UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	**)**	**Docket No. RM18-1-000**
NOPR of the Office of the Secretary of Energy	**)**	

MOTION TO INTERVENE AND COMMENTS OF THE FOUNDATION FOR RESILIENT SOCIETIES

Submitted to FERC on October 23, 2017; errata corrected October 24, 2017.

The Foundation for Resilient Societies, Inc. (or "Resilient Societies") is a 501(c)(3) non-profit organization engaged in scientific research and education to protect technologically-advanced societies from infrequently occurring natural and man-made disasters. Since our formation in March 2012 we have participated in the development of reliability standards under the auspices of the North American Electric Reliability Corporation (hereafter "NERC"), have petitioned the U.S. Nuclear Regulatory Commission (NRC) to adopt a rule for long-term unattended cooling power for spent fuel pools, and have proposed new and modified reliability standards before the Federal Energy Regulatory Commission (hereafter "FERC").

Per the fast-track Notice of Proposed Rulemaking (hereafter "NOPR") issued by the Commission pursuant to the Department of Energy proposed rule, Resilient Societies appreciates the opportunity to comment on "Grid Reliability and Resilience Pricing" in FERC Docket No. RM18-1-000.

Motion to Intervene

Pursuant to the Commission's Rules of Practice and Procedure found at 18 CFR Part 385, and specifically Rule 214(a)(3),[1] the Foundation for Resilient Societies, Inc. timely files this Motion to Intervene to become a party in the Rulemaking proceedings of Docket RM18-1-000. Resilient Societies takes a position in support of the goals of the Secretary of Energy for more

[1] 18 CFR § 385.214

resilient generating capacity in the Organized Markets, but through utilization of capacity market auctions that do not discriminate among electric generation technologies. The movant has interest in this proceeding because of its headquarters within the footprint of ISO-New England and its individual board members who are electricity consumers in various states served by the Organized Markets. The movant has performed relevant research and tracked changes in the availability of dual-fuel or backup fuel available proximate to sites of wholesale electric generation in both the Organized Markets and in the Traditionally Regulated Markets of the bulk power system.[2] [3]

It is in the public interest to allow the intervention of Resilient Societies as a party in these proceedings; and no other organization can adequately represent the interests of Resilient Societies.

Communications

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[2] See in particular the testimony of the chairman and president of the Foundation for Resilient Societies, Thomas S. Popik, at an invited Reliability Technical Conference sponsored by FERC under Docket No. AD17-8-000 and held at FERC Headquarters on June 22, 2017. The testimony compares and contrasts the relatively modest declines in dual-fuel capacity of the traditionally regulated markets, and the relatively rapid declines in dual-fuel capacity of the organized markets between FERC Order No. 888 in year 1996 and the last year with data across all markets available from the Energy Information Administration, year 2015. See "Testimony of the Foundation for Resilient Societies", June 22, 2017.

[3] For the purposes of this comment, we consider the "Organized Markets" to be states predominantly served by Regional Transmission Organizations (RTO) and Independent System Operators (ISO), also including ERCOT, and "Traditionally Regulated States" to be the remainder of the U.S.

Background on Foundation for Resilient Societies

The Foundation for Resilient Societies is dedicated to cost-effective protection of technologically-advanced societies and their critical infrastructures from infrequently occurring natural and man-made disasters. With recognized policy and technical expertise in the use of federal, state, and provincial regulation to protect electric grids from nuclear electromagnetic pulse, cyberattack, solar storms, and physical attack, our group is regularly asked to appear before official government bodies and industry forums. We have testified before the FERC, the Senate National Security and Defence Committee of the Canadian Parliament, and the U.S. House Committee on Oversight and Government Reform. We have deep expertise in the risks of long-term blackout and potential regulatory solutions, having made over two dozen filings in the reliability dockets at FERC and the NRC. Media sources such as the *Wall Street Journal, The Economist, Politico, USA Today, Reuters*, NBC, and Fox News rely on our knowledge of critical infrastructure threats and cost-effective protections.

Interest in Proceeding

Resilient Societies is headquartered in Nashua, New Hampshire within the footprint of ISO-New England. This ISO is arguably more vulnerable to long-term blackouts than any other region of the United States and therefore Resilient Societies has a special interest in this FERC proceeding to improve resilience of generation resources in New England and Organized Markets elsewhere.

New England imports significant power from adjoining systems. In 2016, 17% of electric power served was imported. On most intersystem ties, imports greatly exceed exports. A consistently high source of imports is the Hydro-Quebec Phase II line, a High Voltage Direct Current (HVDC) link with a history of tripping off during moderate solar storms.[4] Physical attack is also a threat

[4] Solar storms caused the Phase II HVDC link to trip off on March 24, 1991 and again on October 28. The second storm caused "material damages" to equipment, in addition to the trip. See Leonard Bolduc, "GIC observations and studies in the Hydro-Quebec power system," *Journal of Atmospheric and Solar-Terrestrial Physics* 64 (2002) p. 1793. Available at: http://www.sciencedirect.com/science/article/pii/S1364682602001281

for long-distance transmission lines. On December 4, 2014, imports from Canada were interrupted by an airborne terrorist attack on the Hydro-Quebec transmission lines near James Bay, Quebec.[5] The unreliable nature of New England's power imports makes on-site fuel storage at generators particularly important.

In 2015, natural gas-fired plants represented 49% of electricity generation and 42% of net energy for load in New England. Natural gas generators use fuel supplies that are not contractually firm and vulnerable to physical disruptions. Gas transmission pipelines are capacity constrained; the New England electric grid is not resilient to N-1 contingencies from gas interruption.

Because the electricity markets in New England do not account for the externality of long-term blackout and also because of outside-the-market incentives for renewable energy, current and future generation adequacy is at risk. Major generator retirements include Salem Harbor Station (coal and oil) at 749 MW, Vermont Yankee (nuclear) at 604 MW, Norwalk Harbor Station (oil) at 342 MW, Brayton Point Station (coal and oil) at 1,535 MW, Mount Tom Station (coal) at 143 MW, and Pilgrim Station (nuclear) at 677 MW. The total of these retirements is 4,050 MW, or approximately 12% of cleared capacity for New England. According to ISO New England, another 7,956 MW of retirements are looming; nearly all are oil-fired or older natural-gas fired plants.[6]

Use of the spot markets for supply to natural gas-fired plants works well on most days but not when retail gas customers are heating their homes during very cold winters. On January 7, 2014, New England capacity margin declined to a razor-thin 44 MW. In its "January 2014 FERC Data Request" report, ISO New England stated that "A total of six natural-gas fired generators on the New England system reported to ISO-NE that they were unable to affirm whether they

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[5] Behr, Peter. "Outage on Quebec power grid traced to airborne attacker." *Energywire*. June 17, 2015. https://www.eenews.net/stories/1060020352

[6] Johnson, Eric and Connors, Molly. "ISO New England Overview and Regional Update." Report. ISO New England. January 27, 2017. p. 17. https://www.iso-ne.com/static-assets/documents/2017/01/final_iso_new_england_overview_vermont_legislature_january_27_2017.pdf

would be able to procure fuel when called intraday during the period from January 7 – 8, 2014." The report to FERC reveals that during this same period, cumulative capacity reduction from fuel shortages was 1,280 MW.[7] Also on January 7th, the concurrent failure of a large gas compressor on the Texas Eastern system at Delmont, Pennsylvania reduced gas nominations by 575,000 million BTU in southern New England, causing the lateral pipeline on the Algonquin system that feeds Rhode Island and southeastern Massachusetts to be physically sealed. Six electric generators fueled by natural gas advised ISO New England that they could not affirm their ability to procure fuel when called intraday.[8] Mispricing encouraged early consumption of stockpiled fuel oil, so many dual-fuel reserve storage tanks were empty as firm customers used most of the natural gas for building heating. A regional blackout was barely averted.

More generally, the Organized Markets have incentives to utilize higher shares of capacity, eliminate dual-fuel supplies that are not compensated adequately, and contract for energy delivery over longer distances and multiple institutional boundaries. [9] When energy is delivered over long distances, vulnerability to cyberattack and physical attack is exacerbated.

Approximately 3,000 MW of new natural gas capacity has come forward in ISO-New England's recent capacity auctions.[10] However, all of this additional capacity would depend on a natural gas system that is close to its operating limit and susceptible to N-1 and also N-2 contingencies.

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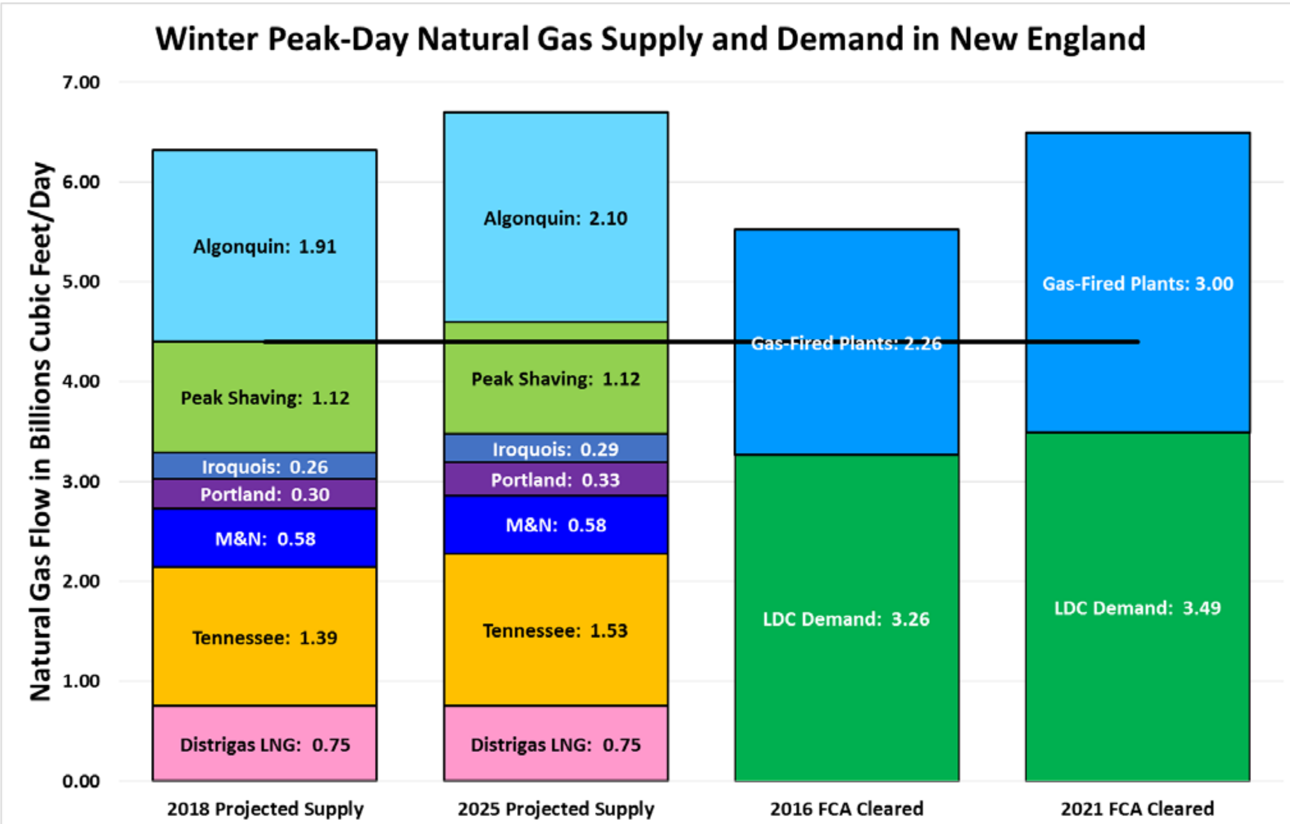
[7] ISO New England. "January 2014 FERC Data Request." Report. ISO New England System Operations. January 10, 2014. p. 2, p. 10. https://www.iso-ne.com/static-assets/documents/pubs/spcl_rpts/2014/iso_ne_response_ferc_data_request_january_2014.pdf see also ISO New England's Internal Market Monitor: 2014 Annual Markets Report, May 20, 2015, https://www.iso-ne.com/static-assets/documents/2015/05/2014-amr.pdf

[8] ISO New England Internal Market Monitor 2014 Annual Report, *ibid*, at p. 24, at fn 46. In the prior year, between January 21 thru January 28, and in February 2013, New England also experienced severe shortages of interstate natural gas availability.

[9] See Paul Hines, Jay Apt, and Sarosh Talukdar, "Large Blackouts in North America: Historical trends and policy implications," Carnegie Mellon Electricity Center Working Paper CEIC 09-01; Ian Dobson, "Estimating the Propagation and extent of Cascading Line Outages from Utility Data with a Branching Process," *IEEE Trans. Power Systems* (2012) 27: 2146-2155; B. A. Carreras, D. E. Newman, and I. Dobson, " "North American Blackout Time Series Statistics and Implications for Blackout Risk," *IEEE Trans. Power Systems* (2016) 31: 4406-4414;

[10] Johnson, Eric and Nuara, Weezie. "ISO New England Regional Electricity Outlook." Presentation to Connecticut General Assembly Energy and Technology Committee. ISO New England. January 24, 2017. p. 7. https://www.iso-ne.com/static-assets/documents/2017/01/iso_new_england_connecticut_energy_and_technology_committee_presentation_january_24_2017.pdf

Due to the inadequate design of the New England energy and capacity markets, 10,000 MW of gas-fired generation can be dependent on a single pipeline, the Algonquin, and still this is not considered an N-1 contingency.



Source: ISO-New England, Resilient Societies analysis

As illustrated by the black horizontal line on the above graph, we estimate that interruption of the Algonquin pipeline in 2018 would result in loss of about half of the fuel supply for gas-fired plants; interruption of this pipeline in 2025 might result in loss of about two-thirds of the fuel supply for gas-fired plants.

Despite narrowly missed load sheds, penalty caps in the Forward Capacity Market (FCA) for failure to provide capacity during "shortage events" are modest—only 2.5 times the monthly capacity payment.[11] Capacity market penalties for generators are a tiny fraction of the societal costs were a blackout to result from insufficient capacity, which can be estimated to the first order by lost GDP during and after the blackout—approximately $3 billion per day for New England in total.

ISO-New England has promoted use of wind and solar generation. However, because wind generation is non-dispatchable, and because solar generation does not contribute to evening peak capacity in New England, natural gas generation will be required until storage technologies dramatically improve. Inadequate regulation and incentives for construction of additional gas pipeline capacity limits new gas-fired generation and places existing generation at risk of fuel curtailment during cold winter days.

Nuclear, oil-fired, and gas-fired plants with large spinning generators are at risk of decommission, potentially causing deficits of reactive power, system inertia, and frequency response. Without mechanical inertia from spinning generators and/or synchronous condensers, the New England system is increasingly at risk of cascading outage from contingencies.[12] While wind and solar generation can theoretically provide reactive power and frequency response, these are not current requirements in ISO New England.[13]

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[11] ISO New England. "ISO New England Inc. Transmission, Markets, and Services Tariff (ISO Tariff); Market Rule 1, Section 13 - Forward Capacity Market." Tariff. March 15, 2017. https://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1

[12] The External Market Monitor for ISO New England, Potomac Economics, Ltd., in its October 20, 2017 filing in this Docket at pages 11-12 notes: "In our role as IMM [Independent Market Monitor] for ISO New England, we also evaluated fuel supply contingencies and their impact on reliability in our *2016 Assessment of the ISO New England Electricity Markets.* Overall, our analysis revealed the essential role that both oil inventories and LNG play in ensuring fuel supply adequacy in winter. Any major reduction in the availability of either LNG or oil inventories could result in energy shortages in 2024. Unlike natural gas, the supply of these two fuels needs to be secured in advance, and they are stored on site. Although these resources are critical for responding to a major natural gas system contingency, they do not qualify as resilience resources under the [DOE-ordered] NOPR."

Notwithstanding the narrow scope of fuel types for which DOE seeks resilience pricing, Resilient Societies asks FERC to mandate expanded scope for fuel types qualifying as eligible for resilience pricing. New England will not escape future blackouts if FERC excludes LNG, fuel oil, and perhaps LNG plus gas pipelines as eligible sources of resilient fuels for on-site storage or dual-fuel availability in the ISO New England market.

[13] For an independent analysis of adaptive and flexible attributes of the various electric generation technologies, see Figure 27, "Comparison of Flexibility and Reliability Attributes of Power Generation Technologies" in Paul Hibbard, Susan Tierney, and Katherine Franklin, Electricity Markets, Reliability and the Evolving U.S. Power System, June 2017, at pp. 54-55.

In summary, Resilient Societies and other utility customers in New England are under threat of long-term loss of electricity supply due to defects in the electricity markets. These defects include inadequate price formation and resulting rates for generation capacity, "pay-for-performance" penalties during periods of fuel supply scarcity that do not incorporate societal costs of blackout, and capacity that clears auctions but is unlikely to assure "the delivery of energy and operating reserves when they are needed most."[14]

A feasible but rarely-used technology is co-location of electric generation plants with Liquefied Natural Gas (LNG) regasification plants, but this technology raises generators' costs and makes them less competitive in the Organized Markets. A potential resilient resource for New England is the Salem, Massachusetts gas-fired generation plant, which replaced a large coal-fired plant. Because an LNG export terminal is proximate to Salem, this plant might use re-gasified LNG as an energy source stored nearby. But without resilient capacity pricing rules and related auctions, such a concept is not presently financially viable.

While interstate gas pipelines remain in place, New England has experienced the sealing off of lateral service gas lines during a Polar Vortex period of high demand for office and residential heating. So as New England loses its major coal-fired generation facilities, and depends on gas pipelines that nearly collapsed the electricity market in February 2013 and again in January 2014, how can New England assuredly have system restoration capabilities in the future? Pricing of resilient energy stored on-site in organized capacity auctions could provide the answer.

Comments

Imperative for Electric Grid Resilience

A resilient electric grid will continue to operate during conditions of system stress and recover quickly if an unavoidable outage occurs. As the foundational attribute of electric power,

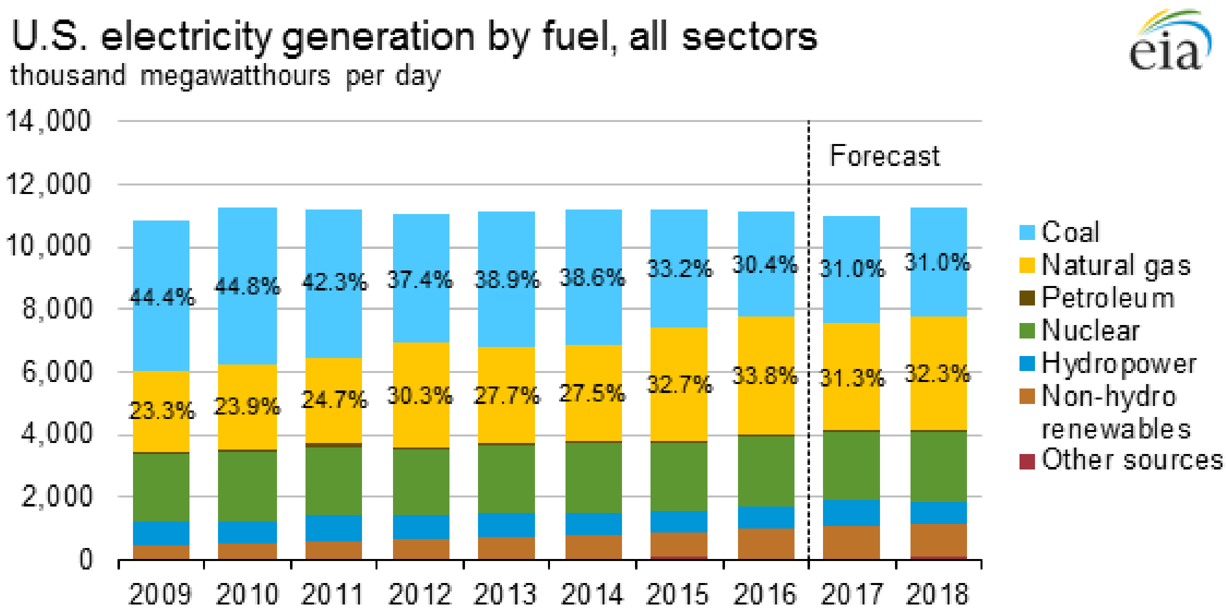
[14] ISO New England Internal Market Monitor, 2014 Annual Report, May 2015, Section 3.4.3.3 on "pay-for-performance designs."

generation resilience is a critical contributor to grid resilience; without resilient generation resources, prompt system restoration will not be possible, resulting in debilitation or total collapse of other infrastructures dependent on the electric grid such as telecommunications, water and sanitation, food storage and distribution, financial services, transportation, healthcare, and government services. When other critical infrastructures are debilitated, electric grid restoration will be vastly more difficult—and perhaps impossible before catastrophic impacts on human populations.

We commend the U.S. Department of Energy (DOE) for having the vision and fortitude to formulate a proposed rule that would greatly increase generation resilience. Unfortunately, the Organized Markets over the last two decades have operated without due consideration to generation resilience. The DOE proposed rule is a welcome and long overdue initiative to put the safety and security of the American people as a first priority. We applaud the Department of Energy's goals, but we differ as to the most efficient means of implementation.

Failure of Electricity Markets to Ensure Resilient Generation

Electricity markets in the United States, both within RTO/ISO and those traditionally regulated, are failing to adequately compensate entry and maintenance of generation resilient to interruptions in fuel supplies, such as coal, nuclear, and hydropower. Instead, natural gas generators, predominantly dependent on "just-in-time" fuel supplies, are expanding their share of generation.



Note: Labels show percentage share of total generation provided by coal and natural gas.

Source: Short-Term Energy Outlook, October 2017.

After issuance of FERC Order 888 in 1996, and with cheap natural gas from fracking, there has also been rapid reduction of dual-fuel capability. As we show later in this comment, the reduction in dual-fuel capability has been more rapid in Organized Markets than in Traditionally Regulated States. More gas-fired generation and less dual-fuel capability have resulted in a smaller proportion of generation resources with energy stored on-site. Because fuel transportation infrastructure may be disrupted by naturally-occurring disasters or deliberate attack, less energy stored on-site has resulted in less generation resilience and less overall resilience for the U.S. bulk power system.

Competition without well-formulated market rules has accelerated the shift to less resilient generation technologies, because the societal costs of potential blackouts, including costs from long-restoration times, are not fully included in price formation. A key feature of the market system under FERC Order 888 is neutrality among generation technologies. Nonetheless, generators resilient to fuel supply interruption compete with less reliable generators having lower costs or more government-provided subsidies. Coal-fired plants are burdened with the costs of compliance with environmental regulations. Government-mandated advantages for certain generation technologies include Renewable Portfolio Standards (RPS), renewable energy production tax credits, and investment tax credits.

Under current operation of competitive electricity markets, resilient generation technologies are severely disadvantaged. Resilient technologies include plants that have large quantities of energy (or "fuel") on-site, including nuclear, coal-fired, and hydroelectric plants. Dual-fuel plants—commonly those able to run on either natural gas or fuel oil—are also disadvantaged because the extra expenses for building and maintaining this capability are not adequately compensated in most regions.

We have read with interest the recent (October 20, 2017) filing submitted in Docket RM18-1-000 by Potomac Economics, Ltd., the designated Independent Market Monitor for the Midcontinent ISO (MISO), also serving as external market monitor for both New York ISO (NYISO) and ISO New England (ISO-NE). Potomac Economics claims that the MISO region under-assesses the value of prompt reserve generating capacity in that region.[15]

While the Organized Markets may seem to provide reliable electricity supply under normal circumstances, if a wide-area natural or man-made disaster were to hit, these defects in market operation would become obvious. A better course of action would be to fix market defects before tragedy occurs.

Facts and Figures on Diminished Generation Resilience

To quantify use of energy sources stored on-site and their effect on resilience, we obtained data collected by the U.S. Energy Information Administration (EIA) on Form EIA-860, including

[15] Potomac Economics, Ltd., the Independent Market Monitor for MISO, asserts that "market design issues" in MISO have impaired "price formation" and reduced "baseload resources that are needed…. This can cause them to retire [coal and nuclear plants] prematurely and undermine reliability. Fundamental problems in the design of the capacity market in MISO, for instance, have substantially reduced the net revenues of coal-fired and nuclear resources." Footnote 17 associated with these remarks states: "The most notable flaw in the MISO capacity market is that the demand for capacity in the planning resource auction does not reflect the reliability value of the capacity. To remedy this flaw, MISO must implement a sloped demand curve the [sic] reflects the rising value of capacity as the capacity margin falls." *Ibid*, p.14 and footnote 17 in the Potomac Economics filing. One needed element of incentive pricing, Potomac Economics states, is to increase the assumed Value of Lost Load ("VOLL").

data on primary, secondary, and tertiary energy sources. We generally defined generation plants with "energy stored on-site" as hydroelectric, nuclear, geothermal, coal-fired, petroleum-fired, and gas-fired with a backup fuel source such as fuel oil. We did not include wind and solar generators in the category of "energy stored on-site," because the wind does not always blow nor does the sun always shine—consequently these resources may not be available when they are needed most.

We compared nameplate generation capacity in 1996, the year FERC Order 888 was issued, to the most recent EIA data available for year 2015. We also compared generation capacity in the Traditionally Regulated States to the Organized Markets.

The EIA data tells us that in 1996—before establishment of organized electricity markets and before cheap natural gas from fracking—U.S. generation capacity was resilient to short-term fuel supply disruptions. Unfortunately, this resiliency has significantly declined in recent years:

- In 1996, 97% of U.S. generation capacity had its energy stored on-site, but by 2015 only 64% of capacity had its energy stored on-site.
- Only 27% of U.S. generation capacity added in 1997 and later has its energy stored on-site.
- Only 27% of U.S. gas-fired generation capacity added in 1997 and later is "dual-fuel."

We also used EIA data to compare generation capacity in Traditionally Regulated States to capacity in Organized Markets:

- In 1996, 98% of generation capacity in Traditionally Regulated States had its energy stored on-site while 97% of generation capacity in Organized Markets had its energy stored on-site.
- By 2015, 73% of generation capacity in Traditionally Regulated States had its energy stored on-site while 60% of generation capacity in Organized Markets had its energy stored on-site.

- In Traditionally Regulated States, 40% of generation capacity added in 1997 and later has its energy stored on-site, while in the Organized Markets, only 21% of generation capacity added in 1997 and later has its energy stored on-site.
- In Traditionally Regulated States, 42% of gas-fired generation capacity added in 1997 and later is “dual-fuel,” while in the Organized Markets, only 20% of new gas-fired generation capacity added in 1997 and later is “dual-fuel.”

The states of New York and Florida, with major blackouts in 2003 and 2008, respectively, appear to have incented their generation plants to maintain resiliency of energy sources:

- For New York in 1996, 99% of generation capacity had its energy stored on-site; by 2015, this proportion had declined only moderately to 81% of generation capacity having energy stored on-site.
- For Florida in 1996, 97% of generation capacity had its energy stored on-site; by 2015, this proportion had declined to 84% of generation capacity having energy stored on-site.

The states of California and Texas, having had major blackouts in 2011, nonetheless have dramatic declines in the proportion of generation capacity with energy stored on-site:

- For California in 1996, 97% of generation capacity had its energy stored on-site; by 2015, this proportion had significantly declined to 29%. Only 7% of new gas-fired generation added in 1997 and later is “dual-fuel.”
- For Texas in 1996, 88% of generation capacity had its energy stored on-site; by 2015, this proportion had significantly declined to 33%. Only 4% of new gas-fired generation added in 1997 and later is “dual-fuel.”

Fuel supply interruptions are not just a theoretical vulnerability. According to the 2017 “State of Reliability” report by the North American Electric Reliability Corporation (NERC), “lack of fuel” was the No. 2 cause of forced generator outages in 2014; in 2015 it was the No. 4 cause.

Imprudent market constructs and increasing penetration of gas-fired generation have exacerbated declining generation resilience. Rules for the Organized Markets commonly do not require bidders in the forward capacity markets to have firm gas supplies. Because of low price caps in most energy markets, market imposed penalties for generators that must pay high prices for gas in the spot market, or generators that cannot procure gas at any price, are a small fraction of societal losses from grid collapse and resulting long-term outages. And even if gas supplies were under firm contract, there is no system of mandatory reliability standards for the interstate natural gas transmission system. Increasingly, the natural gas transmission system and other industrial control systems are susceptible to cyberattack and other deliberate attacks.

Imported Energy Cannot Substitute for Resilient Generation

Within the Organized Markets, capacity markets commonly allow RTO/ISO to rely on imported energy—both electricity and "just-in-time" fuel for generation. Long-distance energy transmission systems can have common mode failures that cause electric grids to exceed the N-1 criterion—these include both extra high-voltage transmission substations with multiple circuits and interstate natural gas pipelines supplying multiple generators. Overreliance on systems with potential common mode failures makes using large quantities of imported "just-in-time" energy a risky everyday practice—and also increases vulnerability to physical attack, cyberattack, solar storms, and electromagnetic pulse.

In 2013, a FERC study reportedly determined that the bulk power system would collapse with loss of only nine high-voltage transmission substations in the continental United States. Interstate natural gas pipelines can also be single points of failure when multiple large-capacity generation plants are supplied by a single pipeline. For example, there are single gas pipelines in the U.S. that supply fuel for 5 GW or more of generation capacity. Loss of a single pipeline can cause loss of generation exceeding "N-1" contingency limits within control areas.

When energy for electricity is imported over long distances and used on a "just-in-time" basis, it causes vulnerability to short-term disruptions in supply. Consider our analysis using 2015 data from the U.S. Energy Information Administration (EIA):

Dependence on Imported Just-in-Time Energy for Electricity

Risk Rank	State	Electricity Consumed in 2015 (GW Hour)	Net Electricity Imports (Exports)	Electricity Generation Using Imported Natural Gas	Total Imported Energy for Electricity
1	Washington DC	12,099	100%	0%	100%
2	Rhode Island	8,200	15%	80%	96%
3	Delaware	13,016	40%	51%	91%
4	Massachusetts	59,367	46%	35%	81%
5	Nevada	38,479	(1%)	75%	74%
6	California	289,703	32%	36%	68%
7	Florida	256,344	7%	61%	68%
8	Vermont	5,885	66%	0%	66%
9	New Jersey	81,931	9%	45%	54%
10	Maryland	66,596	45%	7%	52%
11	Virginia	122,050	31%	20%	51%
12	New York	160,285	14%	35%	49%

Looking at the above table, it is easy to see that some regions are extremely dependent on imported just-in-time energy for electricity—particularly states within Northeast megalopolis from Boston to Northern Virginia. Also at risk are the individual states of Florida and California.

Of the states with a high reliance on imported just-in-time energy, we have empirical evidence that New York, Florida, and California are at particularly high risk, because they already have had major cascading outages in 2003, 2008, and 2011 respectively.

When each of the ISOs and RTOs projects its reserve margins for conditions of N-1 or N-2 contingencies, that region may rely on imported power from neighboring RTOs and ISOs. However, this planning criterion relies on the optimistic assumption neighboring control areas can deliver capacity as contracted, without any N-1 or N-2 contingencies of their own in effect. But in the real world, a solar storm can adversely affect all of North America; a cyberattack can cross the regional boundaries of the Reliability Coordinators; and a high-altitude electromagnetic pulse attack can impact most of the continental United States. So these fictitious planning assumptions provide an aura of reliability for RTO/ISO but ignore common-mode and coincidental failures that impact electricity generation and power imported over long-distance transmission systems.[16]

Insufficient Capacity to Provide Essential Reliability Services

Increasing use of imported capacity, wind generation, and solar photovoltaic power (PV) is causing shortages of local frequency response, mechanical inertia, and reactive power—so-called "essential reliability services" (aka, "ancillary services") that were once provided by hydroelectric power plants and thermal generators. Reactive power necessary for voltage support cannot be effectively imported over long distance transmission lines. Wind turbines and solar PV are non-dispatchable and therefore unreliable for blackout restoration. Current design of capacity markets—and accompanying markets for essential reliability services—do not adequately take into consideration reliability risks and potential societal costs from inability to generate essential reliability services beyond the administratively set levels.

General Comments on Proposed Rule

Why do Organized Markets suffer from decline in energy stored on-site for electric generation during contingencies? A key reason for this defect in price formation is the low occurrence frequency (or zero prior occurrence frequency) of wide-area, long-term blackouts. The result of this "nothing bad has happened yet" regulatory structure is overdependence on "just-in-time" energy from both long-distance electricity transmission systems and natural gas pipelines. If regulators assume that distantly-generated electric power will always be reliably transmitted, and that interstate gas pipelines with electric compressors and other infrastructure interdependencies will continue to function during blackouts, then generation reserve margins will be built on foundations of sand. Adding risk, policymakers may believe it is prudent to expand rapidly the share of renewable generation—capacity that is not dispatchable and that is

[16] For an overview of common mode failure hazards that may concurrently impact the North American electric grid, see the InfraGard Electromagnetic Pulse Special Interest Group book, *Powering Through: From Fragile Infrastructures to Community Resilience, Version 1.0,* December 2016.

presently supported by miniscule electric storage capabilities. When a high-impact, low frequency event (such as solar storm, cyberattack, or electromagnetic pulse attack) causes a wide-area blackout that cannot be promptly restored, the defects of the current regulatory system will become plain for all to see.

The rule proposed by the Department of Energy identifies real issues for grid resilience and presents a particular potential solution—compensation for 90 days of energy (or "fuel") stored on-site at electric generators. Unfortunately, some interests now pick apart the DOE proposal as unworkable—i.e., "blowing up the markets."[17] We instead take the approach of building on the DOE proposal, preserving the intent while offering market-based elaborations that would increase operational flexibility and allow a wider range of generation resources to participate.

The DOE proposed rule would compensate individual generators that have 90 days or more of energy (or fuel) stored on site. A cost-of-service compensation system based on energy inventory stored on-site could be an improvement over the current system, where the resilience of energy stored on-site is minimally valued in price formation. But the costs of such potential distortions of capacity markets cannot be dismissed as a trivial harm. As the Independent Market Monitor for the PJM Interconnection system observes, "subsidies are contagious."

If most coal-fired generation cannot compete in competitive markets, and most nuclear power plants also cannot compete, were regulators to set the "resilience price" for fuel stored on-site so high that all the coal and nuclear facilities would remain in operation, these subsidies could impair future investments in gas-fired generation plants. Gas-fired plants have important attributes for system restoration, including quick startup, fast ramping, and load-following. In many instances gas-fired plants have access to multiple pipelines, providing valuable fuel supply resilience.

[17] In fact, the electricity markets have been "blown up" already by dozens of special interest mandates and subsidies, as became clear during the May 1-2, 2017 FERC Technical Conference on wholesale markets, FERC Docket No. AD17-11-000.

We alternatively propose a technology-neutral solution that will allow all generating capacity with reserve fuel stored on-site (or nearby) to participate, including generating plants with dual-fuel capability. We also suggest a significant modification to the DOE-proposed rule: instead of a requirement for 90 days of on-site fuel at individual generators, we suggest that each RTO/ISO should have a total goal for energy inventory stored on-site at generation plants.

Each of the regions should, at the outset, assess the energy resilience requirements that they propose to adopt, subject to review and approval by FERC. We already have *a fortiori* evidence that the capacity to operate with energy inventory stored on-site is important. What is that evidence? First, it is the well-documented inability of generators to procure natural gas and fuel oil during the Polar Vortex events in New England and elsewhere. Second, it is the more recent events after hurricane Maria in Puerto Rico. We now know that between the onset of a Category 5 hurricane reaching the island of Puerto Rico on September 20th and the 30th day of recovery efforts on October 20th, 2017, more than 80 percent of the roughly 3.4 million residents of Puerto Rico remained without regular electric service and at least 30 percent of the population remained without public water service. Fuel distribution for backup electric generators was hampered by a crippled transportation network.[18]

Why are these indicators of impaired grid restoration relevant, when Puerto Rico is not even subject to FERC jurisdiction? When 30 days of blackout for millions of U.S. citizens has been demonstrated, we must assume that a national emergency could likewise cause a long-term blackout for the continental United States. At a minimum, we need some electric generation that can operate far past a thirty day emergency window. Puerto Rico provides a glimpse into what might happen in the continental United States if a natural disaster, such as a severe solar storm, or man-made cyber-attacks, or combined arms cyber and electromagnetic pulse (EMP) attack were to occur.

[18] Respaut, Robin, Graham, Dave, and Resnick-Ault, Jessica. “For desperate Puerto Ricans, fuel a precious commodity.” *Reuters*, September 27, 2017. https://www.reuters.com/article/us-usa-puertorico-fuel/for-desperate-puerto-ricans-fuel-a-precious-commodity-idUSKCN1C216B

We propose that each of the RTO/ISO assess a prudent requirement for the total energy inventory to be stored on-site at generators within their service areas. For example, after assessing loads from industrial electricity users and home consumers, an RTO/ISO might determine that historical peak load has been approximately 100 gigawatts, but that basic societal functioning could continue at a load of 50 gigawatts. Moreover, an RTO/ISO might determine that the summer months of June, July, and August (a period of approximately 90 days for the three months) are the season of peak consumption. Under a new compensation scheme to promote resilience, the RTO/ISO could then procure 90 days of energy inventory stored on-site to generate at least 50% of peak energy consumption during the summer months, at generation sites with no less than 50 gigawatts of combined nameplate capacity.

A simple compensation system with only one time bucket of energy inventory might unduly advantage generators that routinely store large quantities of fuel on-site, such as coal-fired and nuclear plants, but are unable to convert their fuel into electric energy in the first hours or days after a grid collapse. For example, a coal-fired steam turbine plant typically requires 12-24 hours to generate electricity from a cold start and therefore may be unable to contribute to grid restoration immediately after a grid collapse. Likewise, when nuclear power plants have emergency shutdowns during grid collapse (so-called "SCRAMs"), neutron poisoning from xenon in their reactor cores, combined with startup delays, can prevent full contribution to load for a week or more. In contrast, hydroelectric plants can contribute to load within seconds of being called for dispatch and combustion gas turbines can contribute to load within about 20 minutes. Significantly, hydroelectric and gas-fired plants have quick-dispatch, ramping, and load-following capabilities that most coal-fired and nuclear plants do not.[19]

To allow more prompt grid restoration, greater operational flexibility, and ability for more generation technologies to participate in compensation for energy inventory stored on-site, we further propose three or more time buckets of energy inventory—for example, inventory that can generate electric energy anytime within 1 to 7 days of a grid collapse, energy inventory that

[19] Due to the value of gas-fired plants in grid restoration, FERC should consider if plants with firm contractual commitments for line-pack gas might be considered as having energy stored "on-site."

can generate electric energy within 8 to 30 days of a grid collapse; and energy inventory at generators that can operate even 31 to 90 days after a grid collapse.[20]

Again, a key part of our proposal is that RTO/ISO subdivide total energy inventory stored on-site at generators into both capacity and time buckets—for example, fast-recovery generation capacity (operating within 1 to 7 days of a blackout); mid-term resilient generation capacity (capable of operating for 8 to 30 days); and long-term resilient generation capacity (capable of operating for 31 to 90 days or longer). Within each time bucket, the RTO/ISOs could set stored energy goals measured in days of operation at a set gigawatt output, or alternatively, measured in gigawatt hours.

An annual energy inventory market could allow generators to bid gigawatts hours of energy inventory to be operated at a specified generation outputs and in specified time windows and seasons. For example, a gas-fired generator with dual-fuel capability might bid 2.4 gigawatt hours of energy inventory for operation at 100 MW for any 24 hour dispatch period during the 1 to 7 day time bucket. A coal-fired generator might bid 240 gigawatt hours operating at 500 MW for 480 hours (20 days) during the 8 to 30 day time bucket. A nuclear plant might bid 1,440 gigawatt hours operating at 1,000 MW for 1,440 hours (60 days) during the 31-90 day time bucket. All of these bids might be for the summer generating season—June, July, and August.

For each time bucket, the RTO/ISO would set an auction quantity for total energy inventory to be stored on-site at generators. As with other RTO/ISO markets, bidders would be paid the highest clearing price. Hence, this auction would be a basis for just and reasonable rates while being technology-neutral. In contrast, the alternative of requiring a single time-period for generation fuel stored on-site, the 90 days or more that the Department of Energy has proposed, could be considered by courts as arbitrary and capricious, and incapable of meeting

[20] Regulators should not rule out a fourth category: generating facilities that directly serve Tier 1 national security facilities that are dependent upon 24/7 electric service for vital military or intelligence operations. If there is a class of priority customers who will require resilient electric generation for more than a 90 day period, the recognition of these market requirements might encourage the development and licensing of small, modular, walk-away safe nuclear reactors.

the legal requirements of both the Administrative Procedures Act and the Energy Policy Act standards in Section 215 adopted in year 2005.[21] The mechanics of auction markets for energy inventory stored on-site at generators would be approved by FERC orders.

Responses to FERC Question Prompts

Our comments are below, organized by the question prompts provided by FERC.

Need for Reform

1. 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?

We propose this definition for electric generation resilience:

> *Resilience is the ability of a generation resource to deliver services under conditions of both short and long-term system stress, and recover quickly following a blackout, including when one or more critical infrastructures are debilitated. Generation services include electric energy, frequency support, voltage support, reactive power, dispatch, ramping, spinning reserves, operation in load-reject mode, and blackstart energy. System stress includes naturally-occurring events such as geomagnetic disturbance, hurricanes, tornados, earthquakes, floods, tsunamis, and wildfires. System stress also includes man-made events such as physical attack, cyber-attack, and electromagnetic pulse. Debilitated critical infrastructures include the electric grid itself, and other*

[21] Section 215 of the Federal Power Act. We acknowledge that the Secretary of Energy, since the FAST Act enactment in December 2015, has parallel emergency powers to require emergency actions, order interconnections, and otherwise provide cost-recovery for a "grid security emergency" including emergency order fulfillment over sequential 15-day periods, assuming the President re-authorizes an energy emergency for sequential 15 day periods. See 16 USC 824o-1 (2015) and 81 FR 88136 (2016). But the Secretary of Energy lacks authority to determine in advance that there are 90-day energy emergencies under Section 215A of the Federal Power Act. So under Section 215A, on its face the determination of a need for exactly 90 days or more of on-site fuel availability may be held by courts to be arbitrary and capricious.

infrastructures that enable generation such as fuel storage and distribution, transportation, communications, and water supply. One contributor to generator resilience is days of electric energy available during periods of critical infrastructure debilitation, especially when debilitation of the transportation sector interrupts resupply of fuel.

The National Infrastructure Advisory Council (NIAC) proposes this alternative definition of resilience:[22]

"Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."

We reiterate this definition for reliable operation, as specified in Section 215 of the Federal Power Act.

"The term 'reliable operation' means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Reliable operation is a superset of system resilience, because the bulk power system should be operated within voltage and stability limits. During an unanticipated failure of system elements that causes a blackout, the zero voltage condition is a violation of voltage limits.

In regard to the levels of resilience and reliability that are appropriate, a common informal standard for Loss of Load Expectation (LOLE) is one day of outage per ten years of operation.

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[22] National Infrastructure Advisory Council, "Critical Infrastructure Reliance Final Report and Recommendations." Report. September 8, 2009. https://www.dhs.gov/xlibrary/assets/niac/niac_critical_infrastructure_resilience.pdf

However, there is no widely accepted standard for system resilience. As the proposed rule envisions, one resilience standard might be the days of electric energy available from energy (or "fuel") stored on-site at generators. Another resilience standard might be the ability to meet established restoration time objectives following a high-impact, low frequency event such as physical attack, cyberattack, geomagnetic disturbance, and high-altitude electromagnetic pulse. Standards for the levels of resilience and reliability—in addition to the proposed classes (1-7 days; 8-30 days; 31-90 days; and more than 90-day requirements for energy inventory stored on-site)—may be addressed by FERC through the Section 215 procedure for reliability standards.

Resilience is not properly valued within the RTO/ISOs market mechanisms for price formation. The majority of essential energy and ancillary reliability services are implicitly supplied through operation of the energy markets. In some cases, RTOs/ISOs operate separate markets for ancillary services such as reactive power or spinning reserves. Markets for ancillary services have capacities that are administratively determined—and the set capacities are far below the total implicit supply of ancillary services provided by large spinning generators such as coal and nuclear plants.

With rare exception, RTO/ISO markets likewise do not properly value or explicitly remunerate fuel resilience such as fuel-stored on-site or dual-fuel capability. Penalties for non-performance in capacity and ancillary services markets are typically a fraction of total contract fees—in fact, it can be profitable for generators to bid non-reliable and non-resilient capacity and simply pay penalties on the chance that capacity or services cannot be delivered when needed. These market distortions need to be corrected. With existing defects in price formation, when reliable and resilient coal and nuclear plants retire, the bulk power system loses the benefits of these generators.

2. 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?

We have addressed Polar Vortex hazards to New England previously.

3. 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?

The 2014 Polar Vortex and hurricanes Irma, Harvey, Maria, and superstorm Sandy are real-life examples of system stress caused by weather. However, weather-related events are just one category of many events that may cause system stress. Other sources of system stress include physical attack, cyberattack, geomagnetic disturbance, and high-altitude electromagnetic pulse. Therefore, it would be a mistake for the Commission to formulate a narrow rule principally around weather-related risks.

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?

The proposed rule for 90 days of energy inventory stored at generation sites, if appropriately modified to include several classes for resilient generating capacity and also modified to be technology-neutral, would significantly improve the time required for system restoration after extreme events. With ample energy inventory for generation, dispatchable resources are more likely to be available. After an extreme event, multiple critical infrastructures will be debilitated—including refineries, fuel storage, the transportation system necessary for fuel delivery, and the telecommunications system necessary to coordinate and control fuel resupply. Severe damage to the transmission and distribution system would exacerbate debilitation of critical infrastructures necessary for fuel resupply.

4. 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 coal-fired plants typically store 60 to 100 days of fuel on-site, and because nuclear power plants have several years of fuel stored in their reactor cores, the retirement of coal and nuclear resources has had significant impact on reliability and resilience in the RTOs/ISOs.[23] Having large-capacity generators or several units at a common facility provides scale economies that are often associated with above-average cyber and physical plant protection. These plants also provide spinning inertia that is not provided by renewable generation. Because current RTO/ISO market constructs do not adequately value resilience, we foresee accelerating coal and nuclear plant retirements causing further diminishment of resources with fuel stored on-site.

5. 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?

Fuel diversity is a commonly used proxy for resilience and reliability. However, a RTO/ISO with fuel diversity may still lack resilience and reliability. For example a system dependent on just-in-time deliveries of natural gas for generation, coal plants fired by a specific type of coal mined only in distant locations, or hydropower in a region susceptible to drought may have fuel diversity but lack resilience and reliability. The measure of days of energy stored at generator

[23] It is notable that the Independent Market Monitor for the Midcontinent ISO (MISO), Potomac Economics, Ltd. finds that multiple gas pipelines provide substantial resilience for MISO gas generation, but "[t]o the extent MISO has had long duration fuel security-issues, the issues have been with coal supply limitations due to railway congestion." The Potomac Economics filing in this Docket on October 20, 2017, at page 7 fn 5, cites flooding that disrupted coal transport from the Powder River Basin in year 20008, prompting restrictions on MISO coal generation, and ice-derived barge congestion affecting coal deliveries in Michigan in year 2014, and coal delivery constraints in summer and fall of 2014 due to competition for rail cars by shippers of Bakken crude oil.

sites would be a better metric for resilience than measures of fuel diversity (such as the Herfindahl-Hirschman Index applied to fuel diversity).[24]

We have good quantitative evidence that current policies for management of RTO/ISO markets have had a negative impact on resilience, because the proportions of generators with fuel stored on-site have declined markedly since the implementation of Organized Markets starting in 1997:

- In 1996, 97% of generation capacity in Organized Markets had its energy stored on-site.
- By 2015, 60% of generation capacity in Organized Markets had its energy stored on-site.
- In the Organized Markets, only 21% of generation capacity added in 1997 and later has its energy stored on-site.

Eligibility

General Eligibility Questions

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

Specific services should be specified in the FERC rule. For example, FERC may determine that each RTO/ISO will require that the generation system as a whole will have 90 days of energy stored on-site at an administratively determined fraction of peak capacity. The triggering and termination mechanisms for provision of compensation could be reports to the U.S. Energy Information Administration (EIA) of energy inventory stored on-site at specific generators.

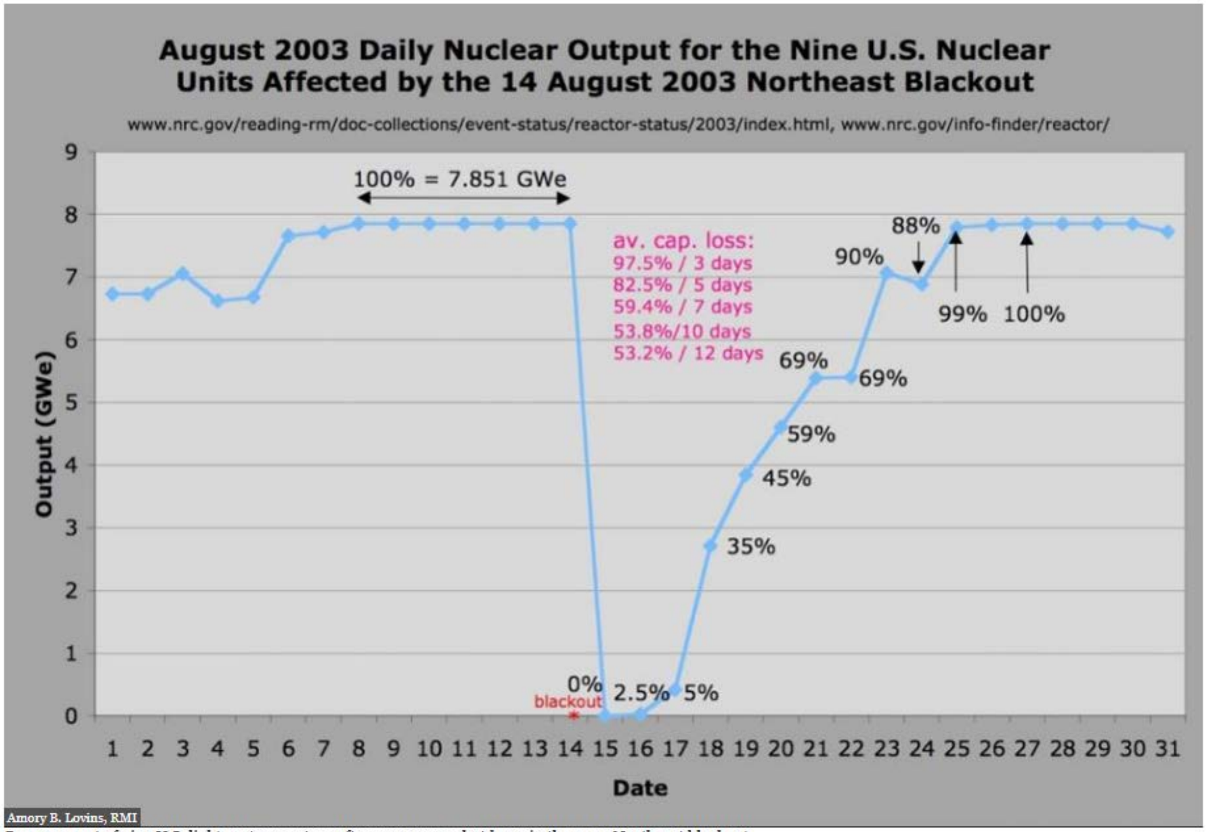
2. As the proposed rule focuses on preventing premature retirements, should a final rule be limited to existing units or should new resources also be eligible for cost recovery? Should it also include repowering of previously retired units? Alternatively, should there be a

[24] See Albert O. Hirschman, "The Paternity of an Index," *American Economic Review* (Sep. 1964), 761-62. See also Eunju Jun, et al. "The analysis of security cost for different energy sources," *Applied Energy* (2009), 10:1894-1901, and B. K. Sovacool, et al. "Evaluating energy security performance from 1990 to 2010 for eighteen countries," *Energy* (2011) 36: 5846-5853.

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?

The rule proposed by the Department of Energy (DOE) envisions compensation to individual generators with 90 days or more of energy stored on-site. We propose an enhancement that could provide greater flexibility and also greater resilience: compensation to generators for days of energy inventory on site, even below a 90-day limit at specific generators, but with the target of 90 days of total energy reserves for some portion of resilient generating capacity in each RTO/ISO system taken as a whole. Under this methodology, a hydropower generator with 30 days of water in the reservoir would be compensated, as would a coal-fired plant with 60 days of fuel in a coal pile, as would a nuclear plant with 90 days or more of fuel in its reactor core. Likewise, a dual-fuel plant could be compensated for 3 days of fuel oil in its tanks.

Payment to dual-fuel generation plants is a key aspect of our proposal. Dual-fuel plants have blackstart, ramping, and load-reject capabilities that coal-fired and nuclear plants lack—and these services can be necessary in grid restoration. Moreover, after a system collapse necessitates emergency reactor shutdowns at nuclear plants (SCRAM's), nuclear reactors cannot restart for several days due to neutron poisoning from xenon and even after restart run at limited power. The record of daily nuclear output for reactors in the aftermath of the August 2003 Northeast Blackout makes this clear:



Power ascent of nine U.S. light-water reactors after emergency shutdown in the 2003 Northeast blackout.

Graph source: Amory Lovins, Rocky Mountain Institute[25]

For the first days of a blackout—the very time period that is most critical for grid restoration—nuclear plants will be unable to supply electric energy. But in the long-term, with the transportation sector still potentially disrupted, the long-term fuel supplies in reactor cores could be critical for societal functioning.

The proposed DOE rule does not specify how days of "fuel" on-site would be calculated. There are multiple potential methodologies with dramatically different results. Would the days of fuel be calculated at generation operation at nameplate capacity, summer capacity, winter capacity, or average capacity delivered over some previous time period? Would generators with very low capacity factors achieve advantages in compensation by maintaining they have many days of

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[25] Lovins, Amory. "Does 'Fuel On Hand' Make Coal and Nuclear Power Plants More Valuable?" *Forbes*, May 1, 2017. https://www.forbes.com/sites/amorylovins/2017/05/01/does-fuel-on-hand-make-coal-and-nuclear-power-plants-more-valuable/4/#33b47bd513e2

fuel on-site, based on days of fuel calculation that has a low figure for fuel consumed per *average day*? An "average day" or capacity factor calculation would result in a greater figure for days of fuel on-site than a "nameplate capacity" calculation.

Our proposal would avoid the complications of calculating days of "fuel" on-site for individual generators and instead use the more relevant figure of days (or hours[26]) of energy inventory for the RTO/ISO system as a whole. For example, suppose an ISO that typically consumes 150,000 gigawatt hours of energy during the peak summer months of June, July, and August. These three months cover approximately 90 days. Therefore, the ISO target for energy stored on-site would be an administratively determined fraction of 100,000 gigawatt hours necessary to preserve basic societal functioning—for example 50% of 150,000 gigawatt hours or 75,000 gigawatt hours.

Each generator could report on a quarterly basis the average number of gigawatt hours of energy inventory on-site during the previous 90 days. Compensation for generators could be based on one or more administratively set fee(s) per gigawatt hours of energy from energy inventory on-site for quarterly time periods of storage. The fee for energy to be supplied in the first seven days of system stress—when the value of on-site stored energy for system restoration would be very high—could be a multiple of the fee for energy to be delivered in days 8 through 90 of system stress.

Alternatively, a market mechanism might be used: generators might bid a price for gigawatt hours of energy from energy inventory on-site for a specified time period and season of storage, until the market is cleared. As with existing energy markets, bidding participants would be paid the highest clearing price. There might be one market for resilient on-site energy to be supplied in days 1 through 7, another market for days 8 through 30, and yet another market for days 31 through 90. The supply curves and bidders for these time periods could be vastly different. For example, gas-fired plants with dual-fuel capability could be the predominant

[26] Because RTOs and ISOs commonly manage electricity markets in measures of gigawatt "hours" or megawatt "hours," instead of "days," we suggest that hours be used as the temporal quantity in any final rule.

bidders in the 1 through 7 day market, while coal and hydroelectric plants might be the predominant bidders in the 8 through 30 day market, and nuclear plant operators might be the predominant bidders in the 31 through 90 day market. Importantly, to prevent nuclear operators (or other operators with on-site energy inventories in excess of 90 days) from bidding more energy into the market than their plants can generate with nameplate capacity, the maximum bid quantity for any plant should be limited. An appropriate calculation for the limit would be the energy the plant could produce at nameplate capacity within the requisite time period.

3. Are there other technical characteristics that should be required for an eligible unit besides on-site fuel capability? If so, what are those technical characteristics and what benefits do they provide? What types of resources can meet the proposed eligibility criteria of the proposed rule? What proportion of total current generating capacity does this represent?

Generation plants should not receive more compensation from resilient energy inventory than their plants can feasibly generate. For example, if a generation plant requires 1 day of downtime for each 19 days of operation, the gigawatt hours of energy inventory bid by the plant should be reduced by a factor of 5% (1 day/20 days). It is likely that coal-fired plant, nuclear plants, and hydroelectric plants will fill most of the administratively set quantities under the rule as proposed by DOE because these technologies typically have large quantities of fuel stored on-site. Using the most recent EIA data available, we estimate that plants of these three categories represent 42% of nameplate generation capacity in the Organized Markets. See below table:

United States Generation Capacity by Primary Energy Source—2015						
	Gigawatts			Percent of Total Generation		
Primary Energy Source	All Areas	Organized Markets	Traditionally Regulated Markets	All Areas	Organized Markets	Traditionally Regulated Markets
Natural Gas	488.2	340.9	147.2	42.8%	44.1%	40.1%
Coal	302.0	211.5	90.4	26.5%	27.4%	24.6%
Nuclear	103.9	69.4	34.5	9.1%	9.0%	9.4%
Hydropower	96.4	40.3	56.1	8.5%	5.2%	15.3%
Wind	73.3	59.0	14.3	6.4%	7.6%	3.9%
Petroleum	37.9	25.8	12.0	3.3%	3.3%	3.3%
Renewable Fuel	18.9	12.4	6.5	1.7%	1.6%	1.8%
Solar	13.7	8.7	5.1	1.2%	1.1%	1.4%
Other Gas	3.7	3.3	0.4	0.3%	0.4%	0.1%
Misc. Other	2.2	1.4	0.8	0.2%	0.2%	0.2%
Totals	**1,140.1**	**772.7**	**367.4**	**100.0%**	**100.0%**	**100.0%**
Note: Division of Organized Markets and Traditionally Regulated Markets based on state boundaries. Operable capacity only.						

4. 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?

The rule should be technology-neutral and not discriminate among generation sources that are able to operate from energy sources stored on-site (or in the close proximity of the generator). Because our proposal would allow compensation for gigawatt hours of energy inventory on-site, it is likely that hydroelectric (including pumped storage), geothermal, dual-fuel with adequate on-site storage, gas-fired with nearby LNG regasification, coal-fired, and nuclear plants would qualify under the rule. Because gas-fired plants have valuable technical characteristics for blackstart, ramping, and load-reject during system restoration, the

Commission should also consider whether gas-fired plants with dedicated line-pack under firm contract could qualify as having "fuel stored on-site."

5. 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?

Compensation for essential energy and ancillary reliability services should not necessarily be tied to energy inventory on-site, although technologies that have commonly have energy stored on-site may routinely provide these services. The list of essential energy and ancillary reliability services under a proposed rule may include:

1. Blackstart
2. Operation under load-reject
3. Reactive power
4. Voltage support
5. Frequency support
6. Spinning reserves
7. Dispatchability

6. 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?

Section 215 of the Federal Power Act has a "savings clause" that protects substantial state autonomy with respect to intrastate transmission and distribution systems. The regulated markets also provide rate of return regulation for various generation capabilities in those markets. FERC should leave these other markets as they now operate. The Congress may at some point consider additional legislation governing investments in and cost recovery for needed grid resilience throughout the nation.

90-day Requirement

1. 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?

As explained above, defining eligibility at the plant level based on 90 days of fuel supply for the specific plant is likely to exclude resources that could substantially contribute to resilience in the first few days after grid collapse, such as dual-fuel plants with just a few days of fuel supply. A 90 day requirement would provide unfair advantage to nuclear plant operators that always have 90 days of fuel stored on-site, but cannot operate at full capacity in the first week after SCRAM due to neutron poisoning from xenon. It would be far more flexible, perhaps less expensive, and be more likely to enhance resilience, to calculate the 90 days of energy inventory on-site based on a system-wide fraction of peak load within an entire RTO or ISO. The 90 day requirement could be found by courts to be arbitrary and capricious. We have articulated potential benefits were the various RTOs and ISOs to adopt multiple classes of days of on-site fuel capacity, not just a 90 day requirement.

Some RTO/ISO have worked themselves into a position where 90 days of energy inventory on-site for the system will be very difficult to attain. For example, the state of California, served principally by CAISO, typically imports approximately one-third of electric energy consumed in a given year. For California, another third of electric energy is supplied by gas-fired plants with minimal fuel stored on-site. California has only two remaining nuclear plants, Diablo Canyon Unit 1 and Unit 2, and these plants are slated to close in 2024 and 2025, respectively. Solar and wind power for California are non-dispatchable and therefore non-resilient. A rule compensating generator energy stored on-site would likely result in widespread installation of dual-fuel capability and LNG regasification plants in California.

2. 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?

Commonsense would say that more energy stored on-site at generators will result in more resilience and reliability, especially when transportation infrastructure could be debilitated by natural disaster or man-made events. We cannot exclude the hypothesis of diminishing returns to increments of fuel stored on-site. Empirical analyses would be beneficial. For past evidence, we refer to the 2017 "State of Reliability" report by the North American Electric Reliability Corporation (NERC), where "lack of fuel" was the No. 2 cause of forced generator outages in 2014; in 2015 it was the No. 4 cause. A fraction of average load in a peak consumption season (such as the summer season), combined with 90 days of operation for some portion of generating capacity, would result in a prudent duration of energy inventory on-site. There may be higher returns to resilient capacity investments for additions to substantially shorter periods of fuel storage on-site.

The Communications Dependency on Electric Power (CDEP) Working Group of the National Security Telecommunications Advisory Council (NSTAC) conducted a study that considered events that might result in outages of one year or more and affect multiple ISOs.[27] A 90 day fuel supply would be a major benefit in averting long-term outages (LTOs) of concern to NSTAC.

The lack of statistical studies showing that the presently impudent practices for generator resilience have not yet resulted in large economic losses or widespread human deaths is no excuse for putting aside proposed DOE rule.

Fuel Supply Requirement

1. The proposed rule requires that resources must be in compliance with all applicable environmental regulations. How should environmental regulations be considered when

[27] "Communications Dependency on Electric Power Working Group Report, Long-Term Outage Study," February 2009.

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?

42 U.S. Code § 7545—"Regulation of fuels" contains provisions for wavier of environmental regulations for fuel use during "circumstances are the result of a natural disaster, an Act of God, a pipeline or refinery equipment failure, or another event that could not reasonably have been foreseen or prevented." Moreover, the FAST Act, adopted as Section 215A of the Federal Power Act, provides a waiver from liability for inadvertent violation of environmental regulations to fulfill emergency orders issued by the Secretary of energy during a declared "energy emergency" with the waiver enabled for a period of 90 days. Therefore, the DOE rule as proposed is compliant with existing environmental regulations if responding to a declared emergency certified by the President and the Secretary of Energy.

2. 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?

A penalty system for non-performance during emergency conditions could be appropriate incentive to avoid conditions that may affect on-site fuel supply. However, the penalty should be large enough to garner the attention of utility executives—perhaps a multiple of the annual fees received by generators.

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

As described above, some regions such as California and New England have, over decades, drifted into difficult situations due to extreme imprudence regarding energy inventory on-site at generators. To protect human populations in these regions, the proposed rule is all the more necessary.

Implementation

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

Our above proposal for a variety of resilient capacity products allows both compensation for increased resiliency, through market auctions, and continued dispatch under existing market conditions.

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

Any cost-based compensation for energy inventory on-site should be distinct and separate from regional capacity markets. Costs of fuel storage for blackstart of designated generators are already allowed under Section 205d of the Federal Power Act.

3. 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?

We would expect that new and existing generation resources that have capability to store large quantities of fuel on-site would increase their share of capacity, but with significant variations by region. Retirement of existing resources with capability for fuel stored on-site would likely be reduced, if the remuneration is significant in comparison to operating and maintenance expenses.

4. 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?

Yes, there should be performance requirements. Performance should be determined by certification to the U.S. EIA that a requisite gigawatt hours of energy has been stored on-site for the previous quarterly period; and other qualifying standards should be adopted by the RTOs and ISOs and be subject to FERC review and approval. The consequence of not meeting the performance requirement should be a penalty that is a multiple of compensation.

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

We generally support market-based auctions for resilient generation. However, there may be ancillary requirements that are more efficiently procured by cost-of-service compensation, such as fuel stored on-site for system restoration (blackstart) contingencies. Protection of "cranking paths" and other investments in resilient transmission are generally subject to cost-of-service regulation even within RTOs and ISOs. Regulations to preclude "double dipping" compensation may be required.

Rates

1. The proposed rule lists compensable costs that should be included in the rate as operating and fuel expenses, costs of capital and debt, and a fair return on equity and investment. Are there other costs that would be appropriate to be included in the rate? Would any of the listed costs be inappropriate for inclusion?

The list of compensable costs in the proposed rule is appropriate for cost-of-service resilient services. However, the consumer is generally better protected through the use of capacity auctions, so that inefficient provider-bidders may not be among those selected in competitive markets to provide the resilient services that are put out for capacity bidding.

2. Should wholesale market revenues offset any cost of service payments stemming from the proposed rule?

We lack information as to the mix of services that will be allowed as cost-of-service versus competitive market services. However, if our proposed rule of separate bids for resilient pricing were implemented, plant owners could receive wholesale electricity revenues and also auction revenues for energy inventory stored at generation sites. Both revenue sources could be considered in investment and operation decisions.

3. How should RTOs/ISOs allocate the cost of the proposed rule to market participants?

For market-based remuneration, costs might be allocated by the same method used to allocate costs of the RTO/ISO capacity market. As an alternative to ratepayer-funded compensation, federally funded compensation may be appropriate for energy inventory stored on-site that supports Tier 1 defense and other national security installations; these expenses could be considered an expense related to national security. Overall, the use of competitive market bids, by annual or seasonal auctions, should generally fulfill requirements more efficiently than through federal subsidies or cost-of-service regulation intruding into the largely deregulated generation sector.

4. How would the requirement that eligible resources receive full cost recovery be reconciled with the requirement, as stated in the regulatory text, that resources be dispatched during grid operations?

We generally prefer market-based acquisition of resilient capabilities and services. In these markets, some providers may do so at a profit and others may do so at a loss, both impacting future auction bids and prices of services accepted.

Other

1. The proposed requirement for submitting a compliance filing is 15 days after the effective date of any Final Rule in this proceeding, with the tariff changes to take effect 15 days after the compliance filings are due. Please comment on the proposed timing, both to develop a mechanism for implementing the required changes and to implement those changes, including whether or not such changes could be developed and implemented within that timeframe.

Because high-impact, low frequency events may occur at any time, and because such events could represent an existential threat to the United States, the proposed rule should be implemented without delay. We agree that the proposed timeframe is an appropriate goal for interim resilient capacity services to be provided on an *interim basis*. The regional RTO and ISO markets may require adoption of various resilient products in phases. If FERC orders the RTOs and ISOs to develop fast-track capacity markets for resilient services, this will require some additional time for designation of initial auction products, then for FERC review and approval, before auctions actually commence within the RTOs and ISOs. FERC may appropriately order fast-track development of these services because an emergency does exist and because prompt and visible resilient service enhancements may enhance deterrence by malevolent actors and affiliated foreign governments.

2. Please comment on the proposed rule's estimated burden of $291,042 per respondent RTO/ISO, to develop and implement new market rules as proposed, including the potential software upgrades required to do so.

The estimated compliance burden would be trivial compared to the lost GDP and impact on human populations from a long-term, wide area blackout caused by inadequate generation resilience.

3. Please describe any alternative approaches that could be taken to accomplish the stated goals of the proposed rule.

We have described above various alternative approaches that would require different classes of resilient capacity services, including but not limited to 90 days of energy inventory on-site for RTO/ISO systems taken as a whole, instead of 90 days of fuel stored on-site for individual generators. We have also encouraged consideration of 1 to 7 day; 8 to 30 day; 31 to 90 day; and perhaps longer endurance generating capabilities, such as walk-away safe modular nuclear reactors. A "resilience product" based on energy inventory stored on-site at generators could be implemented through market mechanisms.

4. What impact would the proposed rule have on consumers?

Initially, consumer costs would rise. However, with market-based auctions and opportunities to bid for 30 days or less fuel stored on site, overall cost increases may be minimized because the existing capacity for on-site fuel storage may be substantial, hence auction prices may be lower than many would anticipate. In any event, FERC could propose variants of the DOE proposed rule that would significantly increase system resilience, and reduce the probability of long-term outage and resulting financial losses. Overall, the long-term financial impact on consumers would be strongly positive. New marginal investments in generating capacity may be able to reduce costs per unit of capacity because new systems can be rendered more resilient at substantially reduced costs. By promptly preserving generation plants with significant fuel stored on-site—most especially nuclear power plants—the cost of resilience would be lower than if remedial resilience steps are taken after a blackout demonstrates regulatory deficiencies.

5. The Commission may take notice of relevant public information, including information in other Commission proceedings. If a commenter views information in another Commission proceeding as relevant to the proposed rule, please identify that information and explain how it is relevant to the proposed rule. Such information may include a filing previously submitted by the commenter.

Please refer to our previous filing on FERC Docket AD17-8-000 (June 19, 2017 for presentation June 22, 2017) for more analysis on the impact of Organized Markets in regard to on-site fuel storage and dual-fuel capability.

Moreover, it is our understanding that various reports of the EMP Commission and Staff Reports to the EMP Commission, now in the pre-release review process, may be pertinent to FERC's determination as to whether an energy "emergency" now exists and whether various resilient pricing initiatives deserve the support of FERC Commissioners.

Conclusion

Two decades of experience with competitive electricity markets in the U.S. have shown that the current constructs do not adequately value grid resilience in price formation. As a result, we see dramatic decline in the proportion of generation plants with energy stored on-site and also decline in dual-fuel capability. Explicit compensation for energy inventory at generation plants will increase resilience and reduce the probability of large economic losses and widespread human casualties from long-term outage. The proposed DOE rule is a step in the right direction, but alternatively setting goals for the total energy inventory stored at generator sites in each RTO/ISO could increase operational flexibility and add to the types of generator technologies that could participate. Flexible quantities of energy inventory stored on-site at generators could be implemented by market mechanisms.

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CERTIFICATE OF SERVICE

I hereby certify that I caused a copy of the foregoing document to be served electronically upon each person designated on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission.

Dated at this 23rd day of October 2017.

/s/ William R. Harris

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