FEDERAL ENERGY REGULATORY COMMISSION

Final Report
Review of Federal Energy Regulatory Commission Agency Actions Pursuant to Executive Order 13783, Promoting Energy Independence and Economic Growth

I. Executive Summary

On March 28, 2017, the President signed Executive Order 13783, titled Promoting Energy Independence and Economic Growth (Executive Order).[1] Pursuant to section 2(c) of the Executive Order, on May 12, 2017, the Federal Energy Regulatory Commission (FERC, or the Commission) submitted to the Office of Management and Budget (OMB) its plan (Plan) for reviewing its existing regulations, orders, guidance documents, policies, and any other similar agency action (agency actions) that potentially burden the development or use of domestically produced energy resources. On July 26, 2017, pursuant to section 2(d) of the Executive Order, the head of the Commission submitted a draft final report detailing the review undertaken and the results of the review. Given the Commission's status as an independent regulatory agency, this final report is being submitted on a voluntary basis.[2]

Of the agency actions reviewed, this final report identifies nine agency actions that potentially materially burden the development or use of domestic energy resources as contemplated by the Executive Order and clarified by OMB's May 8, 2017 Guidance Memo.[3] In addition, these identified agency actions may be addressed in conjunction with the Commission's ongoing efforts pursuant to Executive Order 13777.

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[1] Executive Order 13783, *Promoting Energy Independence and Economic Growth*, 82 Fed. Reg. 16093 (Mar. 28, 2017).

[2] The Commission is a multi-member, independent regulatory agency that must follow applicable federal laws to change its rules, regulations and orders. Because the Commission must ultimately decide what action, if any, to take in response to the Executive Order, this report is a Commission staff analysis of the issues identified for review in the Executive Order and does not specifically recommend actions nor indicate the timing of any potential action.

[3] Memo from Dominic J. Mancini, Acting Administrator, Office of Information and Regulatory Affairs to Regulatory Reform Officers and Regulatory Policy Officers at Executive Departments and Agencies regarding Guidance for Section 2 of Executive Order 13783, titled "Promoting Energy Independence and Economic Growth."

II. Background

Section 2 of the Executive Order requires the heads of federal agencies to immediately "review all existing regulations, orders, guidance documents, policies, and any other similar agency actions (collectively, agency actions) that potentially burden the development or use of domestically produced energy resources, with particular attention to oil, natural gas, coal, and nuclear energy resources. Such review shall not include agency actions that are mandated by law, necessary for the public interest, and consistent with the policy set forth in section 1 of this order."

On May 8, 2017, OMB issued a Guidance Memo providing additional information regarding compliance with the Executive Order, in particular section 2. The Guidance Memo noted that the Executive Order does not apply to independent agencies as defined in 44 U.S.C. 3502(5), but encouraged independent regulatory agencies, especially those that directly regulate the development or use of domestically produced energy resources, to provide the plan and report that are called for in section 2 of the Executive Order. The Guidance Memo further encourages agencies to coordinate their compliance with Section 2 of Executive Order 13783 with their compliance with Executive Order 13777, which directs agencies to establish Regulatory Reform Task Forces to evaluate existing regulations generally and make recommendations to the agency head regarding their repeal, replacement and modification, consistent with applicable law.

In the Plan, the Commission explained that it intended to review agency actions it has taken pursuant to legislative authority under: (1) the Natural Gas Act (NGA), 15 U.S.C. §§ 717, et seq.; (2) the Federal Power Act (FPA), 16 U.S.C. §§ 791a, et seq.; (3) the Interstate Commerce Act, 49 App. U.S.C. § 1 et seq.; (4) the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. §§ 2601 et seq., and (5) other statutes for which the Commission's actions on LNG, natural gas pipeline, and hydropower projects often require compliance, such as the National Environmental Policy Act, the Endangered Species Act, the Coastal Zone Management Act, and the Clean Water Act.

III. Commission Review of Agency Actions Pursuant to Section 2

A. Scope of Review

Domestic Energy Sources: Section 2 of the Executive Order states that the review should place particular attention on oil, natural gas, coal, and nuclear energy resources. In addition, section 1 of the Executive Order and the Guidance Memo list renewable sources, including flowing water, as domestic energy sources. Therefore, this final report considers agency actions that potentially affect not only oil, natural gas, coal, and nuclear energy resources, but also hydropower and other renewable generation resources.

Potentially Material Burdens: Section 2(b) of the Executive Order states that "burden" means "to unnecessarily obstruct, delay, curtail, or otherwise impose significant costs on the siting, permitting, production, utilization, transmission, or delivery of energy resources." Based on the Executive Order's definition of "burden," as informed by the Guidance Memo which highlights agency actions that "materially" affect domestic energy production, this final report considers an agency action "material" if it could: (1) directly affect the development or use of domestic energy resources; or (2) have a primary indirect effect on the development or use of domestic energy resources.[4] Given the Commission's limited jurisdiction, none of the Commission's agency actions would materially affect the design and/or location of drilling or mining of energy production resources.

Agency Actions: This final report considers the following types of binding Commission agency actions in existence as of March 28, 2017 (i.e., the date of issuance of Executive Order 13783): codified regulations published by the Commission (i.e., 18 C.F.R.); final rules; public policy statements and guidance documents; and case-specific orders and opinions that establish policies that are broadly applied and not otherwise codified by the Commission.[5]

B. Methodology

This final report identifies and classifies the potentially relevant agency actions based on: (1) the type of action undertaken; (2) the energy source potentially affected by that action; and (3) whether the potential effects of the action are direct or indirect.

This final report focuses on agency actions in four jurisdictional areas: (1) hydropower licensing; (2) LNG facility, and natural gas pipeline and storage facility siting; (3) centralized electric capacity market policies in PJM Interconnection, L.L.C. (PJM), ISO New England, Inc. (ISO-NE), and New York Independent System Operator, Inc. (NYISO); and (4) electric generator interconnection policies.

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[4] The Guidance Memo indicates that agencies should review actions that both directly and indirectly affect domestic energy sources. This final report uses the term "primary indirect effect" to define the scope of indirect effects that will be considered for review. A primary indirect effect is an effect that is only one step removed from a direct effect. In other words, a primary indirect effect occurs when an agency action affects a factor that, in turn, affects a domestic energy source.

[5] This report does not consider the issue of grants to third parties to perform agency actions because the Commission does not issue such grants. Commission staff's analysis included consideration of information collections, including those subject to the Paperwork Reduction Act, to the extent that such collections are within the scope of the agency actions reviewed under the Executive Order.

Commission actions in these four jurisdictional areas have the greatest potential to materially burden domestic energy resources as contemplated under the Executive Order. In particular, the Commission's hydropower licensing program has the potential to directly affect the design, location, and development of hydropower resources. In addition, the Commission's jurisdiction over the siting of LNG terminals and natural gas pipelines may affect the delivery to market of natural gas, and have a primary indirect effect on the use of that domestically produced energy resource.

Agency actions related to electric capacity market policies and generator interconnection policies may have a primary indirect effect on the development, retention, or retirement of domestic energy resources. As the Commission has recently recognized in its ongoing efforts concerning the interplay of wholesale electric markets and state policy, the centralized electric capacity markets in PJM, ISO-NE, and NYISO are intended to ensure long-term resource adequacy by sending accurate price signals for investment in electric capacity resources, when and where needed. By signaling the value of capacity, including the potential need for new generation resources, these markets serve a function in those regions that would otherwise typically be performed through integrated resource planning, often before a state public service commission. As a result, Commission actions related to electric capacity market policies could have a primary indirect effect on the development and use of generation resources.

Finally, agency actions involving generator interconnection policies could have a primary indirect effect on the development of domestic energy resources. For example, a wind or solar generator at utility scale typically must interconnect to the transmission grid in order to deliver the electricity produced by those domestic energy resources to the wholesale purchaser. If Commission policies or actions lead to a delay in interconnection or otherwise affect the generator's ability to interconnect, then the project developer may not develop that energy resource, which would impact the development or use of domestic energy resources.

This final report does not review agency actions involving oil and natural gas pipeline rates; electric energy and ancillary service rates and market policies;[6] electric

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[6] Commission actions on energy and ancillary service market rules are less directly related to the development and use of domestic energy resources than Commission actions on centralized capacity market rules. While energy and ancillary service markets have an effect on the economic viability and day-to-day use of generation resources, the market rules established by the Commission are intended to ensure recovery of variable costs (e.g., fuel costs) for marginal units, rather than to be the primary source of fixed cost recovery for new generation resources. That is, in regions that do not have capacity markets, there is an additional mechanism to address fixed cost recovery typically administered by the relevant state regulatory commission, in the case of investor-owned

transmission rates, including return on equity issues; demand response resources; mergers; enforcement; reliability; backstop transmission siting authority; and the Public Utilities Regulatory Policies Act. Commission action in these areas may indirectly impact the design, location, development, or use of domestic energy resources, but would not have a primary indirect effect, as discussed above.

Pursuant to the Guidance Memo's recommendation, this effort with respect to Executive Order 13783, to the extent appropriate, was coordinated with the Commission's Regulatory Reform Task Force created pursuant to Executive Order 13777.[7]

This final report discusses those agency actions that rose to the level of a potential material burden as contemplated by the Executive Order and clarified by the Guidance Memo. For hydropower licensing and the LNG and natural gas transportation facilities siting programs, the Executive Order review process revealed potentially burdensome agency actions related to regulations promulgated by the Commission. For electric capacity markets and generator interconnection, the Executive Order review process revealed potentially burdensome agency actions related to Commission rulemaking orders and case-specific orders, which typically did not result in the promulgation of regulations. This final report identifies steps the Commission may consider, to the extent permitted by law, to alleviate or eliminate the aspects of the agency actions that may burden the development or use of domestically produced energy resources.

C. Discussion

1. Hydropower Licensing

Under Part I of the FPA, the Commission has the exclusive authority to issue licenses, small capacity exemptions (up to 10 megawatts (MW)), and conduit exemptions for non-federal hydropower projects. The Commission currently regulates over 1,600 licensed or exempted hydroelectric projects, representing about 56,000 MW of authorized installed capacity, which is more than half of all developed hydropower in the United States.

The Commission is responsible for coordinating and managing the processing of hydropower project license and exemption applications, as well as applications for preliminary permits (under which permittees study proposed projects). This includes determining the effects of constructing, operating, and maintaining hydropower projects on environmental resources, and the need for the project's power. Pursuant to the FPA, issues considered during the review of license applications include power production;

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public utilities, or the management of public power utilities.

[7] As with Executive Order 13783, independent regulatory agencies like the Commission are not subject to Executive Order 13777, but are encouraged to comply.

fish, wildlife, recreation, and other environmental issues; flood control; irrigation; and other water uses. Various statutory requirements also give other agencies a significant role in project development, and several state and federal agencies have mandatory authorities that limit the Commission's control of the cost and time required for licensing.

Following the issuance of a license or exemption, the Commission oversees compliance with the terms and conditions of the license/exemption for the duration of the license. This includes processing the filing of plans, reports, and license amendments. Additionally, the Commission must determine if it has jurisdiction over proposed or unlicensed operating projects; determine and assess headwater benefit charges; approve transfers of licensed projects; resolve complaints alleging noncompliance with license and exemption conditions; and act on applications for license surrenders.

The Commission also is responsible for ensuring that the water-retaining features of hydropower projects are designed, constructed, operated, and maintained using current engineering standards and federal guidelines for dam safety. Commission staff inspects projects to investigate potential dam safety problems and, every five years, a Commission-approved independent consulting engineer must inspect and evaluate projects with dams higher than 32.8 feet or with a total storage capacity of more than 2,000 acre-feet. The Commission also requires licensees to prepare emergency action plans and conducts training sessions on how to develop and test these plans.

The vast majority of agency actions relating to the Commission's hydropower program do not present a material burden to hydropower resources. Specifically, most agency actions: (1) are necessary to administer the Commission's hydropower program and process hydropower license applications in an orderly manner; and/or (2) do not negatively affect the development of hydropower resources. As outlined below, however, this final report identifies three areas where potential material burdens may exist: licensing processes; exemption processes; and determinations on deficient applications.

a. Licensing Processes

i. ILP Default Regulation

The Commission's regulations include three hydropower licensing processes for applicants: the Integrated Licensing Process (ILP), the Traditional Licensing Process (TLP), and the Alternative Licensing Process (ALP). The Commission's regulations assign the ILP as the default process for all license requests, and an applicant must specifically request and justify the use of either the TLP or ALP. Assigning the ILP as the default process could be materially burdensome due to: (1) the time and costs associated with obtaining the Commission's approval to use the TLP or ALP; and (2) in the event the Commission denies the request to use the TLP/ALP, there may be additional time and costs associated with the ILP, due to the structured nature of the process. The level of burden caused by the ILP default regulation is largely project-specific, and may be negligible/non-existent for complex proceedings that could benefit from a more structured process such as the ILP. However, any material burden could be alleviated by making the ILP optional, and removing the requirement to seek Commission authorization to use the TLP and ALP (see 18 C.F.R. § 4.30, 5.1, 5.3, 5.8, 16.1).

ii. Pre-Filing Application Requirement

In the final stages of the Commission's pre-filing process for hydropower projects, the Commission's regulations require a potential applicant to submit a draft license application or preliminary licensing proposal before submitting a final license application (18 C.F.R. § 4.38(c)(4) and 5.16, respectively). The Commission's regulations include minimum filing requirements for these documents (e.g., study results, analyses, and environmental measures), and a stakeholder review process. The requirement to file the draft application and preliminary licensing proposal may be materially burdensome in terms of the cost and delay associated with the preparation of the documents and the stakeholder review process. To eliminate material burdens, the Commission could consider revising its regulations to make this aspect of the pre-filing process optional for license applicants.

iii. Pre-Filing Schedule

The ILP contains comment and filing deadlines throughout the pre- and post-filing application process to ensure a structured approach to hydropower licensing. The ILP, however, may be materially burdensome in terms of the schedule established for the pre-filing process (3 – 3.5 years total). To alleviate this burden, the Commission could consider certain comment and filing deadline reductions to allow for an overall time savings of three months: (1) reduce the time that an applicant has to file a proposed study plan, and the Commission has to issue a second scoping document, from 45 days to 30 days after receiving comments (18 C.F.R. § 5.10 and 5.11); (2) reduce the time for entities to file comments on the proposed study plan, from 90 days to 60 days (18 C.F.R. § 5.12); (3) reduce the time an applicant has to file a revised study plan, from 30 days to 15 days (18 C.F.R. § 5.13); and (4) reduce the time for filing comments on an applicant's preliminary licensing proposal, from 90 days to 60 days (18 C.F.R. § 5.16).

iv. License Term Policy

Section 6 of the FPA provides that hydropower licenses shall be issued for a term not to exceed 50 years. There is no minimum license term for original licenses (16 U.S.C. § 799). Section 15(e) of the FPA provides that any new license for an existing project (i.e., relicense) shall be for a term that the Commission determines to be in the public interest, but not less than 30 years or more than 50 years (16 U.S.C. § 808(e)). Current

Commission policy is to set a 30-year license term where there is little or no authorized redevelopment, new construction, or environmental mitigation and enhancement; a 40-year license term for a license involving a moderate amount of these activities; and a 50-year license term where there is an extensive amount of such activity.[8] On November 17, 2016, the Commission issued a notice of inquiry in FERC Docket No. RM17-4-000 inviting comments on what changes, if any, should be made to the license term policy. The license terms provide operational certainty and govern the frequency of the license renewal process, which influences the overall cost of development. In turn, shorter license terms could burden development by increasing the cost of development. The Commission currently is considering comments on the license term policy, which it could use to further evaluate the need for any future changes to the license term policy.

v. Minimum Filing Requirements

The Commission's regulations contain minimum filing requirements depending on the size of a project, and whether construction or modification of a dam is needed for project operation. Part 4 of the Commission's regulations includes three subparts corresponding to these factors: (1) Subpart E – Application for License for Major Unconstructed Project and Major Modified Project (18 C.F.R. § 4.40); (2) Subpart F - Application for License for Major Project – Existing Dam (18 C.F.R. § 4.50); and (3) Subpart G - Application for License for Minor Water Power Projects and Major Water Power Projects 5 MW or Less (18 C.F.R. § 4.60). Subparts E and F apply to projects greater than 5 MW, and include more onerous filing requirements than Subpart G, which applies to projects less than or equal to 5 MW. The 5 MW threshold is based on section 405 of PURPA, which mandated a simplified and expeditious licensing procedure for small hydroelectric power projects with an installed capacity of 5 MW or less (*see* 46 FR 55,944 at 55,947 (1981); 16 U.S.C. § 2705). The Hydropower Regulatory Efficiency Act of 2013 has since amended PURPA by increasing the size of a small hydroelectric power project from 5 to 10 MW. Therefore, the 5 MW threshold in 18 C.F.R. § 4.40, 4.50, and 4.60 is materially burdensome to projects between 5 and 10 MW, in terms of the cost and time associated with the more onerous filing requirements of Subparts E and F. To eliminate the material burden, the Commission could consider revising its regulations to increase the threshold from 5 MW.

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[8] *See City of Danville, Virginia*, 58 FERC ¶ 61,318 (1992); and *Consumers Power Co.*, 68 FERC ¶ 61,077, (1994).

b. Exemption Processes

i. Increased Capacity Requirement

To qualify for a license exemption under section 405 of PURPA, an applicant must propose to install/increase the total capacity of a project to not more than 10 MW (18 C.F.R. § 4.30(b)(31), 4.31(c), and 4.103(a)). The regulatory requirement to add new capacity at the project is not specifically required by section 405 of PURPA, and it materially burdens existing licensees that would otherwise be eligible to seek an exemption at the end of the existing license term. To eliminate this burden, the Commission could consider revising the regulations to remove the requirement to install or increase the capacity of the facility to qualify for an exemption.

ii. Small Hydropower Conversion Restrictions

In the event that the Commission rejects an exemption application, the Commission's regulations do not explicitly provide an applicant with the ability to convert a small hydropower exemption application to a license application (18 C.F.R. § 4.105). The Commission's Handbook for Hydroelectric Project Licensing and 5 MW Exemptions from Licensing, issued April 2004, explicitly states at section 6.3.2:

> If the exemption application is dismissed, the process is terminated. There is no opportunity to convert the exemption application to an application for license.[9]

In comparison, the Commission has established a process for converting a small conduit exemption application to a license application (18 C.F.R. § 4.93). The process for small conduits allows the applicant to submit additional information necessary to conform the conduit exemption application to the relevant regulations for a license application, and then be accepted for filing as of the date the exemption application was accepted for filing. The inability of an applicant of a small hydropower exemption to convert its application to a license application is materially burdensome because the applicant must initiate an entirely new license process after its exemption is rejected, thereby causing delay to the development of the resource. To eliminate this burden, the Commission could consider amending its regulations to explicitly provide the small hydropower exemption applicant with the ability to convert its exemption application to a license application if the exemption application is rejected.

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[9] *See www.ferc.gov/industries/hydropower/gen-info/handbooks/licensing_handbook.pdf.*

c. Prohibition on Refiling Subsequent License Applications

Pursuant to the authority provided in section 10(i) of the FPA (16 U.S.C. § 803), the Commission routinely waives certain sections of Part I of the FPA when it issues a minor license. As relevant, the Commission routinely waives section 15 of the FPA, which governs the Commission's procedures for issuing a new license to an existing licensee (i.e., a relicense) (16 U.S.C. § and 808). Yet, the Commission's regulations require the licensee to file an application for relicense at least 24 months before the expiration of the existing license (18 C.F.R. § 16.20(c)). Moreover, if the Commission rejects the application, it cannot be refiled (18 C.F.R. § 16.9(b)(4)). Rejecting a relicense application, and not providing the applicant with the opportunity to refile, is materially burdensome to the use of hydropower resources. To eliminate this burden, the Commission could consider revising its regulations at 18 C.F.R. § 16.20 to provide the applicant with the option of resubmitting the application if the deficiencies are corrected.

2. LNG Facility and Natural Gas Pipeline and Storage Facility Siting

Under section 7 of the NGA, 15 U.S.C. § 717f, the Commission authorizes the construction, operation, or abandonment of interstate natural gas pipeline and storage projects, as well as certain types of LNG facilities (e.g., LNG plants engaged in the storage of interstate natural gas volumes). Similarly, under section 3 of the NGA, 15 U.S.C. § 717b(e)(1), the Commission authorizes the siting, construction and operation of LNG terminals through which the commodity passes for export or import. As part of these responsibilities, the Commission conducts both a non-environmental and an environmental review of the proposed facilities. The non-environmental review focuses on the engineering design, rate, and tariff considerations. The Commission carries out the environmental review with the cooperation of numerous federal, state, and local agencies, and with the input of other interested parties. Under the NGA, the Commission also is the lead federal agency for coordinating all applicable federal authorizations (e.g., required permits under the Clean Water Act, Clean Air Act, and Coastal Zone Management Act, among others) and preparing environmental analyses required under the National Environmental Policy Act (NEPA) for all interstate natural gas infrastructure and LNG import/export proposals.

There are several distinct phases to the review process for interstate natural gas and LNG facilities under the Commission's jurisdiction: pre-filing review (if applicable); application review; and post-authorization compliance. During the pre-filing review, Commission staff begins work on the environmental review and engages with stakeholders with the goal of resolving issues before the filing of an application. Throughout the pre-filing process, Commission staff meets with stakeholders, visits the project site, and confers with federal, state, and local agencies.

Once a project sponsor files an application with the Commission under NGA section 3 for LNG import/export terminals or under NGA section 7 for interstate pipeline and storage facilities, Commission staff analyzes both environmental and non-environmental aspects for a proposed project, including for LNG terminals safety and engineering. An Environmental Assessment or Environmental Impact Statement typically is issued for public comment, and ultimately, the Commission will issue an order on an application after considering both environmental and non-environmental issues.

During the post-authorization compliance period, Commission staff monitors the project sponsor's compliance with the conditions directed by the Commission. Ultimately, Commission approval is required before the facility can begin operation and provide service.

Pursuant to Executive Order 13783, the review encompassed the Commission's regulations, guidance documents, and policies related to the certification of interstate natural gas transportation facilities, authorization of LNG import and export facilities, authorization of certain transportation by interstate and intrastate pipelines, and environmental review under NEPA.

The majority of agency actions relating to the siting and construction of interstate natural gas transportation and LNG facilities do not materially burden the transportation or delivery of domestically produced natural gas. Specifically, most of the Commission's actions: (1) are necessary for the Commission to review and process NGA section 3 and 7 project applications; and/or (2) do not negatively affect the siting or construction of natural gas pipeline and storage facilities or LNG import/export facilities in a manner that has a direct or primary indirect effect on the development or use of domestic energy production.

However, the Commission's regulations require a prospective applicant for authorization under section 3 of the NGA to site and construct LNG terminals and related jurisdictional natural gas facilities to engage in the Commission's pre-filing process. (18 C.F.R. § 157.21(a)). The Commission's pre-filing regulations require applicants to use the pre-filing process for a minimum of 180 days before the filing of an application for any project that is required to engage in pre-filing. (18 C.F.R. § 157.21(a)(2)(1) and 153.6(c)). While, in general, the pre-filing process is designed to expedite the processing of applications, the mandatory imposition of the pre-filing process on LNG terminals and related pipeline projects for at least 180 days before an application can be filed may be materially burdensome for some projects in terms of the potential delay and costs associated with the process. Although the 180 day pre-filing process is required by statute for LNG terminals, 15 U.S.C. § 717b-1(a), the statute did not mandate that the Commission also require "related jurisdictional natural gas facilities" to engage in pre-filing. However, related jurisdictional natural gas pipeline facilities need to be evaluated concurrent with a proposed LNG terminal to avoid segmentation under the National Environmental Policy Act. Further, the pre-filing process allows stakeholders to become involved in the overall Project at an early stage, and applicants can benefit from stakeholder's early identification and resolution of issues that may overlap with the LNG terminal. Without using the pre-filing process for related jurisdictional natural gas facilities, delays could occur during the application review, when issues are first identified and need resolution. Thus, although this regulation may result in delays or additional costs to the applicant early on in a project's development, its overall result is a more timely application review by considering all issues regarding a project concurrently. As such, there is no need for the Commission to consider any revision to this regulation.

3. Centralized Electric Capacity Market Policies

Three of the Regional Transmission Operator/Independent System Operator (RTO/ISO) markets in the eastern U.S. have adopted centralized capacity markets to help address resource adequacy concerns.[10] In particular, PJM, ISO-NE, and NYISO have implemented centralized capacity markets that were designed, in part, to ensure long-term resource adequacy by sending accurate price signals for investment in capacity resources, when and where needed.[11] As a result, agency actions related to capacity market policies could have a primary indirect effect on the development and use of generation resources, including renewables, natural gas, and nuclear facilities.[12]

The centralized capacity markets require load-serving entities to secure, either through self-supply[13] or participation in the capacity auction, sufficient resources to meet their

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[10] The Commission has defined resource adequacy as "the availability of an adequate supply of generation or demand responsive resources to support safe and reliable operation of the grid." *Cal. Indep. Sys. Operator Corp.*, 122 FERC ¶ 61,017, at P 3 (2008).

[11] "Capacity is not actual electricity. It is a commitment to produce electricity or forgo consumption of electricity when required." *Advanced Energy Mgmt. All. v. FERC*, No. 16-1234, 2017 WL 2636455, at *1 (D.C. Cir. Jun. 20, 2017); *see Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 482 (D.C. Cir. 2009) (explaining that capacity "amounts to a kind of call option that electricity transmitters purchase from parties – generally, generators – who can either produce more or consumer less when required").

[12] It is important to note that the Commission has not required RTOs/ISOs to implement centralized capacity markets; rather, the determination to include such markets has been a voluntary decision by the stakeholders in each particular RTO/ISO. However, once an RTO/ISO decides to implement such a capacity market, the Commission must ensure that the tariff provisions establishing the capacity market rules are just and reasonable and not unduly discriminatory or preferential.

[13] While the specific rules vary by RTO/ISO, load-serving entities can own or construct resources or contract bilaterally for capacity from resources owned by other entities.

capacity obligation at a future time. All three centralized capacity markets allow participation by any resource that is technically qualified to provide the capacity product being procured and each market generally models locational constraints. Each conducts a capacity auction where eligible offers to sell capacity are compared to the demand for capacity resources, which is established through an administratively-determined demand curve. Generally speaking, the market clears based on the intersection between the supply and demand curves. All cleared resources receive the market clearing price for capacity regardless of resource type.

The Commission has issued multiple agency actions (i.e., Commission orders addressing the capacity market designs of the relevant organized markets) that govern the rules and design of the centralized capacity markets. Agency actions related to electric capacity markets were reviewed to determine if they impose a material burden on the development and use of domestic energy resources. In general, agency actions regarding centralized electricity capacity market design do not impose a material burden on the development and use of domestic energy resources because they generally seek to ensure adequate resources, and thereby facilitate the development of domestic energy resources, rather than create material burdens to the development and use of these resources. However, this final report discusses Commission actions regarding one aspect of centralized electricity capacity markets, buyer-side market power mitigation rules, due to the potentially material burdens Commission actions may have on the development of domestic energy resources.

All three eastern RTOs/ISOs use some form of a minimum offer price rule (MOPR) as approved by Commission order. MOPRs as currently designed establish offer floors for certain new resources to protect against subsidized new entry that has the potential to artificially suppress capacity market prices. New resources that trigger this rule are required to submit offers into the capacity market auction at or above the floor. If the resource's mitigated offer price is too high to clear in the market, then the resource would not receive a capacity obligation and the associated market payments. Depending on the terms of any out-of-market contracts, the resource also may not be eligible to receive out-of-market payments if it does not clear in the capacity market auction. Without such compensation, the developer may conclude it is not economic to develop the resource. In this way, Commission actions on the MOPR arguably impose a burden on certain new resources.

However, Commission actions on the MOPR do not rise to the level of a material burden, as the term is defined in the Executive Order and Guidance Memo. While application of the MOPR to a generator's bid may conceivably result in the developer deciding not to develop its generation resource, an individual generation developer's decision not to develop as a result of being subject to a MOPR would not in and of itself materially affect the use or development of oil, natural gas, coal, nuclear energy, or other domestic energy resources in the U.S. Therefore, Commission actions on MOPRs do not negatively affect the development and use of domestic energy resources by the electricity sector, despite the potential burden on those individual resources that are mitigated. Furthermore, from the perspective of other resources in the market, the MOPR can help preserve the integrity of the market price signals and revenue streams, thereby facilitating development and retention of other resources that might use domestic energy resources.

4. Generator Interconnection Policies

Electric generators use domestic energy resources to produce electricity. Electric generators at utility scale must interconnect to the transmission system to deliver the electricity they produce to customers and receive benefits from the wholesale electric markets. The interconnection process is designed to ensure a new resource can safely and reliably deliver its output to end-users and to assign the costs to the party causing the costs of any system upgrades required to maintain safety and reliability. If a generator is not able to interconnect to the transmission system, or if it is too difficult or expensive to do so, the developer may decide not to pursue investment in the electric generation resource. Therefore, the ability of an electric generator to interconnect to a transmission system could affect the development or use of domestic energy resources.

The Commission has issued multiple agency actions that govern and facilitate the interconnection of electric generators to public utility transmission systems. They include:

Order No. 2003: In Order No. 2003, the Commission created standard large generator interconnection procedures and adopted a standard large generator interconnection agreement for the interconnection of electric generators larger than 20 MW, regardless of resource type.[14]

Order No. 2006: In Order No. 2006, the Commission created standard small generator interconnection procedures and a standard small generator interconnection agreement for the interconnection of electric generators no larger than 20 MW.[15]

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[14] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

[15] *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180, *order on reh'g*, Order No.

Order No. 661: In Order No. 661, the Commission required public utilities to add standard procedures and technical requirements for the interconnection of large wind generation resources to their standard large generator interconnection procedures and large generator interconnection agreements in their open access transmission tariffs.[16]

Order No. 827: In Order No. 827, the Commission revised the interconnection agreements for both large and small non-synchronous generators to eliminate exemptions for wind generators from providing reactive power.[17]

Order No. 828: In Order No. 828, the Commission modified the small generator interconnection agreement as set forth in Order Nos. 2006 and 792 to require newly interconnecting small generating facilities to ride through abnormal frequency and voltage events and not disconnect during such events.[18]

Order No. 792: In Order No. 792, the Commission revised the standard small generator interconnection procedures and standard small generator interconnection agreement for the interconnection of electric generators no larger than 20 MW.[19]

None of these orders materially burden the development or use of domestic energy resources. The Commission's generator interconnection orders establish an orderly, uniform process for all types of generators to interconnect to the grid safely and reliably, facilitating their development by providing them with the means to deliver the electricity they produce to the purchaser. As such, these requirements will not unnecessarily obstruct, delay, curtail or otherwise impose significant costs on the siting, permitting, production, utilization, transmission, or delivery of energy resources and therefore they will not materially burden the production or use of domestic energy resources.

2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006).

[16] *Interconnection for Wind Energy*, Order No. 661, FERC Stats. & Regs. ¶ 31,186, *order on reh'g*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005).

[17] *Reactive Power Requirements for Non-Synchronous Generators*, Order No. 827, FERC Stats. & Regs. ¶ 31,385, *order on reh'g*, 157 FERC ¶ 61,003 (2016).

[18] *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, Order No. 828, 156 FERC ¶ 61,062 (2016).

[19] *Small Generator Interconnection Agreements and Procedures*, Order No. 792, 145 FERC ¶ 61,159 (2013), *clarifying*, Order No. 792-A, 146 FERC ¶ 61,214 (2014).