule to clarify that all generating sources using a common point of interconnection should be considered a single facility and for facilities located greater than one mile from the facility for which qualification is sought change the one-mile rule from an irrebuttable to a rebuttable presumption that the facilities are separate facilities for the purposes of qualification

The 20 MW threshold for the mandatory purchase obligation in the organized markets.

FERC's existing regulations establish a rebuttal presumption that small generators (20 MWs or less) do not have nondiscriminatory access to wholesale markets for the sale of energy and capacity. The burden of proof to refute that is on the utility or other protestors. EEI proposes that the 20MW threshold should be eliminated or significantly reduced. EEI believes that the question of whether a QF has "nondiscriminatory access" to a market should focus on just that – whether the QF meets the applicable minimum participation rules in the applicable region. This will place the smaller renewable and cogeneration resources on the same non-discriminatory basis as energy storage, demand response aggregators, and other small generators in the RTO/ISO markets. In addition, EEI asserts that as resource diversity has improved and the markets have evolved, the RTO/ISO markets have increasingly adjusted their bidding rules, forecasting, and operations to better accommodate the use of variable resources

Self-certification.

FERC's regulations make certification of qualifying facilities automatic and put the burden on protestors to pay for any objection to a questionable certification. EEI proposes to require any QF to certify that it meets the requirements of the regulations, requiring any interested party to protest the certification, and shift the burden of proof to the QF.

On July 13, 2018, a coalition of industrials led by ELCON submitted its own set of supplemental comments that responded to EEI. The comments addressed avoided cost, establishment of a legally enforceable obligation, the 20-MW threshold, and self-certification. The comments concluded that the Commission should deny suggestions that a holistic review of its FERC regulations is necessary or appropriate, as wholesale changes would be inconsistent with the Congressional intent underlying PURPA with the outcomes of recent Congressional hearings on PURPA implementation and potential reforms, and with the testimony and statements provided at FERC's 2016 technical conference in this docket. Instead, the Commission should limit its PURPA inquiry to narrow, targeted fixes that may warrant review, such as reassessment of the one mile rule and correction of the over-saturation of renewable qualifying facilities in certain states.

On July 20, 2018, NARUC submitted supplemental comments that reiterated its prior positions. NARUC seeks (i) expansion of the "comparable competitive quality" exclusion so that utilities outside of the seven RTO/ISOs could be eligible (and proposes various yardsticks and procedures to implement its proposal), (ii) lowering or eliminating the 20 MW threshold, such as to whatever the minimum capacity requirement is for a resource to participate in an

RTO/ISO, and (iii) address the "disaggregation problem" -- incidents where projects have forgone economies of scale to qualify themselves as individual QFs and evade other regulations.

More recently, additional supplemental comments have been filed. The Solar Energy Industries Association filed strong supplemental comments supporting PURPA including maintaining the 20 MW threshold, the self-certification procedures, the current definition of wholesale markets and a bright line test if there are any changes to the one-mile rule. SEIA commented that steps to "modernize" implementation of PURPA could include adoption of a rebuttable presumption that PURPA PPAs must have a term of at least 20 years, a requirement that state commissions adopt standardized PPAs, and adoption of a uniform standard for establishing a legally enforceable obligation. Notably, SEIA encourages that the Commission adopt ELCON's suggestion and draft avoided cost guidance for use by state commissions and utilities. Covanta filed supplemental comments presenting a specific example of discriminatory treatment of a waste-to-energy facility in Michigan that was subject to unreasonably low avoided cost payments and an unreasonably short, year-to-year PPA term. The Southern Environmental Law Center and other groups also filed supplemental comments supporting PURPA as "critical" for encouragement of small independent power production. The comments requested that the Commission conduct a "robust 50-state survey" to determine where PURPA implementation has been inadequate, to investigate existing barriers, and to evaluate opportunities to strengthen PURPA implementation. They noted as a key barrier that QF developers "are unable to obtain long-term contracts at forecasted rates." NARUC, on the other hand, filed another in its series of supplemental comments, this time submitting a white paper proposing that FERC exempt from the mandatory purchase obligation those utilities that are subject to state competitive solicitation requirements and other best practices that provide "technologies that qualify as QFs with a meaningful opportunity to sell their output." NARUC asks the Commission to "create a yardstick of characteristics that describe in detail how a utility could qualify for an exemption" and makes a number of specific suggestions for criteria that could be included in the yardstick.

AF&PA and ELCON submitted joint supplemental comments providing data and argument to support their views that PURPA is not the cause of any perceived overcapacity of renewable resources, industrial CHP does not contribute to overcapacity, and CHP continues to face discriminatory utility behavior. Accordingly, the associations recommended that FERC should continue to encourage industrial QFs and especially CHP, should provide states additional guidance regarding avoided cost calculations, and should make only limited modifications to its regulations.

The Global Energy Institute, an affiliate of the US Chamber of Commerce, encouraged FERC to engage in a holistic review of PURPA and to promptly issue a NOPR as in its view PURPA is now subsidizing QFs "at the expense of lower electric customer rates." The group highlighted avoided cost based rates far in excess of market rates and alleged abuses of the one-mile rule.

FERC action remains pending.

Background

On June 29, 2016, FERC held a Technical Conference on issues relating to PURPA implementation. The first panel addressed issues relating to the mandatory purchase obligation, including: the Section 210(m) rebuttable presumption and the barriers to access encountered by QFs of 20 MW and below; when a QF can be curtailed; the impact of utility contracting and interconnection practices on QF transactions; the obligation to purchase "as available" power; the obligation to sell supplemental, standby, backup and maintenance power to a QF; the obligation to purchase pursuant to legally enforceable obligations, particularly as these issues arise in new and emerging markets; and the impact the emerging energy imbalance market in the West may have on the mandatory purchase obligation. The second panel addressed avoided cost calculation issues, including: the assumptions and analyses that are used to develop avoided cost prices; whether and how various pricing methodologies are consistent with PURPA; the strengths and weaknesses of different avoided cost pricing methodologies; potential improvements to current pricing methodologies; whether an avoided cost methodology may reflect the locational and/or time value of QF output; the role of wholesale market revenues in developing avoided cost calculations; and methodologies for the determination of avoided costs for capacity and for long and short-term arrangements. ELCON participated on this panel. For those interested, FERC has posted a transcript of the technical conference.

On September 6, 2016, FERC issued a notice inviting post technical conference comments on two matters: (1) the use of the "one-mile rule" to determine the size of an entity seeking certification as a small power production QF; and (2) minimum standards for PURPA-purchase contracts.

About 40 comments were filed by the November 7, 2016 deadline. ELCON's comments promoted continued full implementation and enforcement of PURPA's mandatory purchase obligations. Similar points were made by AF&PA, Southern Environmental Law Center, IECA, various state and regional groups, and by renewable and independent producer interests including AWEA, SEIA, NewSun Energy, the Northwest & Intermountain Power Producers Association, the Renewable Energy Coalition, Covanta Energy, EDP Renewables, Community Renewable Energy Association, Allco Renewable Energy, California Cogeneration Council, LS Power. On the other hand utility interests naturally sought further erosion of PURPA's protections through, for example, watering down of the one mile rule, further "flexibility" in contract terms, and reducing the 20 MW threshold. Utility interests filing comments included EEI, NRECA, Arizona Public Service Co., Southern Co., Alliant Energy, Xcel Energy, Duke Energy, Berkshire Hathaway Energy, The comments of API supported some of the points made in the comments by the utility groups. NARUC's comments appeared to offer some support for PURPA while seeking additional state flexibility to balance just and reasonable ratemaking with promoting QF development.

E. Technical Conference on Competitive Transmission Development Rate Issues (Docket No. AD16-18)

On June 28 and 29, 2016, FERC held a Technical Conference on issues relating to competitive transmission development processes, including use of cost containment provisions, the relationship of competitive transmission development to transmission incentives, and other ratemaking issues. The two day conference had five panels:

- Cost containment provisions in competitive transmission development processes (i.e., the ITC petition issue discussed in the prior edition of this memorandum).
- Commission consideration of rates that contain cost containment provisions and result from competitive transmission development processes (ELCON participated on this panel).
- Transmission incentives and competitive transmission development processes.
- Interregional transmission coordination issues.
- Regional transmission planning and other transmission development issues.

For those interested, FERC has posted a transcript of the technical conference.

On August 3, 2016, FERC issued a notice inviting post technical conference comments on a series of questions raised for each of the five panels. For example, for the panel in which ELCON participated, the questions are:

> 1. Should the Commission have a role in evaluating the rate-related components of competing proposals for transmission facilities eligible to be selected in a regional transmission plan for purposes of cost allocation (e.g., terms of cost containment provisions, rate of return, transmission incentives) before the public utility transmission providers in a region select a proposal? If so, what role? What steps could the Commission take to prevent such a role from creating undue delays in transmission planning processes?
>
> 2. What types of performance-based rates could the Commission accept to reduce asymmetrical risk?
>
> 3. The Commission has accepted proposals to allow incumbent and non-incumbent transmission developers to recover, under certain circumstances, costs associated with developing transmission projects that are proposed but not selected in a regional transmission plan for purposes of cost allocation. Should the Commission reexamine, in general, whether such costs may be recovered?
>
> 4. Which entities should monitor, verify, and/or enforce compliance with cost containment provisions of selected transmission facilities? What are effective ways for them to do so and what are the advantages and disadvantages of different

approaches?

About 60 comments were filed by the October 3, 2016 deadline. ELCON's comments expressing concerns about artificial incentives, risk mitigation and consequent overbuilding of transmission received considerable play in the trade press. More generally, the comments reflected a lack of consensus on how to revise Order 1000, if at all. The comments by EEI and renewable groups comments emphasized a need to retain flexibility (in the latter case with coordination among neighboring regions), whereas TAPs supported partially standardized cost-containment provisions.

In lengthy comments, APPA and NRECA made the following points:

- APPA/NRECA support allowing bidders to include cost containment commitments in their bids. Care must be taken to ensure that any caveats or carve-outs in such commitments do not unnecessarily reduce, or even negate, the ratepayer benefits of the cost containment commitments. Maximum transparency in the bid and bid evaluation process should be required.
- Project developers and their shareholders should shoulder any incidental risk stemming from their voluntary decision to participate in a given competitive solicitation. The Commission should strictly limit the circumstances under which the costs associated with developing transmission projects that are proposed, but not selected, in a regional transmission plan are recoverable.
- There has been no showing that the Commission's current practice of deciding, on a case-by-case basis, whether a given incentive should be applied to a given public utility or project is inefficient or is not working. Thus, the Commission should maintain its current practice.

- There is no basis to conclude that there has been a lack of development of interregional transmission facilities.
- APPA/NRECA strongly oppose any change to the DCF methodology for nonincumbent transmission developers. There has simply been no showing that such changes are warranted or appropriate.

On July 2, 2018, the House Subcommittee on Energy sent a letter to the Commissioners updates regarding its reconsideration of Order No. 1000 given that two years has passed since the Technical Conference. The letter focused on lack of competitive transmission development and problems with developing transmission between planning regions, as was raised by witnesses in a May 4, 2018 hearing before the Subcommittee.

Further FERC action including a response to the letter remains pending.

F. Technical Conference on State Policy Issues on Resources and Resource Attributes (Docket No. AD17-11)

On May 1-2, 2017, FERC held a technical conference on state initiatives impacting whole power markets in the eastern RTOs/ISOs. The notice stated:

> Because the wholesale competitive markets, as currently designed, select resources based on principles of operational and economic efficiency without specific regard to resource type, there is an open question of how the competitive wholesale markets, particularly in states or regions that restructured their retail electricity service, can select resources of interest to state policy makers while preserving the benefits of regional markets and economic resource selection.

The notice referenced discussions underway in the eastern RTOs/ISOs.

ELCON participated in the conference and separately has issued a report about the proceedings. The notice referenced FERC staff's five potential paths forward with respect to the interplay between state policy goals and the wholesale markets: (1) limited or no minimum offer price rule; (2) accommodation of state actions; (3) status quo; (4) pricing state policy choices; and (5) expanded minimum offer price rule. Comments were requested on these and other paths, particularly to address: "(1) any centralized wholesale market changes (at a conceptual level) that would need to accompany implementation of a particular approach; (2) the feasibility of implementation; (3) the implications for market participants' ability to make long-term decisions; and (4) the near-term and long-term sustainability." The notice also asked for comments on: (1) the principles and objectives that should guide the selection of a path forward; (2) the degree of urgency for reconciling wholesale markets and state policies; (3) long-term expectations regarding the relative roles of wholesale energy and capacity markets and state policies in the Eastern RTOs/ISOs in shaping the quantity and composition of resources needed; and (4) procedural steps that the Commission should take, if any, to reconcile the competitive market framework with the increasing interest by states to support particular resources.

In its post conference comments, ELCON argued that only Path 3—the *status quo*—is tenable. Threshold legal issues are pending before the courts, and the resolution of these issues should be allowed to play out before any further action is taken at the federal level. Under the status quo, the principles of Order No. 2000 remain in full force. ELCON's position is to preserve the full competitiveness of the wholesale markets operated by the ISOs and RTOs—specifically in regard to their market-based, least-cost operation, and ELCON strongly urged the Commission to reaffirm the principles that underlay the formation of the RTOs as stated in Order No. 2000. Each state should use the ISO/RTO platform as is, and tailor its policies to accommodate the market design. If a state wants to force its citizens to pay for higher, out-of-market costs (*e.g.*, off-shore wind farms or subsidies for uneconomic power plants), FERC must not allow an organized market to be used to socialize those costs or otherwise distort those markets. States may resort to other methods of cost recovery that do not interfere with the competitive pricing mechanisms and technology neutrality of the organized markets.

In a memorandum to ELCON members dated June 29, 2017, ELCON staff summarized the numerous other comments that were submitted and noted that Paths 2 and 4 garnered the most supported. See that memorandum for further details.

This has become one of the more active dockets in recent memory; more than 100 comments were filed after the conference. However, FERC is unlikely to take on the matter in the near future, as even when the Commission again has a quorum, these sort of policy issues are likely to take a back burner to more pressing matters.

On March 6, 2018, ELCON and a number of other signatories submitted a filing to this docket expressing support for implementation of the following principles of market design:

1. Wholesale tariffs and market rules should be technology-neutral. All resource and technology types should have the opportunity to offer the services that they can provide and are needed to ensure grid reliability and (if appropriately defined and measured) resilience, and should be compensated for the value of such services. The wholesale market rules should not establish discriminatory criteria that provide an advantage to certain types of resources or technologies relative to other types of resources or technologies that are providing the same services.

2. Wholesale market rules should respect state and locally governed utility policies and resource choices without making customers pay twice for the same service. "Accommodating" state and local utility policies by forcing customers to pay once for the capacity obtained pursuant to state and local policies and again for resources allowed to clear in wholesale markets does not result in just and reasonable rates.

3. For true market competition to occur, wholesale customers and suppliers should be able to come together and transact as they choose through bilateral contracts. It is not the RTO/ISO's job to second-guess the resource and contracting decisions of eligible wholesale electric customers to buy or self-supply the types of resources and services they select, and for their chosen length of time. Long-term bilateral contracts can be beneficial for both wholesale customers and energy suppliers and should be fully accommodated inside and outside regions with organized markets. Bilateral contracts are a key part of competitive wholesale electricity markets, as they are in every other competitive sector of the economy.

4. Prices in the organized wholesale energy markets should be driven by market forces and provide appropriate compensation to dispatched resources for the value of the services they provide, including the support of grid reliability and (if appropriately defined and measured) resilience. Energy markets should not necessarily guarantee recovery of investment costs for particular resources or technologies. Investment cost risk should remain on investors and bilateral purchasers that commit to purchasing the output and benefit from the services being provided. Wholesale energy markets were designed to and are reasonably achieving their primary goal of efficiently dispatching existing resources.

5. Wholesale markets should benefit customers and reduce barriers to entry and exit. Markets should be allowed to function and stabilize before new solutions are deemed necessary to be implemented. Continual modifications of market structure and foundational rules should be avoided, as every market change could create new uncertainty and risk (which can result in increased costs for consumers).

Further FERC action is pending.

G. <u>SPP Exit Fees (Docket No. EL19-11)</u>

On November 2, 2018, the American Wind Energy Association and the Wind Coalition (AWEA) filed a complaint seeking a determination by FERC that the substantial exit fees imposed by the Southwest Power Pool (SPP) on members wishing to exit the RTO are "unlawful, unjust and unreasonable, and unduly discriminatory" and violate the cost-causation principle.

AWEA states that the exit fee that SPP would charge to a non-transmission owner or non-load-serving entity (non-TO/non-LSE) wishing to terminate its membership in SPP could range from $700,000 to $1 million. AWEA observes that SPP's exit fee is unique among the RTOs/ISOs and serves as a large barrier to non-TOs/no-LSEs to becoming members of SPP and fully participating in its stakeholder processes. This is starkly demonstrated by a comparison of the sizes of the voting member categories of the various RTOs/ISOs – in ISO-NE, MISO, and PJM, 71-82% of the voting members are non-TOs/non-LSEs, whereas in SPP only 22% of the voting members are non-TOs/non-LSEs. AWEA further notes that of the 96 current SPP members, only one could be considered primarily dedicated to represent interests "in demand response, distributed resources, environmental interests, consumer interests, and end users (industrial or otherwise)."

AWEA also makes a strong case that there is no cost causation because there is no connection between the exit fee and the financial impact of an exiting non-TO/non-LSE member on the cost of running SPP's business. AWEA notes that SPP, like the other RTOs/ISOs, collects an administrative fee to cover its incurred costs through transmission charges.

Twelve sets of comments by 23 entities supported the AWEA complaint. ELCON and TIEC filed joint comments noting that the SPP exit fee is an "insurmountable barrier"

to SPP membership and violates cost causation principles. Other comments supporting AWEA (and essentially reiterating in summary form the points made in its complaint) were filed by the Electric Power Supply Association, Solar RTO Association, Invenergy Energy Management, LLC, Interwest Energy Alliance, Solar Energy Industries Association, and a coalition of Public Interest Associations, among others.

Objections were filed by SPP and an ad hoc coalition of SPP transmission owners and other LSEs. The objections included that the complaint failed to provide sufficient support and evidence and failed to proffer a just and reasonable replacement rate, as required by FPA Section 206. On January 3, 2019, AWEA filed an answer seeking to rebut their assertions. AWEA also reiterated and expanded upon its arguments that the exit fee is not justified by region-specific circumstances, does not satisfy cost causation principles, and adversely impacts SPP's governance.

FERC action is pending.

H Revision to Horizontal Market Power Requirements (Docket No. RM19-2)

On December 20, 2018, FERC issued a NOPR to relax the horizontal market power filing requirements for sellers seeking to obtain or retain market based rate authority. In effect, the requirements to submit the horizontal market power indicative screens would be waived for sellers to the organized markets that administer energy, ancillary services and capacity markets subject to FERC-approved monitoring and mitigation. FERC essentially asserts that, in those markets, its adequate oversight adequately protects against exercise of market power. On the other and, sellers in CAISO and SPP would continue to be subject

to the requirement for any proposed sales of capacity (but not sales of energy and ancillary services only).

Comments are due 45 days after the NOPR is published in the *Federal Register*, which has been delayed by the government shutdown.

II. COURT PROCEEDINGS

A. *Village of Old Mill Creek and EPSA, et al. v. Star, et al., No. 17-2433 (Seventh Circuit)*

On September 13, 2018, a very short and unanimous decision by the Seventh Circuit upheld the Illinois Zero Emissions Credit ("ZEC") program, which was adopted in December 2016 to subsidize and avoid the shutdown of two Exelon nuclear plants. The court found that the Illinois ZEC program differed from the Maryland subsidy program that had been overturned by the Supreme Court in *Hughes v. Talen Energy Marketing* in that it was not tethered to a generator's wholesale market participation. In this regard, the court observed:

> To receive a credit, a firm must generate power, but how it sells that power is up to it. It can sell the power in an interstate auction but need not do so. It may choose instead to sell power through bilateral contracts with users (such as industrial plants) or local distribution companies that transmit the power to residences.

Further, although the outcome of PJM's auctions may affect the value of a credit,

> what (indeed, whether) a producer bids in the interstate auction does not determine the amount it receives. Every successful bidder in an interstate auction receives the price of the highest bid that clears the market. *Hughes*, 136 S. Ct. at 1293. The owner of a credit receives that market-clearing price, with none of the adjustments that Maryland law required. The zero-emissions credit system can influence the auction price only indirectly, by keeping active a generation facility that otherwise might close and by raising the costs that carbon-releasing producers incur to do business.

That the ZEC program could impact prices and require adjustments to the market does not change the outcome:

> Instead of deeming state systems such as Illinois' to be forbidden, the Commission has taken them as givens and set out to make the best of the situation they produce. . . . Those effects [on interstate sales] do not lead to preemption; they are instead an inevitable consequence of a system in which power is shared between state and national governments. Once the Commission reaches a final decision in the ongoing proceeding, the adequacy of its adjustments will be subject to judicial review; the need to make adjustments in light of states' exercise of their lawful powers does not diminish the scope of those powers.

On January 7, 2019, the EPSA coalition also filed a petition for certiorari of the Seventh Circuit decision before the Supreme Court. The essence of the petition is that the Court of Appeals adopted an overly narrow interpretation of the Supreme Court's prior decision in *Hughes* (which addressed the Maryland subsidy program) and that state subsidies that lack an express requirement for sales in wholesale markets but that, in effect and by design, subsidize only generators that sell their entire output via wholesale auctions also should be preempted. Supreme Court action is pending.

Background

On July 14, 2017, a federal district court judge issued a memorandum opinion dismissing challenges to the Illinois ZEC program. *Village of Old Mill Creek and EPSA, et al. v. Star*, Nos. 17 CV 1163, 1164 (N.D. Ill.).

The 43-page opinion addressed a number of issues, including procedurals hurdles -- the ability of private plaintiffs to directly pursue a private cause of action rather than first pursuing a complaint before FERC (presumably plaintiffs tried the former approach because it would not have been able to obtain a prompt FERC decision in the absence of a quorum of Commissioners) and the standing of plaintiffs to bring the action -- and Constitutional claims based on the Commerce Clause and Due Process Clause.

The core of the opinion, however, addressed whether the ZEC program is preempted by the Federal Power Act. Judge Shah concluded that there is no field preemption as "[t]he ZEC program falls within Illinois's reserved authority over generation facilities. Illinois has sufficiently separated ZECs from wholesale transactions such that the Federal Power Act does not pre-empt the state program." The key factors were that the ZEC program did not "impos[e] a condition directly on wholesale transactions" and that, contrary to plaintiffs' contention, a state law regulating generation is not preempted merely because it would affect -- even substantially -- the outcomes of the wholesale auctions. Further, there is no conflict preemption because there is no "'clear damage' to FERC's goals:" "FERC's power is undiminished" to respond to any "market distortion" resulting from the program and therefore to preserve "just and reasonable" rates.

The opinion distinguished the Illinois ZEC program from the Maryland subsidies that the Supreme Court found to encroach on FERC's jurisdiction in its April 2016 decision in *Hughes v. Talen*. Judge Shah concluded that the Illinois ZEC program had only an "indirect" effect on wholesale rates because it only "influenced the market by subsidizing a participant, without subsidizing the actual wholesale transaction." Specifically, under the Illinois program, generators can receive the ZECs even if they do not clear the capacity auction and even if they do not participate at all in the energy auction. Therefore, "[s]ince a generator can receive ZECs for producing electricity and the credits are not directly conditioned on clearing wholesale auctions, ZEC payments do not suffer from the 'fatal defect' in *Hughes*." By contrast, in *Hughes* Maryland had adopted a "contract for differences" subsidy that directly and improperly tied the generator's compensation to the capacity market price. Judge Shah emphasized that "[t]he qualifier 'direct" is important," and "*Hughes* should not be extended to invalidate state laws that do not include an express condition, but that in practice (and when combined with other market forces), have the effect of conditioning payment on clearing the wholesale auction."

The opinion also observed that ZECs are similar to renewable energy credits ("RECs") but there are no suggestions that RECs are preempted.

EPSA appealed to the decision to the U.S. Court of Appeals for the Seventh Circuit. EPSA's arguments against the Illinois ZEC subsidies were supported in briefs filed by: the Illinois Chamber of Commerce and the Illinois Industrial Energy Coalition; the American Petroleum Institute and the Natural Gas Supply Association; a group of "Energy Economists;" and the PJM Independent Market Monitor. AWEA submitted an amicus brief in support of neither party, making the point that if the court rules against the Illinois ZEC program, it should craft the scope of its decision narrowly as not to call wind subsidies into question. AWEA stated:

> [M]ost REC programs are market-based, not tied to the wholesale price of electricity, not tied to the economic viability of a resource, and can be traded across state lines. In contrast, ZECs are not market-based, are directly tied to wholesale energy prices (*i.e.*, based on wholesale energy price forecasts), are only available to otherwise uneconomic resources, and are limited to certain existing in-state resources.

Briefs supporting the Illinois ZEC were filed by the Illinois Power Agency, Exelon, The Nuclear Energy Institute, groups of economists, a group of other states, and environmental groups.

On January 3, 2018, the court heard oral argument. According to press reports, much of the argument focused on procedural issues surrounding whether case should have first been heard by FERC before proceeding to the courts. The Seventh Circuit required the parties to file supplemental memoranda addressing three issues: 1. Whether the court should defer to the Federal Energy Regulatory Commission's primary jurisdiction? 2. Whether *Ex Parte Young*, a 1908 Supreme Court decision allowing courts to hear claims that a state is acting unconstitutionally, is available as the basis of equitable relief in this case? 3. Whether the principle of *Illinois Brick Co. v. Illinois,* a 1977 Supreme Court decision, would prevent generators not directly affected by any higher prices resulting from the ZEC program and any others participating in this wholesale market from having standing to bring the case? The parties filed their responses on January 26, 2018. On February 21, 2018, the court issued an order inviting the United States to file an amicus brief expressing the views of the federal government.

On May 29, 2018, FERC and DOJ jointly filed the brief, taking the position that the Illinois ZEC program is not preempted by the Federal Power Act and does not improperly interfere with FERC's authority over the wholesale markets. The government's brief largely parallels the district court decision, emphasizing that unlike the overturned Maryland subsidies, the Illinois ZECs apply regardless of whether the nuclear plants clear the PJM auctions:

> Generators may receive ZECs even if they do not clear the capacity auctions conducted by the two FERC-jurisdictional market operators in Illinois. . . . . The ZECs are separate commodities that represent the environmental attributes of a particular form of power generation; they are not payments for, or otherwise bundled with, sales of energy or capacity at wholesale, and thereby fall outside of FERC's exclusive jurisdiction over wholesale transactions. . . . . And unlike the Maryland generator in Hughes, the . . . plants here are not limited to selling their output through the PJM auction. . . . . They may receive ZECs for production of zero-emission power, regardless of whether they opt to sell that power via wholesale auction, bilateral contracts, or directly to retail consumers.

Further, the government's brief asserted that if there is interference with the wholesale markets, it should be FERC and not the court that provides the remedy. Because the Commission has the statutory authority "to ameliorate, as needed, detrimental effects on markets within its jurisdiction" to assure just and reasonable prices, "the Court thus need not, and should not, resort here to the extraordinary and blunt remedy of preemption."

Finally, the government's brief summarized previous FERC decisions on state programs that support clean power. Respecting renewable energy credits ("RECs"), the brief asserts that "if the wholesale energy sale and REC sale take place as part of the same transaction, then the REC is a charge 'in connection with' a FERC-jurisdictional service that directly affects the rates for wholesale energy [and] [t]he Commission has jurisdiction over both portions of this 'bundled' transaction. . . . But RECs 'unbundled' from and independent of a wholesale energy transaction would not fall within the Commission's statutory jurisdiction." Similarly, state requirements that utilities purchase renewable generation or state loans, subsidies, or tax credits to particular facilities on environmental or policy grounds are permissible "so long as they neither set rates for wholesale sales of electric energy by public utilities nor set payment of rates to 'qualifying facilities' in excess of the purchasing utilities' avoided costs."

At FERC, the paper hearing in Docket Nos. EL16-49 and EL18-178 to address tariff revisions for new and existing resources that receive out-of-market payments had triggered hundreds of filings and remains pending.

B. *Coalition for Competitive Electricity, et al. v. Zibelman, No. 17-2654 (Second Circuit)*

On September 27, 2016, the U.S. Court of Appeals for the Second Circuit followed the Seventh Circuit and in a short decision unanimously upheld the New York Zero Emission Credit Program's subsidization of nuclear generation. In a decision very similar to the one just two weeks previously, the court found that there is no "impermissible tether" between New York's ZEC Program and participation in the wholesale markets and more generally no "clear damage" to federal goals – "[e]ven though the ZEC program exerts downward pressure on wholesale electricity rates, that incidental effect is insufficient to state a claim for field preemption" under the federal statute.

On January 7, 2019, the EPSA coalition also filed a petition for certiorari of the Second Circuit decision before the Supreme Court, as it did for the Seventh Circuit decision as discussed above. Supreme Court action is pending.

Background

On July 25, 2017, a federal district court judge issued a memorandum opinion dismissing challenges to the New York Zero Emissions Credit ("ZEC") program, which was adopted in August 2016 to subsidize and avoid the shutdown of the state's nuclear plants. *Coalition for Competitive Electricity, et al. v. Zibelman*, No. 16-CV-8164 (S.D.N.Y.). The decision follows, and adopts virtually identical reasoning to, the federal district court decision rejecting challenges to the similar Illinois ZEC program that was subject of our memorandum dated July 17, 2017. As was the case in the earlier decision, the heart of the 47-page opinion here addressed whether the ZEC program is preempted by the Federal Power Act, analyzing both "field" preemption and "conflict" preemption.[1]

Judge Caproni first concluded that there is no "field" preemption of the New York ZEC program by the Federal Power Act. This court's analysis also focused on the Supreme Court decision in *Hughes* and its recognition in overturning the Maryland subsidy program that States

[1] As Judge Caproni explained:

> State laws may be either "field" or "conflict" preempted. Field preemption exists where "Congress has forbidden the State to take action in the *field* that the federal statute pre-empts." *Oneok*, 135 S. Ct. at 1595. In such circumstances, "Congress may have intended to foreclose any state regulation in the *area*, irrespective of whether state law is consistent or inconsistent with federal standards." *Id.* Conflict preemption, by contrast, "exists where compliance with both state and federal law is impossible, or where the state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress." *Id*.

still may “encourage production of new or clean generation through measures ‘untethered to a generator’s wholesale market participation.’” Judge Caproni said that plaintiffs’ argument that the New York ZEC program is “tethered” to the wholesale auction “is no more than attempt to fashion a “tether” by jamming a square peg into a round hole.” Specifically, the court found that (1) state subsidies that prop up an otherwise unprofitable generator are not prohibited by *Hughes*; (2) under *Hughes*, what is impermissible is a tether to a generator’s “participation” in the wholesale market, not a state program’s incorporation of wholesale market price; and (3) there is no requirement that the nuclear generators sell into the wholesale market, rather the generators receive ZECs for their *production* of energy. By contrast, the invalidated program in *Hughes* “conditioned the generators’ receipt of a favorable rate (distinct from the auction rate) on the generators’ capacity clearing the auction . . . .”

According to the court, “[p]laintiffs’ argument commits the logical fallacy of concluding that state actions that affect the wholesale price in some way are the same as state actions that set the wholesale rate.” More than the earlier decision, this court focused on why other state incentives to generate clean energy such as tax exemptions, land grants and direct financial subsidies differ from the ZEC program, and it concluded that “[t]he death knell for Plaintiffs’ field preemption argument is their failure to distinguish ZECs from RECs.” “By establishing a program that does not condition or tether ZEC payments to wholesale auction participation, New York has successfully threaded the needle left by *Hughes* that allows States to adopt innovative programs to encourage the production of clean energy.”

The court also found no “conflict” preemption. The ZEC program does not thwart FERC’s goal of an efficient energy market as FERC has previously approved state programs with renewable portfolio mandates and greenhouse reduction goals. Moreover, indirect and incidental effects on wholesale prices "do not cause the sort of 'clear damage to federal goals,' . . . that would give rise to a claim of conflict preemption."

Finally, the court rejected plaintiffs' Commerce Clause argument that the ZEC program improperly discriminated against out of state generators that did not receive subsidies and imposed an undue burden on interstate commerce by distorting market pricing and incentives. The court found instead that the ZEC program "does not create a trade barrier or prevent or regulate the flow of energy . . . ." Judge Caproni cited a series of past decisions finding that the Commerce Clause does not require States to subsidize out of state businesses when in state residents are paying for the subsidies.

The decision is now on appeal to the U.S. Court of Appeals for the Second Circuit. The case was placed on an expedited calendar, and briefing is complete, with a list of participants similar to that in the Seventh Circuit case discussed above.

Oral argument was held on March 12, 2018. Press reports indicate that the three-judge panel seemed inclined to uphold the New York ZEC program, as unlike the Maryland subsidies that were invalidated by the Supreme Court decision in *Hughes*, New York ZECs are based on a forecast of wholesale market rates, and the subsidy is not conditional on completion of a wholesale market sale.

On August 30, 2017, as it did for the Illinois matter, EPSA filed a motion in Docket No. EL13-62 seeking FERC action to "act promptly to mitigate the harm from the [ZEC] program and other state initiatives that subsidize existing resources." Exelon and the New York Public Service Commission filed Answers to the Motion. **FERC action remains pending.**

W. Richard Bidstrup