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Statement

Of the

AMERICAN PUBLIC POWER ASSOCIATION

Submitted to the

HOUSE COMMITTEE ON ENERGY AND COMMERCE

SUBCOMMITTEE ON ENERGY AND POWER

For the December 1, 2015, hearing

"Oversight of the Federal Energy Regulatory Commission"

(Submitted December 15, 2015)

The American Public Power Association (APPA) appreciates the opportunity to submit this statement for the record in relation to the House Subcommittee on Energy and Power hearing "Oversight of the Federal Energy Regulatory Commission." The mission of the Federal Energy Regulatory Commission (FERC) is to "(a)ssist consumers in obtaining reliable, efficient and sustainable energy services at a reasonable cost through appropriate regulatory and market means."[1] This statement will focus primarily on whether FERC-approved wholesale electricity markets and, in particular, restructured wholesale electricity markets operated by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) (referred to collectively as "RTOs"), are efficient, provide energy services at a reasonable cost, and operate through appropriate regulations and markets.

APPA is the national service organization for the more than 2,000 not-for-profit, community-owned electric utilities in the U.S. Collectively, these utilities serve more than 48 million Americans in 49 states (all but Hawaii). APPA was created in 1940 as a nonprofit, non-partisan organization to advance the public policy interests of its members and their customers. We assist our members in providing reliable electric service at a reasonable price with appropriate environmental stewardship. Most public power utilities are owned by municipalities, with others owned by counties, public utility districts, and states. APPA members also include joint action agencies (state and regional entities formed by public power

[1] Federal Energy Regulatory Commission, Mission Statement (http://www.ferc.gov/about/about.asp)(last visited Dec. 10, 2015).

utilities to provide them wholesale power supply and other services) and state, regional, and local associations that have purposes similar to APPA.

Collectively, public power utilities deliver electricity to one of every seven electricity consumers. Public power utilities serve some of the nation's largest cities -- including Los Angeles, CA; San Antonio, TX; Austin, TX; Jacksonville, FL; and Memphis, TN. But most public power utilities serve communities of 10,000 people or less, such as the Green Island (NY) Power Authority (with 1,627 customers), the city of South Haven (MI)(with 9,052 customers), the village of Ludlow, VT (with 3,614 customers), and the Benton (KY) Electric Plant Board (with 4,844 customers).

Public power utilities produce roughly 10 percent of the electricity generated in the U.S. Annually, public power utilities generate roughly 170 million megawatt hours (MWhs) of electricity from coal (of 1,581 million MWhs generated from coal nationally); 77 million MWhs from natural gas (of 1,136 million MWhs generated from natural gas nationally); 63 million MWhs million from nuclear (of 789 million MWhs generated from nuclear nationally); 70 million MWhs from hydropower (of 263 million MWhs generated from hydropower nationally; and 8 million MWhs from other sources (of 276 million MWhs generated from other sources nationally) such as non- hydropower renewable energy like wind, solar, and geothermal. On the other hand, public power utilities supply approximately 15 percent of the electricity sold to end-users in the United States. To make up the difference between power generated and power sold, public power utilities purchase power at wholesale from other entities such as investor-owned utilities, independent power producers, rural electric cooperatives, federal power marketing administrations, and the Tennessee Valley Authority.

<u>FERC and Public Power</u>

Issues under FERC's purview directly affect the operations of public power utilities. Topics of particular interest to APPA in recent years have been: transmission planning, siting, and cost allocation; joint ownership of transmission facilities; increased use of incentive transmission rates; regulation of energy market derivatives; exercise of generation market power, mergers and affiliate transactions; and the operation of wholesale electricity markets. As noted above, this statement will focus primarily on the latter and, in particular, on restructured wholesale electricity markets operated by RTOs.

Public power utilities operating within the geographical boundaries of an RTO may, in theory, operate independently from the RTO, but in reality are largely captive to the RTO. First, due to legal constraints and policy considerations, public power utilities tend *not* to be "long" on power: i.e., they tend to generate less power than their customers consume. For example, in 2014 sales to ultimate customers by public power utilities totaled 573 million MWhs, but power generation by public power utilities totaled 411 million MWhs. Second, for many of the same legal and policy reasons, public power utilities tend not to own transmission facilities other than those necessary to connect their own generation and distribution facilities. As a result, most public power utilities rely on the bulk power grid for transmission of electric power needed to meet some portion of their service obligations. In RTO regions, it is almost always the case that the owners of the transmission facilities upon which a public power utility relies are members of the RTO. In effect, the public power utility has no choice but to also become a customer of the RTO to obtain access to the bulk power transmission facilities under control of the RTO.

Hence, while public power utilities' participation in these markets may in theory be "voluntary," in practice it is not. With their participation effectively mandated and the RTO stakeholder processes in most regions heavily skewed toward the interests of large transmission and generation asset owners, many public power utilities' only choice is to work closely with Congress and FERC to seek needed reforms.

RTOs and Wholesale Electricity Markets

Under the Federal Power Act, an RTO is an entity with sufficient regional scope "to exercise operational or functional control of facilities used for the transmission of electric energy in interstate commerce; and…to ensure nondiscriminatory access to the facilities."[2] Through regulations and orders, FERC has broadened the role played by RTOs in ensuring the reliability of the grid – both in the short-term through dispatch of generation and in the longer term through ensuring that load-serving entities have sufficient resources are in place to serve expected electricity demand. As a result, RTO markets run not only real-time and day-ahead electric power markets, but in some cases, capacity markets which drive future resource decisions within their regions. (Capacity refers to a resource's ability to be ready to generate power or reduce demand at the command of the system operator.)

Many of the wholesale electricity markets that FERC has authorized are not in fact markets as that term is popularly used. Rather, they are highly complex administrative constructs with a myriad of applicable rules, which change with alarming frequency. APPA's concerns about RTO-operated markets include: extensive and frequently changing rules; volatile prices, which can rise to very high levels; and limited data transparency. Adding to APPA's concerns are the complex, time-consuming and resource intensive stakeholder processes and the lack of transparency in the governance processes of some of the RTOs. We also are concerned about FERC's apparent failure to consider the cumulative impact on customers – including residential, commercial, industrial, and institutional customers – of RTO market outcomes, stakeholder processes, and governance.

In certain RTOs, the stakeholder process is part of the problem that electric consumers and their representatives face. For-profit owners of substantial generation and transmission assets exercise substantial influence in some RTOs' stakeholder processes. These asset owners can, and in some cases have, shifted control of their assets from one RTO region to another (for example, leaving the Midcontinent Independent System Operator and joining the PJM Interconnection LLC) to maximize their financial returns on those assets. This threat has the practical effect of making RTOs very responsive to these entities' concerns. Other RTO participants, including smaller utilities embedded in the transmission systems of these large asset owners, do not have comparable tools to use to influence RTO market policy.

Moreover, large asset owners simply have more people and resources to devote to the stakeholder

[2] Federal Power Act, Section 3(27) (16 USC 793(27)).

processes. Given the large number of work groups, task forces, and committees that each RTO sponsors, it is simply harder for customer-side representatives to attend and participate in all relevant meetings, and to evaluate and understand the impacts of the proposals being made.

The most problematic of the RTO-operated markets are the capacity markets, and specifically the mandatory capacity markets that are operated by the RTOs in the East (the PJM Interconnection, ISO New England and parts of the New York ISO). These administrative constructs account for a substantial share of the total electricity costs consumers and businesses in these regions pay. Unfortunately for electric consumers, these mechanisms have not demonstrated that they can fully support a reliable and diverse supply of power and incent the building of new generation resources where they are most needed. Instead, these constructs have required consumers to pay billions of dollars in costs, with little concomitant benefit.

FERC says that the RTO capacity-market rules it has approved are “neutral” as to source of generation and so do not infringe on state-retained resource allocation authority. However, in some instances FERC-approved RTO market rules are so specific and so heavily weighted as to strongly bias the resource allocation outcome, i.e., capacity performance requirements that are much more feasible for coal, natural gas, or nuclear power generation to meet.

APPA agrees there needs to be a certain level of base-load generation (i.e., power generation that can be available at full output for an extended period as needed by the system operator to ensure reliable operations). It is also important that, within the RTOs, there are sufficient resources that can generate power during emergencies and provide necessary support to the system, such as frequency and voltage support. But it is important to ensure that “properly valuing” such resources through the “markets” does not equate to imposing unnecessarily high costs on consumers by over-compensating such resources. In fact, FERC has *not* required RTOs to demonstrate whether the costs of the market rules are justified by the benefits, or whether certain goals, such as resource adequacy, could be achieved by alternative mechanisms at a lower cost to consumers. In recent years, both the ISO New England and the PJM Interconnection have proposed increasingly costly rule changes in the name of enhancing and assuring reliability. Ironically, these increased costs have been proposed to address the problem that capacity providers have not always been available during system peak times; *i.e*., despite having been paid in advance to provide capacity at all times. APPA agrees that such performance issues need to be addressed, but not with the costly and extensive rule changes these RTOs have proposed. Stakeholders sent Members of Congress in the PJM region a letter addressing one such proposal—PJM’s capacity performance proposal. The letter was signed by 14 public power utilities and associations (including APPA members), electric cooperatives, a group of large industrial customers, state commissions and consumer advocates. The letter explains that PJM’s capacity performance proposal “would dramatically increase electric costs without providing meaningful and necessary improvements in system reliability.”

Moreover, there is value in having a diverse fleet of resources. To the extent that RTO market rules over-compensate resources that can meet the criteria of providing continuous operation, such rules will discourage hydropower, non-hydropower renewables, and demand response. Yet those resources are valuable components of an electricity resource portfolio, especially if electric utilities are going to be required by the EPA to reduce the greenhouse gas emissions associated with their power supplies.

Another concern with the capacity markets is that the “classic,” and historically successful, way to finance capital intensive investments is through long- term bilateral contracts that support financing by providing assured cost recovery and a predictable revenue stream. However, this model has been upended in these mandatory capacity markets, overseen by FERC. In addition, because new supply development increases competition, the primary beneficiaries of the capacity markets – incumbent owners of older, less efficient power plants – have sought and received approval from FERC for the RTOs to implement rules that create impediments to new supply. These changes to the capacity market rules, known as Minimum Offer Price Rules (“MOPRs”) or “buyer-side mitigation,” administratively impose floor prices on such new generation, and have weakened the ability of the states to make decisions on their energy future and of public power utilities to fulfill their obligation to provide reliable electric power at the lowest reasonable cost. To further exacerbate the concerns of public power utilities and others, the buyer side “market power” that FERC is attempting to mitigate has never been demonstrated to exist.

When the capacity markets were implemented, public power and cooperative utilities and a number of states carefully negotiated provisions that exempted self-supply and state-procured resources from such buyer-side mitigation. Unfortunately, FERC has since chosen to ignore these negotiated settlements, and to remove such exemptions. As a result, these local utilities face the potential for double cost exposure – the cost to construct a plant and a potential additional cost to buy the same power from the market if the mitigated offer price does not “clear” the relevant capacity auction – making it much more difficult and costly to finance such new resources.

The incorporation of such “buyer-side market power” rules reflect APPA’s broader concern that FERC often accepts market proposals from the incumbent generation owners that are aimed at maintaining their revenues and reducing competition – the exact opposite of how a robust, competitive market functions, and a shift away from the mandate under the Federal Power Act for FERC to ensure that wholesale market rates are “just and reasonable.” When formulating its positions, FERC frequently ignores the lack of evidence that the restructured markets operated by RTOs are actually markets in the first place or that they have provided sufficient benefits to consumers and the economy. FERC should take a more critical and holistic view of these markets, and pursue fundamental reforms that reduce the adverse impact on reliability and electric consumers, including removing mandatory requirements for participation in these capacity markets.

APPA has long recommended that the Eastern RTOs’ mandatory capacity constructs be phased out and replaced with voluntary, residual capacity markets, with primary resource procurement achieved through a portfolio of long-, medium- and short-term contracts and a diverse resource mix. In the event such an overhaul is not undertaken, APPA would propose the following interim steps:

A) RTOs that have not yet implemented a mandatory capacity market should not move to do so without unanimous support by the states in the region; and

> B) RTOs that have already adopted a mandatory capacity market should not impair (through rates, or rules, regulations, or practices affecting rates) the ability of a load-serving entity to meet its capacity obligations through a resource it owns, builds, controls, or for which it has a contract for capacity.

These reforms would go far in accomplishing many of the criteria that APPA supports here – including just and reasonable rates to consumers, diverse resources, continued reliability, improved governance, and due consideration of state and local resource decisions.

Baseload Generation

There is no doubt that the electric power generation is undergoing a sea change. Incumbent generators, however, hope to retain and expand on current wholesale capacity market rules to shield themselves from these changes. They argue that Congress must act to protect existing generation, at any cost, to protect electric power reliability. That is not correct.

First, reliability is not an issue spontaneously created in 2015, but has been of concern to electric power utilities since their creation. In fact, roughly half of the nation's public power utilities have been in operation for a century or longer and nine out of 10 have been in operation for at least 50 years. Reliability of service is absolutely core to their success -- and public power utilities were meeting their reliability obligations long before the RTOs invented capacity markets.

Second, market rules designed to shore up baseload generation are unlikely to promote new generation or to rescue existing, but non-economic power plants. These new rules, however, have succeeded in providing billions of dollars of windfall profits to incumbent generators. For example, a study of auctions conducted in the wake of new PJM Interconnection "performance requirement" rules shows an increase in electric capacity prices of $7.3 billion over a three-year period for consumers in the Mid-Atlantic and Midwest states within the PJM Interconnection. But it is not clear whether there are any reliability benefits to justify these costs. For example, for the 2016/2017 delivery year, of the 95,097 MWs in cleared capacity, 90,850 MWs will be provided by resources that had already agreed to provide capacity in a prior auction at a lower price. Likewise, for the 2017/2018 delivery year, of the 112,000 of capacity cleared, 102,000 will be provided by resources that had already agreed to provide capacity in a prior auction at a lower price.

APPA understands the need to keep coal and nuclear power as part of a diverse fuel generation portfolio. However, the owners of such units should look outside RTOs, not inside RTOs, for the model for success. Three-quarters of the new coal plants completed in the past four years and all of the new nuclear plants recently completed or in progress have public power and/or rural electric cooperative utility funding under long-term agreements.

Five nuclear plants with capacity totaling 4,800 megawatts have retired or are scheduled for retirement. This includes the retirement of the San Onofre Nuclear Generating Station, Kewaunee Power Station, Crystal River Nuclear Plant, and Vermont Yankee Nuclear Power Plant, and the scheduled retirement of Oyster Creek Nuclear Generating Station at the end of 2019. Four of these five plants are located in regional transmission organizations (RTOs) and two are in RTOs with the highly problematic mandatory capacity markets.

Another six plants have been publicly discussed by the owners as under the threat of retirement. All of these plants are located within RTOs, and four are in RTOs with mandatory capacity markets. They include Ginna Nuclear Generating Station, Byron Nuclear Generating Station, Clinton Nuclear Generating Station, Quad Cities Generating Station, the Fitzpatrick Nuclear Power Plant, and Davis-Besse Nuclear Power Station. Owners of these merchant plants are seeking supplemental revenue streams to be paid by ratepayers in addition to the payments received from RTO markets.

Conversely, of the five new nuclear reactors currently being developed at three sites, none are located within RTOs. These include Watts Bar Unit 3 at the Watts Bar Nuclear Plant, Vogtle 3 and Vogtle 4 at the Vogtle Electric Generating Plant, and VC Summer 2 and VC Summer 3 at the Virgil C. Summer Nuclear Generation Station. These new units will provide a total of 5,800 MW of capacity (about 5.5 percent of the nation's 104,000 in nuclear powered capacity. And, all have a large share of public power ownership and financing.

Over the past few years, as low natural gas prices have contributed to reduced earnings by nuclear generation and several plants have retired, owners of merchant nuclear capacity have been advocating for changes to the RTO-operated electricity markets to ensure that such facilities are "properly valued" by the markets. Essentially, these owners are asking for prices to be adjusted to reflect the value of certain attributes of nuclear power, such as its lack of emissions and round-the-clock electricity delivery. One area of recent activity by FERC involves price formation in the wholesale energy markets, as noted by FERC Chairman Norman Bay in response to questions in this hearing about retiring baseload facilities. Thus far, FERC activity in this arena has largely been confined to information gathering, although a recent proposal by FERC would increase the number of short-term electricity price spikes. APPA is concerned that while such market changes may increase the revenue earned by nuclear and coal plants, the lack of a careful approach to price formation may also produce windfall earnings for many generators that are not in danger of retirement and also impose excess costs on the economy. A much more targeted approach, employing bilateral contracts, is a better way to preserve needed baseload generation without excessive costs.