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Hearing on
Oversight of the Federal Energy Regulatory Commission

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Chairman Murkowski, Ranking Member Cantwell, and members of the Committee:

My name is Cheryl LaFleur, and I am honored to appear before you today as a Commissioner at the Federal Energy Regulatory Commission (FERC or Commission). I have been at the Commission for nearly eight years now, and have appeared before the Committee several times. I am happy to do so today as part of a full Commission.

During my tenure at the Commission, much of our work has been driven by the biggest energy story of the past decade: the ongoing transformation in our nation's power supply. We are experiencing a significant increase in our reliance on natural gas for electric generation, due primarily to the increased availability and affordability of domestic natural gas, but also to the relative environmental advantages of natural gas and its role in balancing the growing fleet of variable resources. There is also considerable growth in renewable, storage, and demand-side resources, driven by changes in technology, economics, and policy. These new resources have different costs, operational characteristics and geographic characteristics that are impacting the nation's markets and infrastructure. These transformative developments are not being driven by FERC but are shaping much of our work on markets, infrastructure (both natural gas and electric), and reliability standards. Today I will discuss two of these topics – our regulation of wholesale electricity markets and interstate transmission planning.

Wholesale Markets

I will address five aspects of our work on wholesale markets, all of which relate to the changing resource mix: (1) rulemakings the Commission has undertaken to enhance competition by ensuring that all technologies can fairly participate in the organized electricity markets; (2) market design changes to enhance price formation and improve resource performance during periods of system stress; (3) the expansion of organized electricity markets in the western U.S; (4) the increasing tension between FERC-jurisdictional electricity markets and state policies and (5) ongoing discussions around grid resilience.

The organized wholesale electricity markets that provide electric service to more than two-thirds of Americans are now roughly 20 years old. These markets arose from statutory and regulatory changes at the state and federal levels that were designed to promote greater competition in the electric sector. The hypothesis was that greater competition could yield substantial benefits for customers, and our years of experience with the markets have borne that out. Open and non-discriminatory access to the nation's transmission system has lowered barriers to entry, increased competition, and spurred innovation. Regional planning for, and deployment of, electricity supply resources has yielded substantial efficiency gains and cost savings, while the attraction of at-risk capital into these markets has successfully shifted much of the investment risk from captive customers to investors.

We have realized these benefits while allowing for different regional market structures that reflect varied state and regional prerogatives. Most notably, some regions rely upon mandatory capacity markets to procure an adequate supply of resources to provide reliable electric service to their customers. In other regions, resource adequacy remains the responsibility of individual states. A common feature across both market structures, however, is the use of competitive markets to price and deliver energy and ancillary services. This reflects the acknowledgment that deployment of available resources across a larger geographic footprint allows for more efficient utilization of those resources.

To increase competition and foster continued innovation in electricity markets, the Commission has worked over the years to ensure that market rules are fair to all technologies, including emerging technologies. These efforts include Order No. 764, which eased barriers to the incorporation of variable energy resources into the wholesale markets; Order No. 745, which addressed compensation for demand response resources; and Order No. 755, which required appropriate compensation for regulation service, including services provided by new resource technologies like energy storage. Most recently, the Commission in February issued Order No. 841 to address energy storage participation in wholesale markets, which Commissioner Glick will discuss.

In 2014, the Commission began an initiative to explore opportunities to improve price formation in energy markets operated by Regional Transmission Organizations, or "RTOs," and Independent System Operators, or "ISOs." The purpose of improved price formation is to send appropriate price signals to the marketplace as to what types of resources are needed by the system to deliver reliable service to customers, inform market participants where new resource entry may be necessary or beneficial, and provide information regarding when load should increase or curtail its energy consumption to minimize cost. To gather information on approaches to improve price formation, the Commission engaged stakeholders through a series of technical conferences. After consideration of that record, the Commission has taken a number of actions. We issued a final rule to align settlement intervals with dispatch intervals, and to require the triggering of shortage pricing during any operating interval when a shortage of reserves occurs. We also issued a final rule addressing energy offer caps to ensure that resources are sufficiently compensated for the costs incurred to serve load, particularly during tight system conditions. More recently, we directed certain RTOs and ISOs to modify their market rules to address concerns that certain fast-start resources are not able to set market clearing prices when they are called upon to help meet demand. Taken together, these changes will improve the ability of these markets to provide accurate prices that incentivize rational supplier and customer behavior and promote efficient investment decisions.

In addition to price formation, the Commission has also approved market design changes to incentivize reliable generator performance. In response to the changing resource mix and the increasing incidence of extreme weather events, grid operators are placing an emphasis on generator performance during times of system stress. The Commission has approved capacity market design changes in the ISO New England Inc. (ISO New England) and PJM Interconnection, L.L.C. (PJM) regions to address concerns that resources lacked strong incentives to perform reliably during these most critical operational periods. These changes use strong market incentives to signal to resource owners the importance of investing in and maintaining their resources so they are prepared to deliver energy during peak demand periods and when unforeseen system conditions arise.

Another area of development is the expansion of organized electricity markets across the country, reflecting the increasingly broad recognition of the benefits they provide. Since I joined FERC in 2010, entities in Mississippi, Louisiana, Arkansas, Texas, and Missouri have elected to join the Midcontinent Independent System Operator, Inc. and participate in its energy markets.[1] In 2015, entities in Iowa, Minnesota, Montana, North Dakota, South Dakota, and Wyoming opted to join the Southwest Power Pool, a grid operator and market administrator covering much of the central U.S. The Southwest Power Pool has also developed significant market enhancements in recent years, including adding a day-ahead market for energy and incorporating a price-based Operating Reserve Market.[2]

Today, we are seeing the expansion of markets in the Western U.S. The Western Energy Imbalance Market, operated by the California Independent System Operator Corporation (California ISO), has expanded in recent years to include utilities in Nevada, Arizona, Washington, Oregon, Idaho, and British Columbia. Additional utilities in California, Arizona, and Washington are slated to join by 2020.[3] The Western Energy Imbalance Market allows for trading of energy among participating entities so they can adjust to changing supply and demand in real-time by efficiently dispatching the entities' collective resources across utility and state boundaries. The result is greater grid reliability at lower costs, a value proposition that is incentivizing more Western entities to consider joining the Energy Imbalance Market. The California ISO has also announced plans to offer day-ahead energy market services to its Energy Imbalance Market participants, a development that could drive additional cost savings for Western customers. In addition, a group of electricity service providers in the Mountain West states, known as the Mountain West Transmission Group, is exploring joining the Southwest Power Pool.[4]

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[1] http://timeline.misomatters.org/
[2] https://spp.org/markets-operations/integrated-marketplace/
[3] https://www.westerneim.com/Pages/About/
[4] https://www.wapa.gov/newsroom/NewsReleases/2017/Pages/Mountain-West-SPP-negotiations.aspx

It is notable that these market expansions—both those that have been implemented and those now being contemplated—are being driven at the regional, state, and municipal levels, not by FERC. I believe this speaks to the increasingly broad recognition that sharing resources over a larger footprint can save money for customers by optimizing the use of existing generation and transmission assets and promoting greater competition in the development of new electric infrastructure.

Another issue the Commission has focused on extensively in recent years is the interplay between FERC-jurisdictional markets and state policies. Regions in the eastern U.S. that deregulated their generation years ago rely on FERC-jurisdictional capacity markets to ensure resource adequacy. Recently, however, rather than relying solely on the capacity market to select resources, states are enacting policies to procure a portion of their generation needs outside of the market by mandating bilateral contracting between a state's load-serving utilities and resource developers or owners. The result is a tension between state initiatives and the operation of the capacity market on which grid operators and the Commission rely to satisfy their resource adequacy responsibilities. In May 2017, the Commission held a two-day technical conference to closely examine the interplay of competitive wholesale markets and state policy initiatives, and to consider how ISO New England, the New York Independent System Operator Inc. (New York ISO), and PJM, each of which relies on a mandatory centralized capacity market for resource adequacy, should approach it. At that technical conference, I strongly encouraged those RTOs and ISOs to develop market design proposals to either accommodate or achieve state policy initiatives through forward-looking market reforms. To date, ISO New England and PJM have submitted regional market reforms for the Commission's consideration, and the New York ISO is evaluating carbon pricing reforms to help harmonize state climate policy with the markets.

I am a strong supporter of wholesale capacity markets, which I believe have delivered substantial benefits to customers through regional resource selection and deployment, protecting reliability at least cost, and promoting innovation and efficiency. At the same time, I recognize that these markets exist due to the decisions of the states to change the structure of their regulated utilities, leading the regions to rely upon mandatory centralized capacity markets to sustain resource adequacy and reliability. And as I noted earlier, clean energy policies set by individual states to address climate change and other environmental goals are a key driver of the ongoing transformation in the resource mix. Figuring out how to reconcile potential conflicts between state policy and the wholesale markets is therefore critical to the success of both.

While this is a challenging issue, I believe it is important that we allow for tailored regional solutions that seek to adapt wholesale market rules in order to preserve the benefits customers have derived from those markets while also respecting state policy choices to the extent practicable. Indeed, I believe a proposal from ISO New England that the Commission recently approved is an example of how the Commission can constructively address this tension moving forward.

Finally, our oversight of wholesale electricity markets also bears on our work on resilience. The Commission has taken a number of actions in recent years to address grid resilience, including some of the market reforms mentioned above. The current debate regarding grid resilience focuses on whether the continued retirement of certain uneconomic coal and nuclear generating facilities threaten grid resilience. To date, we have successfully managed the transition in the resource mix without compromising reliability, and I am confident that we can continue to manage that transition going forward. Indeed, the resource turnover we are experiencing is an expected consequence of markets, and the lower prices that result from wellfunctioning markets are a benefit to customers, not a problem to be solved, unless reliability is compromised.

However, as with states' increased focus on selecting resources outside the market, much of the discussion around grid resilience stems from concerns about the resources being selected by the wholesale electricity markets, which are increasingly low or zero marginal cost resources with different cost patterns and operational characteristics than conventional resources like nuclear and coal. The Commission is currently considering the record developed in our pending resilience docket, which I expect will help us determine whether any Commission action is needed to adapt our market rules, reliability standards, transmission planning processes, or *pro forma* agreements to the changes occurring on the grid. Should we conclude such action is needed, I hope that, consistent with our longstanding practice, the Commission will define the customer need in a fuel-neutral way, and either allow the market to transparently price it or establish broad, fuel-neutral requirements to ensure that a needed service is provided.

Interstate Transmission Planning

Under the Federal Power Act, the Commission has the authority to regulate wholesale interstate rates and interstate transmission service.[5] In recent years, transmission spending has increased; in 2016, utilities located in regional transmission organization and independent system operator regions spent about $21 billion on capital additions.[6] The primary drivers of these investments include system upgrades and replacement of aging transmission infrastructure, improving grid security, system hardening to minimize the adverse impacts of catastrophic events, and the continued development of geographically-constrained renewable resources.

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[5] 16 U.S.C. § 824 (2017).
[6] U.S. Energy Information Administration, *Utilities continue to increase spending on transmission infrastructure* (Feb. 2018), https://www.eia.gov/todayinenergy/detail.php?id=34892.

In light of the changes occurring in the electric industry, and based on the Commission's experience in implementing Order No. 890, in July 2011 the Commission issued Order No. 1000. Order No. 1000 was intended to ensure that the transmission planning and cost allocation requirements of Order No. 890 continued to result in the provision of Commission-jurisdictional service at rates, terms and conditions that are just, reasonable, and not unduly discriminatory or preferential. Building on the nine planning principles in Order No. 890,[7] Order No. 1000 requires each public utility transmission provider to participate in a regional transmission planning process and an interregional coordination process that each include an ex-ante cost allocation method. Order No. 1000 also introduced competition into the transmission planning process by requiring transmission planning regions to allow competitive bidding for certain regional transmission projects or needs.

Nearly seven years after the issuance of this landmark rule, the Commission has now approved all of the regional and interregional compliance filings. While many regions are still in the early stages of implementing their processes, the Commission continues to monitor each region's and pair of regions' Order No. 1000 processes. To date, five transmission planning regions have held competitive proposal windows to evaluate transmission projects or developers. In those five transmission planning regions, proposals by non-incumbent transmission developers, or joint proposals between incumbent and non-incumbent developers, have been selected for several projects. While I am encouraged by these results, I recognize that challenges remain, particularly with respect to the implementation of competitive processes for new regional transmission projects. I remain concerned that the threat of competition has, in some

[7] The planning principles identified in Order No. 890 include: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation.

regions, affected the transmission planning process as incumbents seek to shield transmission investment from competitive bidding. Unfortunately, these changes undermine two key goals of Order No. 1000 by discouraging regional transmission development and significantly reducing the benefits customers can receive from competitive bidding processes.

As part of the Commission's monitoring of Order No. 1000 processes, in June 2016 the Commission held a technical conference to explore competitive transmission development since the issuance of Order No. 1000. The topics explored during this two day technical conference included the following: an overview of each region's, or pair of regions', transmission planning processes and discussion of possible improvements; the use of cost containment provisions in the transmission development process and how the subsequent rate filings should be reviewed by the Commission; the interaction of competitive transmission development processes with the Commission's incentives policies, including transmission incentives and return on equity; and the status of interregional transmission development. In addition, the Commission issued transmission metrics reports in March 2016 and October 2017, which assessed transmission investment patterns, and Commission staff continues to monitor transmission planning region stakeholder meetings and actions concerning transmission development. As the Commission continues to work through the remaining policy issues that were delayed by the loss of quorum last year, I hope that we can act on the substantial record developed in the June 2016 technical conference to improve competitive bidding processes and better realize Order No. 1000's potential.