UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	**Docket No. RM18-1-000**

NRG Energy, Inc. ("NRG") welcomes the opportunity to provide comments in response to the Notice of Proposed Rulemaking issued by the Department of Energy ("DOE") under Section 403 of the Department of Energy Organization Act. The Grid Reliability and Resilience Pricing Notice of Proposed Rulemaking (the "Grid Reliability NOPR")[1] identifies the urgent need for action by the Federal Energy Regulatory Commission (the "Commission") to reform its jurisdictional energy and capacity markets. NRG also provides answers to the questions asked by Mr. Arnold Quinn as an appendix to this filing.

I. Executive Summary

The Grid Resiliency NOPR rightly points out that competitive energy markets are facing fundamental challenges brought on by a combination of state subsidies to select generators, the Shale Gas Revolution, increased renewables penetration, and stagnant load growth. Without urgent reforms, the confluence of these factors threatens to swamp the ability of the competitive markets to attract capital into energy infrastructure, undermining reliability and ultimately increasing consumer costs. These trends have led to a severe disconnect between the actual costs to reliably operate the bulk power system and the price signals sent to generation owners. Despite ample evidence of the need for immediate Commission action to address these problems, reforms have been slow to arrive – far too slow, in NRG's view.

[1] 82 *Fed. Reg.* 46,940 (Oct. 10, 2017).

NRG fully agrees with DOE that market reforms are urgently needed. Many of the themes laid out in the Grid Reliability NOPR echo those heard at the May 1-2, 2017 Technical Conference on the Interaction of Markets and State Policies,[2] which established an extensive record supporting the need to act on dockets pending before the Commission and the need to modernize the price formation process in both the capacity and energy markets. Our nation has traditionally relied on the fuel security and 'resiliency' attributes of traditional baseload units without having to worry about whether market rules specifically priced those attributes and assured their adequate compensation. As the Grid Resiliency NOPR notes, today's low prices are leading to the retirement of facilities capable of withstanding "major fuel supply disruptions."[3]

While the DOE is right that wholesale markets are badly in need of reform, and that reform is needed immediately, the NOPR missteps in urging a retreat from markets towards cost-of-service regulation. The Commission cannot fulfill its statutory obligation to assure just and reasonable rates by fighting subsidies with more subsidies.[4] Cost-of-service subsidies from FERC would needlessly cost consumers billions, just as the nuclear bailout programs adopted by New York and Illinois already are scheduled to cost consumers in those states more than $10 billion over the next decade. For that price, the consumers in those states are buying themselves nothing in terms of reliability or rational markets; they are simply footing the bill for political compromises by their state officials.

The Commission should keep the sense of urgency conveyed by the Grid Resiliency NOPR, but reframe the question to ask "how should we adapt competitive markets to ensure that

[2] *See* Docket No. AD17-11-000.

[3] Grid Resiliency NOPR, at 46,941.

[4] As Dr. Bowring put it, "Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies." *Statement of Joseph Bowring, Independent Market Monitor for PJM*, filed May 1, 2017, in Docket No. AD17-11-000.

we maintain grid resiliency and drive investment in a least-cost fashion." The Commission should ignore the naysayers, whose dislike for the *remedy* set forth in the Grid Resiliency NOPR has tempered their enthusiasm for reforming markets. Ironically, many of the same entities urging caution or delay today were in full-throated agreement about the need for fundamental reforms at the May Technical Conference. In that spirit, the Commission should view the Grid Resiliency NOPR as an invitation to refine, not abandon, wholesale energy markets, and should put in place market structures that value resiliency attributes in a way that *strengthens* competition.

NRG recommends that any final rule adopted by the Commission (whether in this docket or in subsequent proceedings) follow these four pro-consumer principles:

1. Apply fuel-neutral pricing principles to incent competition and innovation across the entire energy sector;

2. Directly identify the attributes sought and allow all qualified market participants to compete to provide those attributes;

3. Focus on price formation solutions that improve the market's ability to accurately value reliability; and

4. Ensure that for-profit organizations that voluntarily entered the competitive market are not bailed out by captive customers.

Adhering to these competitive principles will ensure that consumers receive the best possible combination of service and affordability, and encourage investors to put shareholder money at risk rather than ratepayer funds. Our sector has too long been dominated by slow-moving incumbents who want to saddle captive customers with the cost of failed utility projects and bad investments, and who live off the core economic principal of rate base: the more money you spend, the more money you make. Competitive markets have demonstrated time and time again that consumers benefit when vibrant competitive markets promote the injection of *private shareholder capital* into the energy sector.

There are pro-competitive and pro-consumer solutions that will ensure grid reliability and resiliency through competitive markets. While this is not an exhaustive list of possible actions that would enhance reliability and resiliency, we recommend that the Commission:

1. Immediately act on existing dockets to eliminate distortions in the capacity and energy markets that are driving many existing resources out of the market;

2. Direct ISOs and RTOs to propose price reforms that would allow all units dispatched as part of the real-time reliability solution to set prices in their wholesale energy markets, or explain why such reforms are not necessary in their footprint; and

3. To the extent necessary to ensure fuel security, create a fuel-neutral "Forward Resiliency Market" to allow qualified resources to compete to provide resiliency services.

We discuss below how each of these recommendations would help ensure the reliability and resiliency of the grid, ensure generators receive just and reasonable rates for the services provided, and secure the financial viability of resources necessary to ensure the continued reliable and resilient operation of the bulk power system.

II. About NRG

NRG owns approximately 30,000 MW of generation across the country.[5] This includes approximately 15,000 MW in the FERC-jurisdictional wholesale markets, 10,000 MW in ERCOT, and 5,000 MW of renewable and conventional generation under long-term contracts, owned by NRG's affiliate, NRG Yield, Inc. NRG has the following conventional generation in the Commission-jurisdictional markets:

Market/Total Megawatts	Approximate Size/Type of Resources
PJM – 5,000 MW	3,200 MW of coal 1,400 MW of natural gas 450 MW of oil
MISO – 3,500 MW	2,600 MW of natural gas 900 MW of coal

[5] NRG's wholly-owned affiliate, GenOn Energy, Inc., recently declared bankruptcy and has implemented separate management as part of the restructuring process. Thus, we exclude the resources owned by GenOn.

NYISO – 2,800 MW	1,200 MW of natural gas 1,600 MW of oil
CAISO – 2,100 MW	2,100 MW of natural gas
ISO-NE – 1,500 MW	1,500 MW of oil and natural gas with oil backup

Thus, almost exactly half of NRG's fleet of conventional generation has some level of on-site fuel storage which would potentially benefit from separately pricing a resiliency product that provides additional revenues for maintaining fuel stockpiles. Despite the superficially attractive premise of rate-basing a substantial portion of our generation fleet, at enormous additional cost to ratepayers, NRG is inherently a pro-competition company, with zero captive customers, and believes that only competitive market structures that deliver value for end-use customers has any long-term hope of surviving.

III. Action in Existing Commission Dockets, with Ample Evidentiary Records, is a Critical First Step Towards Improving Wholesale Markets.

The Commission has collected record evidence of dysfunction in the wholesale market for a number of years now, but has done relatively little to enhance price formation or protect the market against subsidized new entry or uneconomic retention. In NRG's view, the Commission's first step should be to stop the bleeding that is threatening the viability of many generation resources by acting on several dockets currently languishing at the Commission. These dockets often have fully developed records and have the potential to greatly improve the ability of markets to adequately compensate resiliency resources and better reflect the true costs of maintaining a reliable electric grid – and to do so quickly. Thus, as a first step to meeting the goals of the Grid Resiliency NOPR, NRG recommends bringing the following dockets to a swift conclusion:

1. Capacity Market Reforms in New York and PJM would Immediately Make Resiliency Resources More Competitive.

The greatest policy threat to the economics of NRG's existing generation resources (including many coal- and oil-fired units with on-site fuel supplies) in PJM and New York are not environmental regulations or increasing competition from renewables. Instead, the greatest threat they face is the uneconomic price suppression caused by state programs designed to keep economically failing nuclear plants alive and participating in the market. The Commission has been sitting on complaints designed to end the devastating impact these and other uneconomic retention subsidies are having on the competitive markets for years. The New York case has been pending, in various forms, since 2013,[6] while the PJM case has been pending since early 2016.[7] *NRG's commercial analysis is that no other single action the Commission could take would improve the competitive markets more than acting on these long-delayed dockets*.

Corporate bailouts targeted to specific fuel types or companies, whether they are being implemented on a state-by-state basis or at the national level, are directly contrary to the uniform American experience that competition drives down prices, increases quality of service, and encourages technical innovation. Indeed, the answers to the questions posed by today's conversation – whether consumer welfare increases more through a vibrant competitive market or through prescriptive state mandates – would be so obvious in virtually all other sectors of the economy that the question itself would not even be asked. Fortunately, Congress, multiple presidential administrations, and this Commission under the Chairmanship of commissioners of both parties have all declared competitive markets to be in the national interest.

[6] *See* Docket Nos. EL13-62-000, -001 and -002 (highlighting that action was "vital" to protecting NYISO's capacity markets).

[7] *See* Docket No. EL16-49-000 (highlighting the "existential threat" to PJM's capacity markets).

The damage to the wholesale market caused by the New York and Illinois programs is enormous, both in terms of investor confidence and in revenues. Initial estimates are that the Illinois program will suppress energy and capacity market revenues by approximately $500 million annually in the ComEd Zone of PJM alone, hundreds of millions more across the entirety of the PJM footprint, and impose $235 million a year in needless costs on Illinois consumers for a decade.[8] The impact on generators in New York is of similar magnitude, and the nuclear bailouts are expected to cost consumers in New York $7.6 billion over twelve years. Ensuring that all resources receiving discriminatory subsidies that affect investment or retirement decisions are bidding at their actual, unsubsidized, going-forward costs would restore competitive balance to the markets and ensure that competition survives while the Commission works on longer-term price formation measures.

These bailouts are particularly egregious because consumers have paid for these plants at least three times. *First*, they paid the full cost-of-service to build the plants under ratebase. *Second*, consumers paid stranded costs to the owners when the states went through electric restructuring. *Third*, consumers more than paid for the plants once again during the 2000s, when natural gas prices were high. Now, consumers in New York and Illinois are being required to pay for these plants a fourth time – with all of the benefits accruing to a single corporate entity: Exelon.

Similarly, Ohio is currently considering bailing out long-past their prime, inefficient coal and nuclear facilities, and pro-consumer forces are still fighting back efforts to subsidize the Millstone nuclear generator in Connecticut as well.[9] For facilities located near the subsidized

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[8] *See* DeRamus Declaration to Plaintiffs' Motion for Preliminary Injunction at ¶ 6, Electric Power Supply Association, et al. v. Anthony M. Star, et al., 17-cv-1165, (N.D. Ill. filed March 31, 2017).

[9] One analysis showed that Dominion's Millstone nuclear plant, which is currently seeking a bailout from the citizens of Connecticut, was so profitable that "[w]ithin five years, the original purchase price was repaid" and the "subsequent run-up in natural gas and electricity prices through 2008 created additional

resources, the only answer is either to defer additional capital expenditures, shrink staff, or close the plant entirely.

When market prices were relatively high, the entities now seeking bailouts were happy to reap the associated profits. However, now that wholesale market prices are relatively low, these same entities are seeking ratepayer-funded bailouts of their timeworn and non-competitive generation. The result is that competitive generators, including gas, coal, and renewable generation, are competing against resources that are receiving substantial non-market payments, rendering them indifferent to market outcomes, and inefficiently bolstering their competitive position. Such behavior unquestionably distorts the wholesale markets overseen by this Commission and irreparably harms market participants relying on competitive market outcomes.

These out-of-market initiatives are happening now and are having a chilling effect on NRG's ability to deploy capital into these markets. The fact that additional states are considering similar interventions in the competitive markets only adds to the cloud of uncertainty. Lest there be any doubt, unless the Commission enacts strong policies preserving competitive markets, there is a real possibility that years of progress will be reversed and large swaths of the electricity sector will replace competition, backed by shareholder investment, with corporate welfare programs, backed by captive ratepayers.

Ironically, the price suppression associated with propping up these selected plants has exactly the same debilitating impact on the wholesale markets that the Grid Resiliency NOPR's proposal to re-rate-base a subset of the competitive market. Indeed, many of the plants most harmed by the price suppression are the *unsubsidized* coal and nuclear units that the DOE is

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profits for Millstone equity holders[.]" *See* Financial Assessment Millstone Nuclear Power Plant, by Energyzt, April, 2017 (*available at*: https://epsa.org/wp-content/uploads/2017/05/4250100000005.filename.ENERGYZT_Assessment_of_Millstone_201704_FINAL-1.pdf).

concerned are retiring prematurely. Notably, the Federal Power Act does not require the Commission to accommodate programs that are at odds with the Commission's competitive market framework.[10]

2. Preferential Treatment of Renewables in New England Likewise Harms the Competitive Market and Increases Costs to Consumers.

NRG notes that there is another capacity market case currently pending before the D.C. Circuit Court of Appeals that may warrant additional Commission action. This case involves whether the prior Commission acted appropriately when it exempted up to 200 MW annually of renewable resources from the application of ISO-New England's Minimum Offer Pricing Rule ("MOPR") rule. Importantly, all other new resources (whether conventional generation or demand-side) are required to undergo pricing review. The arbitrary exemption of renewable resources significantly harms price formation in New England and could take an estimated $361 million out of the market annually.[11] These dollars should be compensating new and existing capacity resources, but instead are being artificially removed from the market. The reconstituted Commission should explore requesting remand of this case and elimination of this economically unwarranted treatment of one technology class.

As the Commission itself has acknowledged in response to its initial voluntary remand from the D.C. Circuit Court of Appeals, the rationale advanced by the Commission in initially approving the exemption has been thoroughly discredited. However, instead of retreating from its market-destroying policies, the prior Commission doubled down on its prior order, and suggested that, because the amount of uneconomic renewable projects that have entered the

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[10] States may enact environmental protection measures, but any such law must yield "if it interferes with the methods" prescribed by federal law. *Int'l Paper Co. v. Ouellette*, 479 U.S. 481, 494 (1987).

[11] As a rough approximation of the impact of 200 MW of new generation coming into the market can be calculated as follows: 35,000 MW (approximate quantity procured in recent years) x 12 months x $0.86/kW-mo (based on 200 MW and the slope of the linear demand curve of 43 cents/100 MW).

market recently has been well below the 200 MW annual maximum, that the harm to the market was relatively small and did not warrant reversing its prior decision. We request that the Commission immediately again seek a voluntary remand of this case, and this time, require all resources to enter the market at their true costs.

3. Existing Price Formation Initiatives.

The Commission has likewise been sitting on several price formation initiatives for several years now. These pending initiatives would enact such commonsense reforms as allowing "fast start" peaking resources to set wholesale market prices for the duration of the time they are dispatched.[12] Fast start combustion turbines are typically more expensive than other generation resources, and are usually called upon only as a last resort, often when load is high or the system is in distress. Current market rules in PJM and California (as well as in the non-jurisdictional ERCOT market), for example, largely either ignore these expensive resources when setting prices or fail to value the attributes that such resources provide.[13] Similarly, the Commission initiated its "Operator Actions NOPR" in 2015, which, (true to its name) is designed to ensure that prices reflect supply/demand conditions even when operators take actions to ensure the reliability of the grid, such as turning on additional resources.[14] While system conditions may warrant a degree of operational conservatism, it is critical that the market continue to send price signals as if those out-of-market operator actions had not happened. Both

[12] *See* Docket No. RM17-3-000.

[13] California's real-time dispatch increasingly values these kinds of resources, which can start and shut down several times a day to avoid running over the high solar "belly of the duck" afternoon period. However, this value is not reflected in the bilateral capacity market underlying California's Resource Adequacy program, which currently assigns no incremental value for providing this kind of operating flexibility.

[14] *See* Docket No. AD14-14-000.

NOPRs have fully developed evidentiary records, and ample support from lawmakers of both parties.[15]

IV. To the Extent Pricing Resiliency is Deemed Necessary, the Commission Should Rely on Market-Based Solutions to Price Resiliency in the Wholesale Markets.

There are a variety of options that the Commission could take that would achieve many of the goals laid out in the Grid Resiliency NOPR in an economically principled manner. Any such measure should be fuel neutral, so as not to run afoul of the Federal Power Act's prohibition on undue discrimination, and specifically identify the products or attributes that the Commission deems critical to long-term security of the grid. Fuel neutrality is not only a legal imperative, but also ensures that consumers receive the resiliency attributes they purchase on a least-cost basis, consistent with competitive market principles. After all, the grid does not care whether it is receiving resiliency attributes from a battery storage system, natural gas generator backed up with dual-fuel, or a nuclear unit with uranium in the reactor.

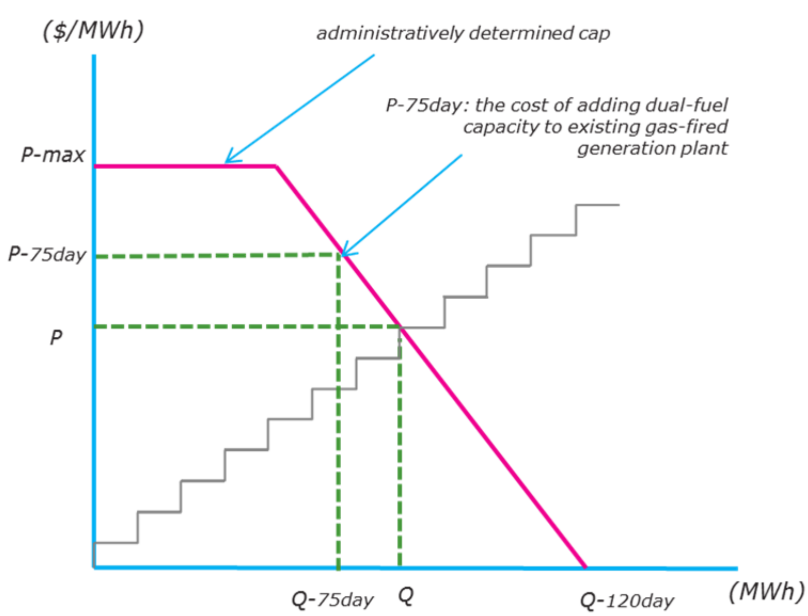
One option would be for the Commission to institute a "Forward Resiliency Market," or "FRM" in each of the relevant ISOs and RTOs. The FRM is a quarterly auction-based program designed to ensure that each organized market has sufficient on-site fuel to supply the megawatt-hours of production needed to allow the ISO/RTO to operate for the next 90 days. The FRM would specifically define the resiliency product as "a supply-side resource's ability to generate megawatt-hours of electricity using on-site feed stocks." This would ensure that the grid is resilient against catastrophic failures or disruptions of the natural gas supply or coal supply,

[15] *See*, *e.g.*, Letter from Senator Murkowski, Congressman Upton, and Congressman Whitfield to the Honorable Norman Bay, July 8, 2015 (*available at*: https://archives-energycommerce.house.gov/sites/republicans.energycommerce.house.gov/files/114/Letters/20150708FERC.pdf).

whether caused by weather events, terrorist incidents, loss of railway and/or road infrastructure, or other unforeseen events.

While there are a variety of ways to design such a system, one approach would be that each organized market would identify the total megawatt-hours of electricity that it expects its customers to consume over the upcoming quarter. Any qualified market participant would be allowed to bid in its total ability to supply a share of the market's total needs for the forthcoming quarter, with its maximum contribution limited to the amount that it could generate using on-site fuel supplies, while maintaining compliance with environmental regulations. Each market would signal the "value" of the resiliency product by establishing a downward sloping demand curve, with the zero crossing point representing 120 days of on-site fuel, and anything less than 75 days of fuel setting the value of resilience at the cost of adding dual-fuel capability to an existing gas-fired generation plant, as illustrated in the following schematic:

Illustration of Forward Resiliency Market



The FRM is pro-competitive because it would allow *all* resources with on-site fuel to compete to supply the market with resiliency service, regardless of the underlying technology. Thus, a natural gas-fired resource with dual-fuel capability would be able to reflect the number of megawatt-hours of on-site operations it is capable of before refueling. Likewise, a battery resource with four megawatt-hours of storage capability would be able to participate in the auction, as would coal or nuclear plants. The FRM concept thus ensures that consumers receive the maximum amount of fuel security, at the lowest possible price, by requiring resources to compete against each other to supply the service.

Finally, the FRM program laid out here is relatively easy to implement on an expedited basis, because it is a self-contained program that does not require major re-writes of other portions of the tariff. Further, the procurement is on a market-wide basis, and open to all resources physically located in the footprint of the relevant market. It would allow prices to fluctuate, and existing or new generators would be financially incented to innovate to provide increase their on-site fuel reserves at the lowest possible price, thereby addressing the concerns raised in the Grid Resiliency NOPR about the loss of facilities capable of withstanding "major fuel supply disruptions."[16]

V. Next Generation Energy Market Reforms are a Critical Piece of Ensuring Markets Work.

There is no question that many of the resources highlighted in the Grid Resiliency NOPR have retired because energy market margins have decreased significantly in the past several years. Energy margins have historically accounted for a large portion of merchant revenues, but many of the organized markets have done analysis showing that, if currently mandated levels of

[16] Grid Resiliency NOPR, at 46,941.

renewables are brought onto the system, energy margins could virtually disappear.[17] For this reason, NRG sees the urgent need to reform the energy market price setting process.[18]

In modernizing energy markets to address the concerns raised in the Grid Resiliency NOPR, the Commission should look to ensure that all resources needed to reliably operate the grid are part of the price formation process. Traditional energy market pricing theory says that the marginal price should be set at the cost necessary to bring the next additional increment of energy to market. Coal, nuclear, and oil units inherently provided on-site fuel reserves, and a well-operated coal or nuclear plant was generally able to meet its going-forward costs through a combination of energy and capacity revenues. These same plants are particularly susceptible to being excluded from the price formation process. Thus, historically, it made little practical difference whether or not they were allowed to set price; reality dictated instead that natural gas units would set the price, even during the overnight hours, when load is typically at its lowest.

ISOs/RTOs routinely dispatch these traditionally baseload resources at either min or max load levels as part of a reliable system, and these resources are ineligible, by rule, to contribute to price-setting. As a result, real costs of maintaining reliability are often left out of the visible prices in the market. In practice, ignoring these units understates the actual costs of operating the grid, since coal units or nuclear units that the system is relying on often have an average cost of production far in excess of the LMPs.

Fast forward a decade, however, and many of these solid fuel units needed for reliability are now on the margin, but still play no role in setting LMPs. Instead, the LMPs are increasingly being set by variable resources with no appreciable marginal cost, or natural gas fired resources feasting on low-cost fracked gas. Thus, the electric system today finds itself in the odd position

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[17] *See, e.g.*, NYISO, Integrate State Policy report, May 2017.

[18] While it is possible to rely on capacity markets alone, they remain particularly susceptible to state interference.

that relatively expensive units are being relied upon every day to reliably deliver electricity to consumers, but play no role in setting energy market prices. And these units, likewise, are challenged to adequately represent their costs in capacity markets.

Consistent with its stated preference to see energy market reforms that apply to all competitive resources, NRG urges the Commission to direct each ISO and RTO to immediately lay out a timetable to ensure that all resources, dispatched as part of the least-cost, reliable operation of the system, are allowed to set real-time energy prices. Such a scheme is inherently pro-competitive. It ensures that consumers see the actual cost of serving demand reliably, while maintaining the single-clearing price market structure that the industry depends upon to send price signals. Ensuring that units operating inflexibly are allowed to set price also encourages competition from non-traditional forms of energy, which may find it easier to compete if energy market prices accurately reflect the costs of serving load. Finally, incorporating these resources into the market price also helps the competitive retail market, since many inflexible generators today are receiving make-whole payments, which are difficult to hedge and can result in significant volatility in the price to serve retail load. While any design will have to factor in opportunity cost to ensure resources follow dispatch signals, a net reduction of uplift costs will be a boon to the competitive retail market.

The Eastern ISO/RTOs have the benefit of seeing the extent of a changed load shape due to renewables and the extent of zero and negative prices that are occurring in California and Texas. While those impacts are just beginning to be felt in the Eastern markets, we anticipate that we will see significantly increasing renewable penetration in this region as well, perhaps even comparable to the renewable penetration in ERCOT or California. These markets, too, will need to identify market designs to provide efficient and effective price signals in operational time-frames *and* an effective basis for investment in new resources as zero-marginal cost proliferate. Indeed, PJM is already taking the lead on the next-generation of price formation initiatives with the release of its recent Whitepapers on the topic and NRG urges the Commission to direct each ISO/RTO to propose a plan for implementing these reforms necessary for a long-term sustainable market structure by a date certain.

VI. NRG Recommends Working with States to Harmonize Wholesale Markets and State Policy Objectives.

In parallel with these immediate efforts to finalize proceedings already before the Commission, the Commission is also going to need to grapple meaningfully with the impact of state actions on the wholesale markets. While the price formation and MOPR reforms discussed above will smooth over the cracks in the cooperative federalism between states and the Commission, ultimately, the long-term stability of the competitive markets requires that the Commission incorporate state policy goals into the wholesale market, and ensure that the resulting outcomes are just and reasonable. The current status quo – where many ISOs/RTOs over the past several years have agreed to politically expedient exemptions from mitigation (such as in PJM and ISO New England), or have simply turned a blind eye to massive state intervention (such as New York ISO), or have openly given up on competitive markets to meet resource adequacy (MISO and CAISO) – is unacceptable if the competitive markets are to succeed. The Commission should insist that each ISO develop an economically principled approach to 'accommodate' state policy preferences, while still maintaining market signals sufficient to drive merchant entry and exit.

As NRG explained at length the testimony of Peter Fuller and Abraham Silverman at the May 1st and 2nd Technical Conference in Docket AD17-11, NRG advocates a "Triple A" approach to energy markets: *accommodate* reasonable state preferences by ensuring that out-of-market spending does not fatally undermine the markets; *achieve* state objective through competitive processes that appropriately price new and existing resources; and then *adapt* the markets to reflect the long-term trend towards a low-carbon grid.

States can, and should, dictate the emissions profile of the power that their citizens consume, within the constraints laid out by the Federal Power Act, and the Supremacy Clause and Interstate Commerce Clause of the U.S. Constitution. However, the Commission also has a clear statutory role in mandating that the resulting wholesale rates are just and reasonable – both for buyers and sellers. The best way for the Commission to meet this statutory commandment is to apply competitive principles and incorporate the environmental targets set by the States into the relevant ISO/RTO market. As we explained in the filed testimony in AD17-11:

> NRG sees competition for long-term renewables contracts centrally cleared through an ISO-run market as a promising option for achieving long-term decarbonization at the lowest possible cost to consumers. Even more promising are the coordinated forward auctions for renewable *and* conventional energy recently floated during New England's IMAPP process. Such initiatives co-optimize the procurement of renewable and conventional capacity, resulting in a total fuel mix that delivers the State's preferred environmental goals at the least possible cost, while also ensuring that reliability is maintained. States would achieve all of their environmental goals and consumers would save money in the process.

In the Federal Power Act, Congress gave the Commission exclusive jurisdiction over sales of electric energy for resale, as well as programs "affecting" or "in connection with" those sales. As the *EPSA* Court explained, the Commission's statutory commandment to ensure just and reasonable rates is not optional:

> If FERC sees a violation of [the just and reasonable] standard, it must take remedial action. . . . That means FERC has the authority—and, indeed, the duty—to ensure that rules or practices affecting wholesale rates are just and reasonable.

Where State programs conflict with the Commission's authority under the Federal Power Act, the Supreme Court has made clear that the State programs must give way "if it interferes with the methods" prescribed by federal law.[19] Likewise, in *Miss. Power & Light Co. v. Miss. ex rel. Moore*, 487 U.S. 354, 374 (1988), the Court likewise held that "States may not regulate in areas where FERC has properly exercised its jurisdiction to determine just and reasonable wholesale rates or to insure that agreements affecting wholesale rates are reasonable." While the Commission under the prior Administration appeared reluctant to grapple with the impact of State programs on wholesale markets, this reluctance has led to the artificial decrease in revenues that has threatened many otherwise competitive baseload resources over the past several years.

VII. Conclusion

Whether the Commission rejects the Grid Resiliency NOPR or simply utilizes this docket to move forward with pro-market reform, NRG urges the Commission to modernize the competitive markets as expediently as possible.

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Respectfully submitted,

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[19] *See Int'l Paper Co. v. Ouellette*, 479 U.S. 481, 494 (1987).

APPENDIX: ANSWERS TO STAFF QUESTIONS

Need for Reform:

1. **Question:** What is resilience, how is it measured, and how is it different from reliability? What levels of resilience and reliability are appropriate? How are reliability and resilience valued, or not valued, inside RTOs/ISOs? Do RTO/ISO energy and/or capacity markets properly value reliability and resilience? What resources can address reliability and resilience, and in what ways?

NRG proposes that the Commission consider defining the “resiliency” attribute as the amount of megawatt-hours of electricity a resource can generate using on-site fuel.

According to the Merriam-Webster on-line dictionary, ‘resilience’ is “an ability to recover from or adjust easily to misfortune or change.” By contrast, the word “reliable” has two definitions: “suitable or fit to be relied on; dependable,” and “giving the same result on successive trials.” These commonsense definitions appear applicable to the energy industry.

In terms of reliability, today’s grid infrastructure has largely succeeded in delivering a high degree of “reliability” – that is, the grid is dependable and gives the same high degree of up-time performance, under a variety of system conditions. The system is “reliable” in the sense that it successfully secures against disruptions under a variety of successive trials (i.e., contingencies).

One way to view resiliency, by contrast, is that it is a measure of how *quickly* the system could be restored, should an unexpected “Black Swan” event significantly interrupt the ability of power plants to refuel – whether because of a failure of the natural gas transportation system, the inability to deliver coal, or an interruption to oil deliveries.

There is no question that the electric sector has moved closer towards a “just in time” fuel delivery system than it did a decade ago. Today, the carrying costs of maintaining large oil or coal stores are just too high in a highly competitive market with thin margins. Thus, NRG (and most other major players) have shrunk coal piles and reduced oil in on site storage in an attempt to remain competitive. While these are positive developments for keeping costs low (and thus reducing overall costs to consumers), the grid is more susceptible to refueling disruptions, particularly as we move toward ever larger amounts of natural gas-fired generation on the system.

2. **Question:** The proposed rule references the events of the 2014 Polar Vortex, citing the event as an example of the need for the proposed reform. Do commenters agree? Were the changes both operationally and to the RTO/ISO markets in response to these events effective in addressing issues identified during the 2014 Polar Vortex?

The 2014 Polar Vortex was an unprecedented weather event which exposed a number of concerns with the operation of the grid, as well as the operation of individual resources. In NRG's experience, generator failures typically fell into two camps: those driven by operational failures and those driven by fuel procurement problems. In response to the former, plant operators have improved cold-weather planning and updated the way in which coal is handled during a cold snap to prevent frozen coal piles, along with better winterization of facilities. The latter group of problems included the inability to replenish on-site fuel reserves, such as the inability to deliver oil after extended run hours. The subset of outages caused by the inability to deliver fuel would have been partially alleviated had facilities maintained greater on-site fuel stocks (particularly oil).

In NRG's view, the concerns raised by the Grid Resiliency NOPR are more likely to result from a catastrophic outage of large portions the natural gas transportation system or rail delivery system, than by weather events such as the Polar Vortex, which are typically relatively short in duration. Notably, the natural gas transportation system, while stressed, was largely available throughout the Vortex and core services remained largely online. Instead, the grid saw high prices and constrained supplies, but not a fundamental failure of a particular fuel delivery channel.

3. **<u>Question:</u>** The proposed rule also references the impacts of other extreme weather events, specifically hurricanes Irma, Harvey, Maria, and superstorm Sandy. Do commenters agree with the proposed rule's characterization of these events? For extreme events like hurricanes, earthquakes, terrorist attacks, or geomagnetic disturbances, what impact would the proposed rule have on the time required for system restoration, particularly if there is associated severe damage to the transmission or distribution system?

Extreme events, particularly high-impact, low-likelihood disruptions to the natural gas transportation, or our nation's roads and railways, could result in the electric grid having to rely on on-site fuel supplies while the problem was remedied. For example, microgrids during Superstorm Sandy were largely able to provide reliable service, so long as they had fuel to operate.

NRG does agree that increasing the amount of on-site fuel storage would increase the ability of the system to continue operating in the event of an extreme disruption to the distribution of fuel and feedstocks. The question the Commission will need to address is whether it makes sense to design the bulk power system to "insure" against these types of Black Swan events. Generating plants have traditionally been designed and built to withstand extreme weather, including high winds and floods. In light of recent trends indicating that weather events may be becoming more extreme and intense, all plants should review their preparedness and degree of storm hardening, and upgrade where appropriate. Historically, the vast majority of disruptions preventing the delivery of energy to customers have arisen from damage to the transmission and distribution system, which would not be affected by the Grid Resiliency NOPR.

4. **<u>Question:</u>** The proposed rule references the retirement of coal and nuclear resources and a concern from Congress about the potential further loss of valuable generation

resources as a basis for action. What impact has the retirement of these resources had on reliability and resilience in RTOs/ISOs to date? What impact on reliability and resilience in RTOs/ISOs can be anticipated under current market constructs?

Because resiliency is a relatively new concept, the market does not have enough information about changes to resiliency. Defining the relative attributes that constitute "resiliency" is clearly a necessary first step.

Regarding reliability, one empirical example is in New England. As recently as 2000, 30 percent of New England's generating capacity was made up of coal and nuclear (12% and 18%, respectively), and these two fuel types provided 49% of the region's energy.[20] As of 2016, through retirements, coal and nuclear made up only 11% of the region's capacity (2% coal, 9% nuclear), and provided 33% of the region's energy (2% coal, 31% nuclear). One additional nuclear unit, Pilgrim, is slated to retire in 2019, and the remaining coal capacity in the region is either scheduled for retirement or is subject to a divestiture process. To date, ISO-NE has found no reliability basis to object to any of these plant retirements, and continues to operate the system reliably on a day-to-day and going-forward basis.

Independent analysis of one of the remaining nuclear facilities in New England, the Millstone facility in Connecticut, has shown that the facility has been profitable and is expected to continue to be so, based on publicly-available data.[21]

5. **Question:** Is fuel diversity within a region or market itself important for resilience? If so, has the changing resource mix had a measurable impact on fuel diversity, or on resilience and reliability?

ISOs/RTOs should look at the exposure of their regions to interruptions that could occur due to a single-point failure, such as an upstream natural gas pipeline failure or a NRC safety mandate that would affect multiple nuclear units. ISOs/RTOs should evaluate whether there are additional scenarios or system contingencies that should be included in their planning for future resource adequacy and reliability, and in their daily operations to ensure a robust and secure supply of energy on a continuous basis.

To the extent necessary, ISOs may also seek to increase procurement of reserves to satisfy these contingencies.

General Eligibility Questions

1. **Question:** In determining eligibility for compensation under the proposed rule, should there be a demonstration of a specific need for particular services? What should be the

[20] https://www.iso-ne.com/about/key-stats/resource-mix

[21] https://epsa.org/wp-content/uploads/2017/05/4250100000005.filename.ENERGYZT_Assessment_of_Millstone_201704_FINAL.pdf

appropriate triggering and termination provisions for compensation under the proposed rule?

To the extent that the Commission moves forward with a resiliency product, it should first define the appropriate attribute(s) that contribute to resiliency. After defining the attribute, any resource, with any fuel stock, should be eligible to participate in supplying the attribute(s).

2. **Question:** As the proposed rule focuses on preventing premature retirements, should a final rule be limited to existing units or should new resources also be eligible for cost-recovery? Should it also include repowering of previously retired units? Alternatively, should there be a minimum number of MW or a maximum number of MW for resources receiving cost-of service payments for resilience services? If so, how should RTOs/ISOs determine this MW amount? Should this also include locational and seasonal requirements for eligible resources?

NRG urges the Commission to avoid utilizing a cost-of-service regime and instead define attributes that would increase system resiliency. All resources able to provide the specified attributes should be eligible to participate. For example, in NRG's experience, oil units played a critical role in keeping the lights on during the Polar Vortex and make valuable contributions to grid resiliency. This is particularly true in New England, where oil-backup makes up a large portion of the non-natural gas-fired capacity. There is no principled basis for excluding oil units from participating in this program.

Likewise, we see no reason to adopt minimum size requirements or restrict new or existing resources from participating.

To the extent these additional attributes are identified, a potentially fruitful template for procuring and valuing them in competitive markets is the Locational Forward Reserve Market in ISO-NE. This market establishes seasonal requirements for operating reserve capability, differentiated by speed of response and by location, and administers a seasonal auction to procure commitments to deliver reserves in real-time. While the specifics of other attributes will differ from operating reserves, the needs may or may not have locational aspects, and different subsets of the generation fleet may have the technical capabilities to be eligible to provide the identified attribute, the general approach of a separate attribute procured on a forward basis as a 'premium' characteristic beyond basic capacity and energy could be a useful model for future market designs.

3. **Question:** If technically capable of sustaining output for a sufficient duration (and meeting other relevant requirements), should resources such as hydroelectric, geothermal, dual-fuel with adequate on-site storage, generating units with firm natural gas contracts, or energy storage (each of which might have a demonstrable store of energy to draw upon to sustain an electrical output, if not necessarily fuel) also be eligible? Why or why not? If technical capability is the appropriate criterion for eligibility, what specific technical capability should be required to be eligible?

All resources capable of supplying the desired attribute should be eligible to participate.

4. **Question:** The proposed rule would require that eligible resources be able to provide essential energy and ancillary reliability services and includes a non-exhaustive list of services. What specific services should a resource be required to provide in order to be eligible?

The Commission should clarify the requirement that qualifying facilities participate in the ancillary services markets. There are a number of ancillary services, including regulation, reactive power, black start service, spinning reserve, non-spinning reserve, etc. Coal and nuclear facilities are generally not well-suited to participate in many of these markets, as they do not typically provide fast-responding increases or decreases in output. Unless the Commission clarifies the requirement, resources may be forced to participate in markets for which they are not well suited.

Other potential products, some of which have been incorporated into current markets, should be explored.

- Ramping and flexibility – to ensure that ISO/RTO system operations can remain secure and reliable in the presence of large and rapid swings in net load, whether due to underlying load ramps such as occur in the morning and evening, or in response to changes in solar or wind output, ramping and flexibility products should be explored in each of the ISO/RTO markets.

- 'Performance' at times of system stress – Consistent with the performance requirements placed on capacity resources in the PJM Capacity Performance structure and the ISO-NE Pay for Performance structure, all markets should have long-run markets for resource adequacy, with obligations on participating resources to deliver energy and/or reserves in real-time during periods of reserve scarcity, with strong incentives to ensure successful performance in such periods.

- On-site fuel – to the extent on-site fuel is found to be a meaningful contributor to system reliability or resilience, a market construct based on treating the on-site fuel capability as a 'premium' product distinct from and in addition to standard capacity obligations and capabilities should be explored. For example, assume an ISO/RTO determined that having the equivalent of 100GWh of on-site fuel that could be held in reserve to be used in the event of fuel delivery or other system disturbances. The ISO/RTO could implement an auction or similar market mechanism to procure commitments from existing resources to hold on-site fuel that, in aggregate, fulfilled the 100GWh of 'fuel reserve.' The ISO-NE Winter Program of recent years provides a potential template for such a program.

5. **Question:** The proposed rule would limit eligibility to resources that are not subject to cost of service rate regulation by any state of local regulatory authority. How should

the Commission and/or RTOs/ISOs determine which resources satisfy this eligibility requirement?

NRG suggests that each generation owner seeking cost-of-service regulation attest that they receive no non-competitive revenues, including monies collected through non-bypassable surcharges, state subsidies, or other revenues not typical from the competitive market.

90-day Requirement

1. **Question:** The proposed rule defines eligible resources as having a 90-day fuel supply. How should the quantity of a given resource's 90 days of fuel be determined? For example, should each resource be required to have sufficient fuel for 24 hours/day and sustained output at its upper operating limit for the entire 90-day period? Would there be any need for regional differences in this requirement?

First, the Commission should clarify how the amounts of on-site coal should be measured. NRG recommends that the Commission utilize *forecasted* burns over the period of time set by the Commission. Using forecasted burns would ensure that plants keep an optimal amount of supply on site, and avoid having to stockpile coal that is unlikely to ever be burned. The other obvious methods of measuring fuel consumption – either based on the plant's minimum load level or the plant's economic maximum level – would likely result in inefficiently large piles of coal. Measuring the 90 day (or other length) requirement based on forecasted burns, by contrast, would ensure that coal stockpiles are commensurate with market demand.

Second, NRG recommends that the Commission modify the NOPR to look at shorter periods of time than the 90 days recommended by the Grid Resiliency NOPR. A 90 day period is substantially longer than most historic natural disasters, and would likely disqualify many coal plants from participating in the program, without major retrofits or expansions. While increasing the size of coal piles may tick some political boxes, it would also trigger permitting requirements, slow down the process considerably, and likely disqualify a number of coal plants from consideration because of space or other environmental issues.[22]

2. **<u>Question:</u>** Is there a direct correlation between the quantity of on-site fuel and a given level of resilience or reliability? Please provide any pertinent analyses or studies. If there is such a correlation, is 90 days of on-site fuel necessary and sufficient to address outages and adverse events? Or is some other duration more appropriate?

There is clearly a benefit to having on-site fuel reserves sufficient to "ride through" a failure of the natural gas transportation system or other fuel delivery channels. However, the value of this insurance product remains unclear. If the Commission determines that such a product is worth procuring, as discussed in the body of the comments, NRG suggests that the Commission consider securing sufficient on-site fuel reserves to serve the number of megawatt-hours each region needs for a specified period of time.

[22] Of course, depending on how the inventory requirement is calculated, the length of time becomes more or less of a gating item.

Fuel Supply Requirement

1. **Question:** The proposed rule requires that resources must be in compliance with all applicable environmental regulations. How should environmental regulations be considered when determining eligibility? For example, if a unit that was capable of keeping 90-days of fuel on-site was subject to emission limits that would prevent it from running at its upper operating limit for 90 days, should that unit be eligible under this proposed rule?

NRG proposes that each plant identify how many megawatt-hours of energy it would be able to produce over the next 90 days (or other period to be specified), while operating in compliance with all rules and requirements.

2. **Question:** As the proposed rule references the need for resilience due to extreme weather events, including hurricanes, should there be any other eligibility criteria for the resource or fuel supply (e.g., storm hardening)? What considerations should be given to the vulnerability of 90-day fuel supplies to natural or man-made disasters such as extreme cold temperatures, icing, flooding conditions, etc. that may impact the on-site fuel supply?

NRG submits that existing pay-for-performance markets already incent power plant operators to engage in storm hardening. In fact, many plants improved their procedures for dealing with extreme weather after the Polar Vortex. NRG suggests that the Commission focus its resiliency considerations on disruptions to the fuel transportation infrastructure, which is outside the control of any particular generation owner.

3. **Question:** Does the vulnerability or non-availability of on-site fuel supplies vary depending upon fuel type, location, region, or other factors?

Yes. Regions are more or less dependent on natural gas deliveries than other regions. For example, California has very little solid or liquid fuel resources on the system and would thus be more susceptible to disruptions of the natural gas transportation system. In such regions, the "marginal" source of environmentally-permitted on-site fuel is likely to involve new technology and innovation.

Implementation

1. **Question:** How would eligible resources receiving cost of service compensation under the proposed rule be committed and dispatched in the energy market?

Resources receiving cost of service compensation under the proposed rule should participate in energy markets on the basis of their actual (i.e., unsubsidized) fuel and other variable costs. Any market revenues received in excess of cost should be netted from the plant's cost of service for purposes of establishing cost recovery under the regulated rate.

2. **Question:** How would eligible resources receiving cost based compensation under the proposed rule be considered in the clearing and pricing of centralized capacity markets?

In energy markets, resources should participate at their actual fuel and variable costs, and should be eligible to participate in price-setting according to the tariff. In capacity markets, resources receiving cost-of-service compensation should be subject to the Minimum Offer Price Rule or comparable mitigation to ensure that the actual long-run plant economics are reflected in capacity market prices.

3. **Question:** What is the expected impact of this proposed rule on entry of new generation, reserve margins, retirement of existing resources, and on resource mix over time?

The proposed rule could have significant negative consequences. Providing cost-of-service regulated rates for these selected technology or fuel types within the ISO/RTO markets would add to existing over-supplied reserve margins, or contribute to maintaining the existing significant over-supply in all of the ISO/RTO markets. The inflated reserve margins and corresponding low prices, along with the policy preference for less flexible centralized power generating plants, would likely lead to increased retirements of newer, more efficient and more flexible resources, and a retrenchment on innovation and private risk capital in the electric power sector. All of these impacts would be negative for the long-run performance, cost and sustainability of the sector.

4. **Question:** Should there be performance requirements for resources receiving compensation under the proposed rule? If so, what should the performance requirement be, and how should it be measured, or tested? What should be the consequence of not meeting the performance requirement?

Absolutely. In addition to periodic testing to ensure the ability of each resource receiving cost-of-service compensation to operate consistent with its stated fuel type and operating parameters, the final rule should have a performance metric and settlement mechanism modeled on the PJM CP and ISO-NE Pay-for-Performance structures. Specifically, resources receiving the rule's compensation should be subject to penalty for failing to deliver their full output of energy and/or reserves at times of reserve scarcity. However, there should be no corresponding payment for 'over-performance,' since the cost-of-service compensation is, in effect, the 'upside' for these resources.

5. **Question:** Should there be any restrictions on alternating between market-based and cost-based compensation?

Yes. The Commission has recognized that once a resource voluntarily elects to enter the competitive market, it should remain a competitive resource, and that generators that "toggle" between market and full cost-of-service are "virtually guaranteed to earn revenues above costs over time."[23] Hence, Commission policy strongly disfavors allowing competitive resources to dip back into a cost-of-service regime.

In the context of this docket, the Commission should bar any unit receiving full cost of service from returning to market-based rates. Otherwise, subsidized generation owners would receive cost-of-service during periods of low revenues and higher than cost-of-service during periods of high revenues.

6. **Question:** Please describe any alternative approaches that could be taken to accomplish the stated goals of the proposed rule.

As described above, the Commission should use the impetus created by the Department of Energy's proposal to move swiftly to address a number of market design issues related to price formation and the ability of markets to support the transformation of the grid for the 21st century. Specifically, the Commission should:

- Direct PJM and ISO-NE to implement a two-tier pricing mechanism and expanded MOPRs in their capacity markets to address the entry or retention of otherwise uneconomic capacity, as discussed in the May 1-2 Technical Conference and in multiple stakeholder forums since. Direct each ISO/RTO without a forward capacity market to provide a report evaluating the applicability of such a structure to their market area, in particular as a platform for planning and supporting investment, and for accommodating subsidized resources.

- Direct each ISO/RTO to implement changes to their LMP algorithms to ensure that LMPs reflect the highest-cost resource dispatched in each interval to meet energy and reserve demands.

- Direct each ISO/RTO to evaluate changes to their LMP algorithms or settlement mechanisms to eliminate the effect of negative energy offers on non-renewable resources.

- Direct each ISO/RTO to implement one or more ramping or flexibility products in their markets, to ensure that flexible resources are properly

[23] *See, e.g., ISO New England Inc., New England Power Pool*, 125 FERC ¶ 61,102 (2008) ("We agree with ISO-NE that it is not reasonable to allow a resource that will remain in the capacity market in future years to toggle between cost-based and market-based compensation since a resource that could receive market prices when they exceed its costs and cost-based prices in the other years would be virtually guaranteed to earn revenues above costs over time. Providing a resource with a cost-based backstop would also blunt incentives for the resource to minimize its costs"). *See also New York Independent System Operator, Inc.*, 155 FERC ¶ 61,076 (2016) ("With regard to toggling, the Commission required NYISO to propose rules to "eliminate, or at least minimize, incentives for a generator needed for reliability to toggle between receiving RMR compensation and market-based compensation for the same units").

valued for their ability to respond to changes in system demand and supply variations.

- Direct each ISO/RTO to evaluate the need for on-site fuel storage as a protection against fuel delivery interruptions or other contingency situations, and if there is such a need, submit a proposal to define and quantify the need, and for a market-based mechanism to procure and value the service.

7. **Question:** What impact would the proposed rule have on consumers?

Competitive markets have been shown to provide substantial cost savings to consumers through placing risk and performance on investors and plant operators. Intrusions into those markets with directives for full cost recovery of certain generating technologies, especially where those technologies are being demonstrated to be less economic than other choices in the market, will inevitably cost consumers more money. In addition, the long-run impact of intrusions into the markets is hard to estimate, but is virtually certain to be negative for consumers. Competitive wholesale markets work, to the extent they do, because private investors and innovators believe that they will have an opportunity to earn competitive returns if they make good investments and operate efficiently. If regulations change such that increasing amounts of the 'market' are able to secure cost-of-service cost recovery and not be subject to the risk of market revenues, the incentive and opportunity for private investors to compete will shrink, and capital and innovation will seek other, more attractive options.

Certificate Of Service

I hereby certify that I have served a copy of the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Princeton, New Jersey this 23rd day of October, 2017.

/s/ *Abraham Silverman*

Abraham Silverman