Speech by Commissioner Tony Clark
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Thank you for the invitation to be with you. My remarks today will focus on two broad themes, the first being a discussion of the role of financial participants in power markets. I will then discuss some of the issues FERC has been addressing under the theme of "proper price formation." Included will be a discussion of the challenges to price formation in FERC jurisdictional markets that I see coming around the corner.

So let's talk first about the role of financial participants in power markets. In FERC jurisdictional competitive wholesale electric power markets, financial participants, those who do not have the ability or desire to buy or sell physical electricity, play a unique role.

Traditional commodity markets include a clearly defined and delineated physical and financial market component. *Physical* commodity markets are inherently limited in size and participation by the ability to either deliver, or take possession of the underlying commodity. Physical transactions are price setting.

Traditional *financial* commodity markets, on the other hand, in which no good other than cash for differences is exchanged, are not price setting, settling off prices dictated within the physical market. Financial commodity markets are not limited in size by any factor other than the volume of willing counterparties. Financial commodity markets provide the liquidity, depth and price transparency needed to hedge physical supply and demand, while providing a broader vehicle for speculation and capital investment.

This clear delineation is greyed within the context of ISO/RTO competitive wholesale electric power markets, in which security constrained economic dispatch models are cleared using an auction process. Financial participants by bidding, or offering, virtual transactions or up-to-congestion transactions (UTC), which include no obligation to take or deliver physical power but are considered in the auction process, *can and do* affect physical prices. This is a unique outcome.

By affecting physical prices, financial participants in FERC jurisdictional competitive wholesale electric power markets can provide not only traditional 'financial' commodity market benefits, such as improved market efficiency, liquidity and depth, but can also improve 'physical' market outcomes. Improved physical market outcomes means spreads between Day-Ahead and Real-Time markets are tighter than they otherwise would be, and that overall wholesale market outcomes are more cost efficient.

Conversely, when abused, or used for manipulative purposes, financial participants in FERC jurisdictional electric power markets detrimentally affect not only financial participants, but physical market outcomes themselves. Distorted physical market outcomes mean spreads between day-ahead and real-time markets are wider than they otherwise would be, and that overall wholesale market cost outcomes are less efficient.

Add to that the fact that electricity is not like pork bellies; it is considered in many ways like a social good, necessary for the basic services of modern life, and it is no wonder why Congress, with the enactment of EPAct 2005, and FERC itself take issues of proper price formation and market manipulation so seriously.

As outlined in a recent report by PJM, "virtual trading benefits the efficient operation of the PJM energy markets. It can assist in attaining efficient market outcomes and improve commitment and price convergence between the Day-Ahead and Real-Time Markets. "

However, PJM states that "virtual transactions can have negative impacts on the market …Certain types of transaction activities, while profitable for traders, do not bring efficiency and may even degrade market operation. When used in certain ways, these transactions profit from the market without adding commensurate benefit, skew transmission flows and congestion patterns in a manner inconsistent with transmission system topology and load levels and, in large volumes, can significantly degrade the performance of the Day-Ahead Market."

Commenting on the unique nature of electric power markets, PJM states that "Price formation in…energy markets is not as straightforward as meeting bids with offers." An understatement if there ever was one, because these markets are very complex.

I would sum it up like this: Financial participants in FERC jurisdictional power markets provide the promise of expanded liquidity and depth, similar to their function in financial commodity markets, while simultaneously playing an important role in establishing physical wholesale market outcomes, similar in function to participants in physical commodity markets. For this balance to take place, appropriate rules must be in place to establish the correct risk and reward incentives for financial traders in competitive wholesale electric power markets.

This balance is reflected in the debate that is sometime had regarding whether FERC should enforce market manipulation only when very narrowly tailored, very specific rules have been violated, or whether FERC enforcement should also include prohibition of somewhat more general principles such as the guidance that traders are not permitted to make trades that are uneconomic in and of themselves, in order to profit from another product or market – but without describing every way in which that could be done.

Respondents in these types of cases have argued to the courts that FERC should be required to follow only strict rules-based enforcement rather than FERC's decision to follow precedent that more closely mirrors SEC law that holds that both rules and principles based enforcement are appropriate.

In that light, I thought the PJM report raised an intriguing point with regard to the possibility that if the courts narrowly hem in FERC's ability to monitor markets for manipulation, it could cause a future FERC to assess the costs and benefits of including financial traders within FERC jurisdictional markets, as the agency might not believe it would have the tools to adequately police the markets. PJM advocates avoiding such a scenario and thus encouraged participants and regulators to work towards a balanced solution. I think it's a good point and hope it will encourage us to continue this important dialogue.

This leads me to my second general discussion topic, which is the importance of proper price formation in FERC markets.

U.S. electricity markets are regulated by both state and federal regulators. FERC sets rates for wholesale and interstate service; states set rates at retail. More than a decade ago some states restructured their jurisdictional utilities to require divestiture of generation from transmission assets.

Effective and accurate pricing signals in FERC jurisdictional energy, capacity and ancillary service markets are critical in enabling the effective pursuit of FERC's mandate--just and reasonable rates.

It is within this context that the Commission in 2014 began a multi-year 'price formation' initiative to review, and when appropriate act, on the topics of: (1) uplift payments, (2) offer price mitigation and offer price caps, (3) scarcity and shortage pricing and; (4) operator actions, all of which directly affect the 'all-in' price of energy.

Price signals that reflect operating needs and system conditions enhance incentives for resources to respond to dispatch instructions. In the long-term, the Commission expects that appropriate price signals will produce prices that consistently reflect operating needs and system conditions which, in turn, will help to encourage efficient investments in facilities and equipment, enabling reliable service.

While Energy markets are the Commission's most mature markets, and probably its best functioning markets, from time to time we do need to engage in a check-up, or diagnostic testing to make sure that they're operating at the best efficiency for American consumers.

FERC's price formation initiative sets out an incremental process moving forward in this regard.

This approach to price formation allows the Commission to fully review, analyze and then address the large volume of information which the Commission has already collected. I have, and will continue to advocate for, a strategy which engages issues within the price formation initiative one bite at a time, acting only after the Commission is confident that it can assuredly correct a known deficiency, without creating second-order impacts which only create new challenges or inefficiencies.

In September, the Commission issued its first Notice of Proposed Rulemaking emanating from the price formation initiative. September's NOPR proposed revisions to Real-Time energy market settlement intervals, and revisions to how and when shortage pricing rules are placed into effect.

Regarding Real-Time settlement intervals, in the NOPR the Commission indicated that the misalignment between dispatch and settlement intervals may distort the price signals sent to resources and fail to reflect the actual value of resources responding to operating needs because compensation will be based on average output and average prices across an hour rather than output and prices during the periods of greatest need within a particular hour.

Requiring settlement intervals to match dispatch intervals could make resource compensation more transparent by, among other things, increasing the proportion of resource payment provided through payments of energy and operating reserves rather than uplift. Apportioning a greater proportion of a resource's revenue through payments for energy and operating reserves, rather than through uplift payments, increases transparency to the market by reflecting the costs of meeting system needs in settlement prices that are factored into a market price. In contrast, uplift payments bundle together a multitude of costs that are not factored into a market price. This increased transparency, in turn, better informs decisions to build or maintain resources and enhances consumers' ability to hedge.

Regarding shortage pricing, the Commission in the NOPR preliminarily found that a problem occurs if there is a delay between the time when a system experiences a shortage of energy and operating reserves and the time when prices reflect the shortage condition. This can be particularly problematic when, for example, a shortage is required to last a minimum time period before shortage pricing is triggered. In this instance, short-term prices may fail to reflect potential reliability costs, as well as the value of both internal and external market resources responding to a dispatch signal.

Implementing shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs would provide an incentive for resources to ensure that they are available to respond to high prices, which should help alleviate shortages and avoid shortage pricing during subsequent dispatch intervals. This reform would also ensure that resources operating during a shortage are compensated for the value of the service that they provide, regardless of whether the shortage is short-lived.

Again, as you read these concepts the Commission has put forward, I would encourage you to share your thoughts.

As for relevance to this audience: both proposed rules could have sizeable positive effects on your business operations. Any action which displaces pricing from uplift into the energy market and LMP, or better incentivizes price sensitive supply benefits financial products and the derivatives which settle off RTO/ISO LMPs. Establishing the 'right price' will mean hedges are more successful and speculative capital can be deployed more precisely.

These initial proposed rule changes should have positive effects on energy markets. However, the NOPR clearly indicates that the Commission expects to undertake further action addressing various price formation topics, including offer price caps, mitigation, uplift transparency, and uplift drivers in the near-term future.

It is also important to understand what this price formation effort is not, because I think this may sometimes be misunderstood.

The ongoing price formation initiative is not an attempt by the Commission to select winners and losers between specific generation or fuel types. The Commission has been resource neutral in its application of open market access and the development of market rules. Any attempt to move this dial would be a historic change for the Commission.

But getting the 'right price' is not the same as preserving *en masse* the existing generation fleet exactly as it looks today. In procuring a defined resource adequacy target, competitive wholesale electric power markets allow commodity price signals to dictate what resources will be successful, and what resources will be priced out by market competition.

Actions taken through the price formation initiative may not necessarily save resources whose cost profile is such that it is not economically viable in the face of downward pressure on wholesale energy prices, and to a lesser extent capacity prices. Take for example, what is happening with regard to merchant nuclear plants.

The past several years have seen multiple retirements across the US nuclear fleet, typically merchant plants in organized markets.

In addition to these concluded retirements, a wave of analyst and market speculation has surrounded the financial viability of multiple additional merchant nuclear units in the states of Illinois, Ohio, Pennsylvania, New Jersey and New York.

Conversely, all announced new nuclear builds are taking place outside of competitive wholesale electric power markets, in traditional, vertically integrated, bilateral market regions. These new builds include Watts Bar 2 (TVA), Vogtle 3 & 4 (Southern and partners), and Sumner 2 & 3 (SCANA and Santee Cooper).

This sequence of events has been highlighted by last week's announcement by Entergy that the Pilgrim Nuclear Power Station, a merchant nuclear facility located in the heart of ISO-NE would be retiring no later than June 2019. Pilgrim, a 685 MW single reactor, carbon-free resource, has more than 17-years left on its NRC operating license. Despite this potential lifetime, Entergy estimates that continued operations at Pilgrim would result in the loss of some $40 million dollars per year.

Looking at factors leading to these retirements requires a deep dive. Merchant nuclear power plants receive revenues for two services in competitive wholesale electric power markets - energy and capacity.

First, I'll discuss energy markets--

Cheap and abundant natural gas has been a game changer within the electric power industry. "Game Changer" is a somewhat overused term, but in the case of natural gas in the electricity generation business, I think the term is appropriate. As a proxy for this impact, one can review the incremental increase of natural gas-fired generation serving as the marginal unit in ISO/RTO's.

In PJM, natural gas-fired resources were the marginal resource in 26.5% of all real-time energy market settlement intervals in 2011. For the most recent year for which data is available (2014) this percentage is now 35.8%.

Marginal resource percentage figures for ISO-NE are even more striking. For 2014, in ISO-NE, natural gas was the marginal fuel during 70% of all real-time pricing intervals, followed distantly by coal and pumped-storage generation, which were marginal in only 8% and 7% of all pricing intervals.

Natural gas-fired marginal resource percentage figures indicate the profound effect on resource dispatch, utilization rates and energy market pricing. In all markets, specifically within the US Northeast, the trend on dispatch and utilization has been towards natural gas, while the trend in energy market pricing has been definitively down, with the exception of a few bumps such as the cold weather snap experienced in 2014.

While not comforting for merchant nuclear operators, this is the natural outcome of the unbundled regulatory model states themselves chose when they restructured, and I do not believe it can be characterized as a "market failure." Competitive resource migration – rather than state-selected resource planning are the very outcomes that were intended when competitive wholesale electric power markets were first designed. Older, higher cost resources exit the market, while newer, more efficient and lower cost resources enter.

Second, I will discuss capacity markets--

The Commission has acted in both ISO-NE and PJM to reform capacity markets where needed. In both markets the Commission has approved orders implementing fundamental changes to capacity market obligations such that holders of capacity awards carry a higher financial burden for non-performance. Capacity market reforms, like the price formation initiative are fuel and resource neutral. What they are not, however, is reliability neutral. Providing capacity obligation holders increased revenues for that service carries the explicit requirement that the resource be available when called upon.

The bottom line to me is: show me a region where states have severed the vertically integrated utility model and created a fleet of merchant generators, and have implemented renewable portfolio mandates, and where the marginal units dispatched are fired by low-cost natural gas, and I will show you a region where merchant nuclear will struggle. In such a circumstance, I don't know that FERC could design a market with any integrity that could send enough money towards certain merchant nuclear units if the unit in question is facing large investments to keep them running – as is often the case per nuclear licensing requirements.

As currently outlined by the Commission, the price formation initiative does not carry the intended mission of saving particular resources. Nuclear and other resource types with high fixed operating costs will continue to be challenged in a wholesale energy market driven by low natural gas commodity costs. While improvements have been undertaken in capacity markets to provide increased levels of supply guarantee, improvements that are open to nuclear resources, and may be beneficial to them because of their attributes, these changes have not been made to support one particular resource class. Rather, they are part of a wider, resource neutral approach to just and reasonable rates, ensuring reliability for American consumers.

I would argue that for those who are concerned about losing these or other units for their environmental benefits or their supply diversity, both worthy public policy goals, the appropriate starting point for discussion is with the states, which under the division of duties in the Federal Power Act retain resource adequacy, and resource planning authority in ways that FERC does not.

I would note, however, that should states go down that path, it will have an effect on FERC jurisdictional markets, which is something FERC will have to monitor so that our markets can operate as intended.

That brings me to my final topic, which is the challenge related to various state actions that may have an impact on FERC wholesale markets.

One potential threat to the health and viability of FERC jurisdictional competitive wholesale electric power markets is a trend that can be termed 'soft re-regulation.' This trend has been apparent within states that elected to restructure their jurisdictional utilities for some time, but under growing pressure from wholesale commodity price swings, federal environmental regulations and state level public policy decision making, these efforts have gained recent momentum.

States choose whether to keep the vertically integrated model or the unbundled model of utility structure. Having come from a vertically integrated state and having now worked with a number of restructured states in my time at FERC and as a President of NARUC, I would argue either model can work – they simply have different incentives and tradeoffs built in to the respective models.

Where my concern is targeted is those states that select to restructure, but then simultaneously seek to retain control over resource planning. To date, state level renewable portfolio standards along with other limited capacity portfolio interventions have managed to co-exist within competitive energy markets for those states that elected to restructure, albeit sometimes awkwardly. Going forward, a similar outcome is not guaranteed.

For example in Massachusetts, a restructured state within ISO-NE, legislation has been proposed which would require utilities to procure a volume of power that is the equivalent to approximately one-third of Massachusetts annual demand for electricity. Now I'm not specifically criticizing any particular legislation, but the effects of this proposed legislation would obviously be enormous to ISO-NE's energy and capacity markets.

But Massachusetts is not unique: similar state directed procurement plans are cropping up throughout restructured markets, in places such as Ohio, New York and Illinois.

The concern here is that the economic efficiency and benefits that competitive wholesale electric power markets have been designed to generate are challenged. On a policy level, a mix of traditional and restructured regulatory signals will inherently be more expensive for end users with no commensurate reliability benefits.

Put succinctly, you can choose to be Texas and restructure. You can choose to be Georgia and remain bundled. You can even choose to be California and remain bundled but operating within an organized market – although the way California has gone about it has resulted in high costs. But it is really tough to be Texas, Georgia and California all at the same time within one state, and I worry some states may be slowly drifting in that direction.

If that does happen, any action the Commission undertakes as part of its price formation initiative will be systematically undermined, and we will lose some of the value proposition of organized markets.

For my part, I would implore states, make your choice about how you want to structure your utilities, and once you do, stick with it. But if you are going to make a change do it - as one stakeholder recently told me - with a purpose, be purposeful. Do it in such a way that your choices mesh with your regulatory model, not work at cross-purposes with it. If you are, in fact, trying to put the restructuring toothpaste back in the proverbial tube, then do it in a transparent and open manner. Then, at the very least FERC can attempt to structure its wholesale market designs in a way that ensures just and reasonable rates, and so that investors and traders have some degree of regulatory certainty with regard to the markets they are entering.

Finally, I would also add, briefly, a somewhat separate, but very similar issue, which is the effect that Environmental Protection Agency's 111(d) carbon regulations may have on markets due to the way in which states are likely to implement it. The manner in which states are going about writing state implementation plans (SIP) will bear close scrutiny. Although EPA provided a path for compliance that would allow regional market based compliance, the politics of writing SIPs are such that I believe most states will end up utilizing more command and control tools in their plans, with perhaps a mix of some credit trading thrown in. The problem is that some of the ways of complying could erode the value proposition of organized markets. Time prevents me from delving into these issues this morning, but I suspect this will be a real issue over the next few years.

On this matter, Dr Hogan, who is speaking later during your program, has authored a working paper that I'd commend to your reading as it identifies some of these compliance risks.

With that, I will conclude my remarks, but would be happy to take any questions you might have as time permits.