Written Testimony of Cheryl A. LaFleur
Commissioner
Federal Energy Regulatory Commission

Before the
Committee on Energy and Commerce
Subcommittee on Energy
United States House of Representatives

Hearing on
Oversight of the Federal Energy Regulatory Commission

June 12, 2019

Chairman Rush, Ranking Member Upton, Chairman Pallone, Ranking Member Walden, and Members of the Subcommittee:

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 nine years, and have appeared before the Subcommittee several times. Today, I will comment on three major issues that are shaping the Commission's work: (1) how individual states and regional electric markets select resources; (2) how those resources are compensated; and (3) how the Commission considers infrastructure decisions, particularly with respect to linear infrastructure like transmission lines and natural gas pipelines.

Wholesale Electric Power Markets and State Resource Decisions

In the twenty years since their creation, organized wholesale electric power markets have grown to serve over two-thirds of Americans. These markets save customers money by driving the efficient dispatch of resources over a large footprint, facilitate the introduction of innovative technologies and greater customer-side participation in the power supply, and, depending on the underlying state regulatory construct, shift investment risk from electricity customers to company shareholders. This committee has undoubtedly heard many concerns about the challenges currently facing the organized markets, particularly in the eastern half of the country. However, I think it is important to note that, those concerns notwithstanding, participation in organized markets continues to expand, with utilities and states in the West and Southeast exploring integration into existing organized markets or the creation of new regional markets. Whatever their challenges, the benefits of organized markets are very real.

Recently, perhaps because of the challenges faced by the eastern markets, there has been significant debate over whether power markets are "real" markets. Frankly, this debate concerns me, as I have observed it often occurs in conjunction with arguments favoring intervention on behalf of particular types of resources, at the expense of economic efficiency and therefore customer benefits. All markets require regulation in order to be fair and effective; however, the real-time nature of electricity, which requires the balancing of load and supply second by second, leads to a more complex market than many others, and requires more comprehensive regulation to ensure its proper function. I believe the Commission, as the entity that has led the development and expansion of competitive electricity markets, should continue to support the use of competitive markets for resource dispatch and procurement as a cost-effective way to meet customer needs.

A major challenge before the Commission and the electric industry more broadly is the issue of resource selection – specifically, to what extent organized markets, rather than individual states, will drive investment decisions for resource entry, retention, or retirement. This issue is complex, particularly in states that restructured their retail electricity supply, given the divided regulatory responsibilities among the states, the organized markets, and the Commission.

Since their inception roughly two decades ago, the organized markets have efficiently deployed resources to achieve reliability at lowest cost, while effectively managing the integration of new resources and the retirement of existing resources. For vertically-integrated utilities participating in those markets, the states retained and exercised control of resource adequacy, generally through their integrated resource planning work. For states that restructured their retail electricity supply, however, utilities generally divested their generation resources to either standalone or affiliated merchant power companies. Over time, the eastern markets – PJM Interconnection, L.L.C. (PJM), the New York Independent System Operator (NYISO), and ISO New England, Inc. (ISO-NE) – created capacity markets to ensure resource adequacy through forward procurement of commitments by new and existing resources. Driven by the collective impact of the energy, capacity, and ancillary services markets, the resource fleet in those regions has transitioned from units exclusively built prior to the existence of the power markets to a combination of new and existing resources largely selected by the markets.

In recent years, however, power markets generally have been roiled by low gas prices and by the build-out of renewables that have different cost, operating, and geographic characteristics than traditional fuel-based generation. These lower cost resources have significantly decreased wholesale power prices, to customers' benefit, but have also threatened the financial viability of certain traditional resources, particularly coal and nuclear plants. In response to these changes, many states have sought either to retain resources that are not thriving in the market, or to accelerate the resource change by supporting new resources that the market would not otherwise procure.

For the PJM, NYISO, and ISO-NE markets that have relied on centralized capacity markets to meet resource adequacy needs, these efforts have created tension between the operation of those markets and out-of-market support for particular resources. Notably, now that twenty years have passed since states restructured, the reasons that drove their decisions are before the professional memory and experience of many decision-makers. These efforts have triggered a debate over whether resource adequacy responsibilities in those regions are being, or should be, rebalanced towards greater state control, and how wholesale market designs should be adapted or overhauled in response.

In May of 2017, the Commission convened a two-day technical conference to discuss the intersection between state policies and wholesale electric power markets, including representatives from state commissions, regional market operators, and other stakeholders. In addition, regional market operators have been working to adapt market structures to accommodate state choices. For example, after the May 2017 technical conference, ISO-NE developed, and the Commission approved, the Competitive Auctions with Sponsored Policy Resources market reforms to balance state public policies with the competitive wholesale electricity market structures in the region. In addition, NYISO is currently considering ways to integrate carbon pricing into wholesale energy markets, which could provide an economically efficient way to incorporate state climate goals into the market structure. And, of course, the Commission has a significant open proceeding concerning proposed changes to the PJM capacity market.

Energy Pricing and Dispatch

The second major issue facing the Commission can be posed as a question: once we have selected the resources we need for the future – whether by market forces, integrated resource planning, or some combination – how do we price and dispatch them? Evidence from regions throughout the country, in organized markets and bilateral market regions, indicates that a fundamental shift in how we procure and pay for energy is underway.

Until recently, it was accepted without question that electric power was priced on volume, since a major component of cost was the commodity cost of the fuel burned to generate it. Baseload, intermediate, and peaking resources each played a well-understood role in helping to balance load. However, data in recent years suggest that cost curves, which traditionally have identified baseload resources as the cheapest and peaking resources as the most expensive, now look differently in many areas. With persistently low natural gas prices, zero marginal cost renewable resources, and distributed energy resources changing the shape of load curves, the traditional cost structures that supported resources may no longer provide appropriate compensation. We have seen this trend most famously in California, where solar resources generate so much energy in the middle of the day that the state sometimes exports power during its historic peak hours, and large hydroelectric facilities in the West spill water rather than generating electricity at a loss. Gas plants that previously provided significant amounts of energy during the day have seen their capacity factors fall, with more revenue now coming from meeting the evening ramp or for occasional peaks in energy demand. This trend is now starting to appear in other regions around the country.

The nation's more dynamic resource mix presents opportunities for significant customer benefits, but also presents new challenges. I believe that we can and must meet these challenges, rather than trying to preserve the resource mix of the past. To help adapt to the new resource mix, regional market operators and others are considering new ways of paying for power, with a focus on services instead of volume. This change is visible in the energy and ancillary services markets, with services such as flexible ramping products, scarcity pricing, new forms of reserves, and a greater attention to essential reliability services. In addition, some regions have revised their capacity markets to better ensure resource performance. The Commission and market operators have also taken steps to ensure that new resources, including storage, variable resources, demand response, and distributed energy resources, can compete to provide services that customers need. I expect that these efforts to evolve compensation structures and resource participation will continue to be a focus of the Commission's work in coming years.

Infrastructure

The final major issue I'd like to discuss also stems from changes in our nation's resource mix and our choices regarding how we generate electricity. Electric power markets are intended to signal when and where electricity is needed and, ideally, those signals translate into infrastructure decisions, including not just new generating facilities, but often the need for new transmission lines or natural gas pipeline capacity. However, when necessary infrastructure incentivized by market signals is not built, it impacts the market's ability to function as intended. There are real financial and reliability consequences to inaccurate or unrealized market signals.

Transmission is needed to facilitate the geographic spread of power generation, especially for location-constrained renewable resources. The Commission's issuance of Order No. 1000 in July of 2011 reflected and anticipated the growing need for regional and interregional transmission. I believe the planning and cost allocation tenets of Order No. 1000 are sound. However, the introduction of competitive transmission that it required has been slower and more difficult than anticipated and has arguably hurt transmission planning as incumbent transmission providers seek to invest in transmission projects not subject to the competitive processes required by Order No. 1000. While I am pleased to see many regions implementing their approved transmission planning processes, I recognize that challenges remain, particularly with respect to the implementation of competitive processes for new regional transmission projects.

In addition, the growth in domestic natural gas production and gas-fired electric generation has led to considerable buildout of the nation's gas pipeline network. I have called for reconsideration of how the Commission determines the need for pipelines to reflect market conditions and assess on a regional basis whether more infrastructure can be supported for these long-lived assets.

I also believe the Commission must do a better job of assessing and considering the climate impacts of gas pipelines and liquefied natural gas (LNG) projects. Before determining whether a proposed pipeline project is in the public interest under the Natural Gas Act (NGA), the Commission must disclose and consider the project's environmental impacts under the National Environmental Policy Act (NEPA). By comparison, for LNG projects, the Commission must find that the proposed LNG export facility is not inconsistent with the public interest under the Natural Gas Act, while the Department of Energy (DOE), not FERC, considers the public interest regarding the export of the gas itself.

Starting in 2016, responding to the growing debate showing up in our dockets, the Commission began disclosing more information on a project's climate impacts in our orders and in our environmental documents. I strongly supported this decision and believe it was a good place for the Commission to start a more robust assessment of the climate impacts of new gas infrastructure. However, in May of 2018, the Commission elected to remove much of the greenhouse gas (GHG) quantification and consideration from orders going forward. I disagree with this decision and continue to advocate that the Commission undertake robust climate analysis; specifically, quantifying, considering and assessing the significance of the direct, indirect, and cumulative GHG emissions from proposed projects.

Since June 2018, I have tried to reconcile my disagreement with the Commission's revised policy with my obligation to consider the merits of individual proposed pipelines under the NGA. Where I otherwise conclude that a pipeline is needed, I have done my own GHG calculation and analysis to weigh against the pipeline benefits and set out my thinking in separate concurring statements.

I will continue to consider and evaluate these issues as they arise in individual proceedings. However, I believe the Commission, the public, and the regulated community would be better served if the Commission proactively addressed these issues. If we do not, I expect that the courts, as they have already begun to do, will require the Commission to expand its climate analysis. Notably, any projects approved in the meantime will face significant legal risk that their certificates could be vacated.

I will continue to work to move forward on these issues as long as I am on the Commission, but that time is coming to an end later this year. It has been a tremendous honor to serve on the Commission and to work with this Committee. Thank you.