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Energy Policy Update: Trump Administration and Congress Pursue Separate Paths on U.S. Energy Policy, but Share Objectives

By Donna J. Bobbish

Eight months into the Trump administration, the White House and Congress have taken separate paths on U.S. energy policy. The Senate is making another effort to pass bipartisan "tweaks" to aspects of energy policy, while President Trump has announced an "America-First" energy policy to be implemented through executive action. Nonetheless, both Congress and the White House appear to be focused on expediting required authorizations for energy infrastructure projects and facilitating U.S. energy exports, and their separate efforts could eventually be joined to form a unified energy policy.

Senate Bipartisan Energy Legislation

At the end of June, Senator Lisa Murkowski (R-AK), chairman of the Energy and Natural Resources Committee, and Maria Cantwell (D-WA), ranking member of that committee, introduced the "Energy and Natural Resources Act of 2017" (S. 1460). S. 1460 is the successor to the "Energy Policy Modernization Act," the omnibus bipartisan legislation that passed the Senate in 2016 but could not be reconciled with an energy bill passed by the House of Representatives. Like its predecessor Senate bill, S. 1460 would change certain aspects of current U.S. energy policy, including regulatory reforms to accelerate the approval process for energy projects.

LNG Exports

In circumstances, where the U.S. Department of Energy (DOE) must authorize exports of natural gas, including liquefied natural gas (LNG), under Section 3(a) of the Natural Gas Act (NGA), and where authorization also is required from the Federal Energy Regulatory Commission (FERC) or the Maritime Administration to site, construct, expand or operate LNG export facilities, S. 1460 would require DOE to issue its final decision the export application no later than 45 days after the conclusion of the environmental review required by the National Environmental Policy Act of 1968 (NEPA) to authorize the siting, construction, expansion or operation of the LNG export facilities.

The Senate bill also would amend Section 3 of the NGA to require an applicant seeking authorization to export LNG to report to DOE the names of the countries of destination to which the exported LNG is delivered, and further would require DOE to publish on its website the reported destination information.

Reflecting concerns expressed by some Democrats about the effect of increased exports of U.S.-produced LNG on U.S. gas supplies and prices, S. 1460 also requires DOE to submit to Congress a study of the state, regional and national implications of exporting LNG with respect to consumers and the economy, including analyses of the economic impact that exporting LNG will have in regions that currently import LNG, and job creation in the manufacturing sector.

Hydropower

S. 1460 would require FERC to consult with other federal and state agencies to study improvements to the hydropower licensing process. It would also amend Part I of the Federal Power Act (FPA) to require FERC to coordinate with other federal agencies to develop overall schedules for federal authorizations required for a hydroelectric project and would extend preliminary permit terms and start of construction dates for hydroelectric projects. In addition, the Senate bill includes a Sense of Congress that all federal authorizations required for a hydropower project or facility, including a hydroelectric license issued by FERC, should be issued within three years after the date FERC considers an application to be complete.

The Senate bill also would amend Section 4(e) of the FPA (which requires FERC to give "equal consideration" to developmental and non-developmental values in its licensing decisions) to include in its consideration "minimizing infringement on the useful exercise and employment of property rights held by nonlicensees."

Energy Storage

S. 1460 would require and appropriate funds for DOE to conduct a program of research, development and demonstration of electric grid energy storage, focusing on, among other things, "fundamental and applied research critical to widespread deployment of electricity storage."

The Senate bill also would require FERC to submit to the Senate Energy and Natural Resources Committee a report describing any barriers to the development and proper compensation of pumped storage hydropower projects and other energy storage facilities caused by transmission organization rules or FERC's regulations or policies under the FPA, and including FERC's recommendations for reducing those barriers.

Nuclear

S. 1460 would require the Nuclear Regulatory Commission (NRC) to submit within a year a plan to develop an efficient, risk-informed and technology-neutral framework for licensing advanced nuclear reactors, including options to expedite and streamline the licensing of advanced nuclear reactors. The plan must be submitted to the Committee on Energy and Commerce of the House of Representatives and the Committee on Environmental and Public Works of the Senate.

Executive Branch Actions

American Energy Dominance

On the same day that Sens. Murkowski and Cantwell introduced S. 1460, President Trump spoke at a DOE event announcing a "new American energy policy" that would "seek not only American energy independence . . . but American energy dominance." As part of this energy policy, Trump stated that the U.S. "will export American energy all over the world."

Trump announced "six brand-new initiatives to propel this new era of American energy dominance." However, several of the items he described are not governmental initiatives but, rather, actions taken by agencies under existing statutory authority, while other items are not "brand-new" but, rather, previously announced administration policies.

First, in order to "review and expand our nuclear energy sector," Trump announced "a complete review of U.S. nuclear energy policy" but did not provide any details concerning this review.

Second, he announced that the Treasury Department will "address barriers to the financing of highly efficient, overseas coal energy plants" that would use coal exported by the U.S. Presumably, the president was referring to the Treasury Department's rescinding the guidance on coal financing it issued in 2013 ending U.S. support for multilateral development bank (MDB) funding of new international coal projects except in narrowly defined circumstances. In mid-July, the Treasury Department issued Guidance stating that the Executive Director for the U.S. at each of the MDBs will apply three objectives in determining the U.S. position on projects and energy policy: promoting universal access to affordable, reliable, sustainable and clean energy; helping countries access and use fossil fuels more cleanly and efficiently; and helping to deploy renewable and other clean energy sources and support development of robust, efficient, competitive and integrated global markets for energy.

Third, the president announced the approval of a new petroleum pipeline to Mexico. This announcement referenced the June 28 authorization issued by the State Department in response to a 2014 application submitted by NuStar Logistics, L.P. to construct pipeline facilities at the U.S.-Mexico border for importing or exporting refined petroleum products (naphtha, liquefied petroleum gas, natural gas liquids, jet fuel, gasoline and diesel) between the U.S. and Mexico.[1] The State Department's Bureau of Energy Resources receives and processes applications for Presidential Permits for cross-border liquid pipelines under Executive Order 13337, which was signed by President George W. Bush in 2004.

Fourth, Trump announced that Sempra Energy signed an agreement to begin negotiations to sell natural gas to South Korea. This announcement appears to be related to the proposed Port Arthur Liquefaction Project under development by a subsidiary of Sempra Energy near the City of Port Arthur, Texas, that would liquefy U.S.-produced natural gas for export to foreign markets. Port Arthur LNG, LLC (Port Arthur LNG) has filed an application with FERC under Section 3(a) of the NGA for authorization to construct and operate the liquefaction facility and also has filed an application with DOE for authorization to export LNG from the facility to countries with which the U.S. does not have free trade agreements that require "national treatment" for trade in natural gas (Non-FTA countries).

Fifth, he announced that DOE approved two long-term applications to export natural gas from Lake Charles LNG terminal in Louisiana.[2] These approvals were issued in response to applications filed with DOE in August 2016, under Section 3 of the NGA, which give DOE authority to approve exports of U.S.-produced natural gas, including LNG. Since 2012, DOE has authorized 28 applications for large-scale, long-term exports of U.S.-produced LNG to non-FTA countries, totaling some 21.33 billion cubic feet per day of natural gas.

Sixth, Trump announced the creation of a new offshore oil and gas leasing program but did not provide details of that program. It is not clear whether he was referring to anything beyond the "America-First Offshore Energy Strategy" outlined in an Executive Order signed in late April.[3] Executive Order 13795 declares that the policy of the U.S. is "to encourage energy exploration and production including on the Outer Continental Shelf, in order to maintain the Nation's positon as a global energy leader and foster energy security and resilience for the benefit of the American people, while ensuring that any such activity is safe and environmentally responsible." To implement this policy, the Executive Order, among other things,

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[1] *Presidential Permit Authorizing NuStar Logistics, L.P. To Construct, Connect, Operate and Maintain Pipeline Facilities at the International Boundary Between the United States and Mexico* (Jun. 28, 2017).

[2] *Lake Charles LNG Export Company*, LLC, "Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas By Vessel From the Lake Charles Terminal in Lake Charles, Louisiana, To Free Trade Agreement and Non-Free Trade Agreement Nations," DOE/FE Order No. 4101 (Jun, 29, 2107), and *Lake Charles Exports, LLC*, "Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas By Vessel From The Lake Charles Terminal In Lake Charles, Louisiana, to Free Trade Agreement and Non-Free Trade Agreement Nations," DOE/FE Order No. 4011 (Jun. 29, 2017).

[3] Executive Order 13795, "Implementing an America-First Offshore Energy Strategy" (Apr. 28, 2017), 82 Fed. Reg. 20815 (May 3, 2017).

directs the Secretary of the Interior, in consultation with the Secretary of Defense, to give full consideration to revising the schedule of proposed oil and gas lease sales to include annual lease sales to the maximum extent permitted by law in each of the following Outer Continental Shelf Planning Areas: Western Gulf of Mexico, Central Gulf of Mexico, Chukchi Sea, Beaufort Sea, Cook Inlet, Mid-Atlantic and South Atlantic.

Executive Order on Environmental Review and Permitting Process for Infrastructure

In August, President Trump issued an Executive Order finding that "[i]nefficiencies in current infrastructure project decisions, including management of environmental reviews and permit decisions or authorizations have delayed infrastructure investments."[4] It concludes that "the Federal Government, as a whole, must change the way it processes environmental reviews and authorization decisions" with respect to infrastructure development. Among other things, Executive Order 13708 requires each major infrastructure project, including "energy production and generation, including from fossil, renewable, nuclear and hydro sources, electricity transmission and pipelines" to have a lead federal agency be responsible for navigating the project through the federal environmental review and authorization process. It also requires all federal authorization decisions for the construction of a major infrastructure project to be completed within 90 days of issuing an environmental Record of Decision by the lead federal agency, provided that the final environmental impact statement (EIS) prepared under NEPA includes an adequate level of detail to inform agency decisions under their specific statutory authority and requirements.

This Executive Order applies to FERC licensing of hydroelectric projects, certification of natural gas pipelines and authorization of LNG terminals, as well as to NRC licensing of nuclear facilities.

DOE Proposed Rule to Expedite Authorization of "Small-Scale" Natural Gas Exports

In late August, DOE issued a Notice of Proposed Rulemaking (NOPR) to revise its regulations, providing for expedited authorization of natural gas exports not to exceed 0.14 Bcf per day ("small-scale exports"), where such authorization does not require the preparation of an EIS or environmental assessment (EA) under NEPA.

In support of its NOPR, DOE cited the "emerging market" for small-scale natural gas exports to countries primarily in, but not limited to, the Caribbean, Central America and South America. According to DOE, many of these countries do not generate enough natural gas demand to support the economies of scale required to justify large volumes of LNG imports from large-scale LNG terminals via conventional LNG tankers. DOE determined that small-scale natural gas exports are consistent with the public interest under Section 3(a) of the NGA, finding that such exports will not interfere with the domestic need for natural gas, will not have a detectable impact on domestic natural gas prices and will not pose a risk to the security of domestic natural gas supplies.

Under DOE's proposed rule change, in order to qualify for expedited approval, an application under Section 3(a) of the NGA to export natural gas, including LNG, to Non-FTA countries must satisfy two criteria. First the applicant must propose to export natural gas in a volume up to and including 0.14 Bcf/d. Second, DOE's authorization of the export must qualify for a categorical exclusion; that is, it is a class of action identified by DOE for which preparation of an EA or EIS normally is not required under DOE's NEPA regulations. If the export application meets these two criteria, DOE will issue an order granting authorization on an expedited basis, without providing notice of the application or following other procedures typically required for non-FTA export applications under DOE's regulations. DOE did not indicate, however,

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[4] Executive Order 13807, "Establishing Discipline and Accountability in the Environmental Review and Permitting Process for Infrastructure Projects" (Aug. 15, 2017), 82 Fed. Reg. 40462 (Aug. 24, 2017).

which categorical exclusions from NEPA published in its regulations would apply to small-scale exports of natural gas, or whether it would have to establish new categorical exclusions for such projects.

The deadline for submitting comments on the NOPR is October 16, 2017.

DOE Report on Electricity Markets and Reliability

In late August, DOE staff delivered to the Secretary of Energy, at his request, a Report on Electricity Markets and Reliability (DOE Report).[5] The DOE Report identified several issues critical to "protecting the long-term reliability of the U.S. electricity grid," principally, the competitive challenges faced by baseload power plants (including most nuclear, coal and natural gas steam generators) from wind- and solar-powered generation, and by coal- and nuclear-powered generation from natural gas-fired generation. Among other things, DOE staff found that wholesale electricity markets were designed to "ensure reliability and minimize the short-term costs of wholesale electricity," and this, according to DOE staff, has resulted in low average wholesale energy prices, which represent a "critical juncture for many existing baseload generation resources." DOE staff further found that most of the benefits of specific power plants, including jobs, community economic development, lower emissions, local tax payments and energy security, are not reflected in prices received through wholesale electricity markets, resulting in a variety of state and private initiatives to either keep open or shut down established baseload generators and provide incentives for developing wind- and solar-powered generating projects. DOE staff also found that the increased use of natural gas in the electricity sector has resulted in sustained low wholesale market prices that reduce the profitability of "other generation resources important to the grid," presumably coal and nuclear power. The DOE Report cites panelists at a FERC technical conference held in May who argued that competition from wind- and solar-powered generating resources that benefit from State Renewable Portfolio Standards (RPS) and federal tax credits reduces revenues for "traditional" baseload power plants, presumably coal and nuclear, by lowering the wholesale prices they receive and displacing a portion of their output.

The DOE Report acknowledges President Trump's "energy dominance" policy and includes a list of policy recommendations to address the issues identified by DOE staff. Notably, these recommendations do not included proposed legislation.

The DOE Report recommends that FERC expedite its efforts with states, regional transmission organizations and independent system operators and other stakeholders to improve energy price formation in centrally organized wholesale electricity markets. DOE asserts that the record of various proceedings pending before FERC supports energy price formation reform. Specifically, DOE recommends that 'negative offers should be mitigated to the broadest extent possible" —presumably referencing negative offers in energy markets by renewable resources receiving federal tax credits—but does not describe how such negative offers should be mitigated.

The DOE Report also recommends that FERC examine and propose ways to value new and existing Essential Reliability Services (ERS), including frequency control, ramping and voltage support, by creating fuel-neutral markets and/or pricing mechanisms to compensate grid participants for services that are necessary for reliable electricity grid operations.

With respect to infrastructure development, the DOE Report recommends that DOE and related federal agencies accelerate and reduce costs for the licensing, relicensing and permitting of grid infrastructure such as nuclear, hydro, coal, advanced generation technologies and transmission. In particular, it recommends that DOE review regulatory burdens for siting and permitting for electricity generation and natural gas and electricity transmission infrastructure, and "take actions to

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[5] *Staff Report to the Secretary on Electricity Markets and Reliability*, U.S. Department of Energy (Aug. 2017).

accelerate the process and reduce costs." For example, DOE staff observes that interstate natural gas pipelines often can be built more quickly than electricity transmission lines because a FERC certificate under Section 7(c) of the NGA authorizing pipeline construction gives pipeline owners eminent domain power under Section 7(h) of the NGA, whereas developers of electricity transmission lines must depend on states to grant eminent domain rights.[6]

The DOE Report indicates that potential "actions" that DOE might take after its review could include encouraging FERC to reexamine its licensing and relicensing processes for hydroelectric projects—particularly for small projects and pumped storage projects—to minimize regulatory burdens, encouraging the NRC to ensure the safety of existing and new nuclear facilities without unnecessarily adding to the operating costs and economic uncertainty of nuclear energy, and to reexamine nuclear safety rules under a risk-based approach, and encouraging the Environmental Protection Agency to allow coal-fired power plants to improve efficiency and reliability without triggering new regulatory approvals and associated costs.

Finally, the DOE Report recommends that utilities, states, FERC and DOE support greater coordination between the electricity and natural gas industries to address reliability concerns, and recommends that DOE and FERC support "well-functioning commodity markets for natural gas" by processing more expeditiously LNG export and cross-border natural gas pipeline applications.

Following the issuance of the DOE Report, current FERC Chairman Neil Chatterjee, who was appointed by President Trump and was confirmed by the Senate in August, issued a statement calling the DOE Report "important" and indicating that FERC already is considering some of the actions recommended in the DOE Report, including examining ways to enhance wholesale electric capacity markets and improve price formation in those markets. Chatterjee's statement may presage a greater level of cooperation on energy policy between DOE, a cabinet-level agency, and FERC, an independent agency within the DOE organizational structure.

On September 14, Chairman Chatterjee testified before the House Subcommittee on Energy, Committee on Energy and Commerce. During a hearing on "Powering America: Defining Reliability in a Transforming Electricity Industry," he was asked by Rep. Kevin Cramer (R-ND), who was an informal energy advisor to the Trump presidential campaign, to elaborate "from a FERC perspective" on any strategies that FERC could deploy that would help adequately compensate base load generation. In response, Chatterjee said that, being from Kentucky, he appreciates the role that coal-fired generation plays in electricity markets. He also indicated that in terms of future strategies, while FERC is "fuel-neutral," it will evaluate "the attributes of fuel sources to see what values they provide" in terms of reliability and whether those values "can be compensated." This House hearing could lay the groundwork for future legislative proposals on wholesale energy market pricing.

[6] DOE Report at p. 37.

Export Controls and Additive Manufacturing for the Nuclear Industry: Improvements in Regulation, but Progress Still Required

By Chelsea Gunter

In March 2017, Siemens announced that it installed its first 3D printed component in a commercial nuclear power plant: a metallic impeller for the fire protection system of the Krško Nuclear Power Plant in Slovenia. The feat was unique in the commercial nuclear industry; since the original manufacturer of the impeller was no longer in business, a team of engineers from Siemens reverse engineered the component from the existing part. The impeller operates in constant rotation and requires exacting specifications.[7]

Additive manufacturing, or 3D printing, is the process of joining metals or other materials by successive layers in order to form a specific component, while traditional subtractive manufacturing produces a component by removing successive portions of a material. Siemens' metallic impeller is not the first instance of additive manufacturing being used in the nuclear industry. The technology is already in use at the U.K.'s Sellafield site, where it was used to manufacture metal lids for low-level waste containers, as well as in India, where components have been fabricated for reprocessing plants and fast breeder reactors.[8] The company running decommissioning at Sellafield has stated that 3D printing could save it millions of dollars in costs.[9] In the U.S., labs that produce components for the nuclear fuel cycle, such as Sandia and Oak Ridge, also use 3D manufacturing, often to rapidly and cheaply develop prototypes to test their compatibility. Also in the U.S., the Department of Energy, in light of the promise of this technology, granted GE Hitachi $2 million to study uses for additive manufacturing in advanced nuclear technology in 2016.[10]

For an industry in which component manufacturers may cease to have business opportunities during the 60-plus-year operating life of a reactor, the appeal and importance of additive manufacturing for replacement parts is real. Taking into account the growth of the nuclear industry internationally, and that the global nuclear market could reach $750 billion in the course of the next decade, the potential for additive manufacturing to satisfy part of that market, and for U.S. manufacturers

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[7] Sarah Saunders, *Siemens Completes First Successful Installation of 3D Printed Part in Nuclear Power Plant*, 3DPRINT.COM (Mar. 9, 2017), https://3dprint.com/167384/siemens-nuclear-power-plant-part/.

[8] Grant Christopher, *3D Printing: A Challenge to Nuclear Export Controls*, 1 STRATEGIC TRADE REV. 18 (2015).

[9] *Additive Manufacturing Goes Nuclear*, 3DPRINTWISE, https://www.3dprintwise.com/3d-printing-nuclear-industry/ (last visited Sept. 19, 2017).

[10] Bridget Butler Millsaps, *DOE Chooses GE Hitachi to Complete Massive Research Project Studying Use of 3D Printing in Nuclear Power Plants*, 3DPRINT.COM (Jun. 24, 2016), https://3dprint.com/139797/ge-hitachi-research-doe/.

to benefit from it, is high.[11] As an emerging technology, additive manufacturing represents an opportunity for the U.S. to become a global leader in fabricating additive manufacturing methods to cut costs and create efficiencies.[12]

There are potential drawbacks to additive manufacturing, however: namely its potential use in weapons proliferation. Additive manufacturing printers currently on the market are capable of manipulating maraging steel, for instance, which can be used to produce components in a uranium enrichment centrifuge.[13] Other items that it may be possible to print via additive manufacturing that are currently on the Nuclear Supplier's Group's list of controlled trigger and dual-use items, and governed by US domestic export controls, include carbon fibre rotors and filament winding machines.[14] While no 3D printer is capable of directly printing the special nuclear materials required for a nuclear weapon, as the technology improves its capacity to handle other materials may result in the expansion of this list.

Current U.S. export controls, despite recent attempts to tailor their scope to risk and keep pace with developments in the additive manufacturing industry, have been criticized for their lack of clarity, with some commentators noting that they may hamper domestic development of this industry.[15] Part of the difficulty of regulating additive manufacturing is inherent in the complexity of the government's system for regulating export of nuclear materials. Currently, four federal agencies regulate nuclear export controls: the Nuclear Regulatory Commission regulates export of commercial nuclear materials, the Department of Energy's National Nuclear Security Administration regulates export of commercial nuclear material not governed by the NRC, the Department of Commerce regulates dual-use items, and the Department of State regulates munitions items.[16] While the Department of Commerce added additive manufacturing equipment that may be used for the production of turbine components—specifically, directional solidification or single-crystal additive manufacturing equipment—to the Commerce Control List in May 2015,[17] it is not clear that this addition addresses all the proliferation concerns that 3D printers may raise,[18] nor does it appear that the other federal agencies also chose to address controls for 3D printing technology.

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[11] *Nuclear Energy 2016: Status and Outlook – Annual Briefing for the Financial Community*, NEI (Feb. 11, 2016), https://www.nei.org/CorporateSite/media/filefolder/Policy/Wall%20Street/WallStreetBriefing2016Slides.pdf?ext=.pdf.

[12] Matthew Kroenig and Tristan Volpe, *3-D Printing the Bomb? The Nuclear Nonproliferation Challenge*, 38 WASHINGTON Q. 7 (2015).

[13] Id.

[14] Christopher, *supra* note 2, at 18.

[15] U.S. GOV'T ACCOUNTABILITY OFF., GAO-15-124, NUCLEAR COMMERCE: ADDITIONAL ACTIONS NEEDED TO IMPROVES DOE'S EXPORT CONTROL PROCESS (2014); Thomas Graham, U.S. National Strategy for Additive Manufacturing: 2014 Capstone Project, CTR. GLOBAL SECURITY RES., https://cgsr.llnl.gov/content/assets/docs/AMCapstone_Final.pdf (last visited sept. 19, 2017).

[16] GAO, *supra* note 9.

[17] Wassenaar Arrangment 2014 Plenary Agreements Implementation and Country Policy Amendments, 80 Fed. Reg. 29432 (May 21, 2015).

[18] Kroenig and Volpe, *supra* note 6.

The National Nuclear Security Administration (NNSA) of the Department of Energy (DOE) has also been criticized for its recent changes to its nuclear export control regime, arguably missing an opportunity to clarify the role of 3D printers in that regime when it recently updated 10 C.F.R. Part 810, Assistance to Foreign Atomic Energy Activities, which came into effect March 25, 2015.[19] This regulation was modernized according to the agency in order to articulate which activities and technologies it covers and to provide an affirmative list of countries that can receive transfers of nuclear technology.[20] The regulation states that it covers:

> the transfer of technology that involves . . . [u]ranium isotope separation (uranium enrichment), plutonium isotope separation" and "nuclear reactor development, production or use of the components within or attached directly to the reactor vessel, the equipment that controls the level of power in the core, and the equipment or components that normally contain or come in direct contact with or control the primary coolant in the reactor core.[21]

As described above, it may be possible to use a 3D printer to produce components that can be used in isotope enrichment, suggesting that the purchase of any 3D printer able to manipulate maraging steel would be governed by Part 810. It may also be feasible for a 3D printer to produce components relevant to the reactor core. Indeed, the regulation has been faulted for its failure to define broad terms like "nuclear reactor," suggesting that 3D printers may very well be captured by this provision.[22] Yet, the updated regulation does not envision or provide guidance on either possibility, resulting in the likelihood that producers would need to request advice from DOE as the scope of the regulation is imprecise.

For companies that seek to 3D print nuclear components rather than sell the printers that may be used to do so, the regulation for export of such components also appears to be uncertain. In this regard, a GAO report of the proposed revisions to Part 810 noted that both the scope and application requirements of the law were unclear. This created uncertainty not only for the sale of such products overseas, but also for their marketing, which could require the transfer of design or other information potentially regulated by the NNSA as "sensitive nuclear technology."[23] While the revised Part 810 simplified some provisions—such as the definition of "publicly available information" and "publicly available technology," which are now excluded from the regulation, to delineate information that may be used in marketing activities—it does not clarify a number of remaining broad terms or offer an illustrative list of reactor components it covers.[24] Such criticism of Part 810 applies to manufactured exports of nuclear components regardless of whether they are 3D printed; however, it nonetheless represents a potential obstacle to the development of a domestic 3D printing capacity for the nuclear industry and the U.S. nuclear industry's access to the international market.

Industry leaders are moving forward nonetheless. Earlier in July, the 12th annual International Conference on Additive Manufacturing and 3D Printing was held in Nottingham, U.K. The event was attended by 280 representatives from over 18 countries and included speakers from the nuclear industry, such as Oak Ridge National Laboratories (ONRL). ORNL's representative at the conference noted that 3D manufacturing would benefit from analytical and visualization frameworks that could improve the certification process for products produced via additive manufacturing.[25] This observation highlights just how far industry has come in embracing additive manufacturing components and the extent to which critical thinking to generate smart regulation in this arena is urgently needed.

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[19] GAO, *supra* note 9.

[20] *10 CFR Part 810*, NISA, https://nnsa.energy.gov/aboutus/ourprograms/nonproliferation-0/npac/policy/10cfr810 (last visited Sept. 19, 2017).

[21] Scope, 10 C.F.R. Part 810.2(a)(2), 2(b)(4)-(5).

[22] GAO, *supra* note 9.

[23] Activities Requiring Specific Authorization, 10 C.F.R. §810.7.

[24] GAO, *supra* note 9.

[25] Prof Richard Hague, *Additive Takes Centre Stage*, Engineer (July 24, 2017, 2:02 PM), Theengineer.co.uk/additive-takes-centre-stage/.

The current moment represents an opportune time for government and industry to collaborate on the development of right-sized export controls and partnerships to encourage the development of additive manufacturing in the nuclear industry, both domestically and abroad.

Indonesia Regulations No. 48, 49 and 50: Back to Business?

By Bill McCormack and Jean-Louis Neves Mandelli

It is well known that the regulatory landscape for IPPs in Indonesia is constantly changing. However, this year Indonesian regulators have been particularly busy. As of the end of August, the Indonesian Ministry of Energy and Mineral Resources (MEMR) had issued 50 new regulations. Unfortunately, several of these have received a very negative response from investors. This was most notably the case for Regulations No. 10 and 12 of January 2017 and Regulation No. 42 of July 2017, which were seen as prejudicial to the bankability (or in the case of Regulation No. 12, economic viability) of future Indonesian IPPs. Please see our articles on each of these regulations for more information.[26] MEMR has since issued further regulations (namely Regulations No. 48, 49 and 50 of August 2017) revising or replacing Regulations No. 10, 12 and 42. In some cases, such as for Regulation 42, this was done less than one month after the original regulation came into force. This regulatory whirlwind has significantly slowed progress on new proposed Indonesian IPPs. Now that Regulations No. 48, 49 and 50 have entered into force, can business resume as before?

Changes to Risk Allocation – Regulations No. 10 and No. 49

Regulation No 10 codifies the risk allocation under Indonesian power purchase agreements (PPAs). New PPAs entered into with Indonesian state offtaker PT PLN Persero (PLN) must reflect the risk allocation set out in Regulation No. 10 regarding the matters it addresses. Although for the most part Regulation No. 10 reflected PLN PPA practice, there are two main areas where this was not the case:

Risk	Allocation before Regulation No. 10	Allocation under Regulation No. 10
Change in law	Borne by PLN. Generator benefits from: - Force majeure relief as well as deemed commissioning / capacity payments if change in law prevents performance of obligations / operation of the plant - Termination rights (with a buyout obligation by PLN) in case of long-term inability by generator to perform its obligations due to change in law	Borne by PLN and the generator. - New concept of "change in government policy" is introduced - Change in law and change in government policy are force majeure events which relieve both PLN and generator from their obligations - PLN is entitled to relief from its obligations in case a "change in government policy" causes a stoppage of the power plant.

[26] Reg 10: http://www.shearman.com/en/newsinsights/publications/2017/05/memr-regulation-10-of-2017-of-indonesia.
Reg 12: http://www.shearman.com/en/newsinsights/publications/2017/05/a-step-forward-or-a-step-back.
Reg 42: Article available upon request.

Risk	Allocation before Regulation No. 10	Allocation under Regulation No. 10
	- Tariff adjustments for increased costs due to change in law.	- Change in law which reduces costs entitle PLN to a reduction in the tariff. Change in law which increases costs entitle generator to an increase in tariff
Force majeure affecting the grid	Borne by PLN PLN is required to make deemed dispatch payments if it is not able to take power as a result of a force majeure event affecting the Indonesian grid.	Borne by generator? PLN is only required to make payments if the grid is affected by reasons other than force majeure.

(a) Change in Law Risk

With respect to change in law risk, Regulation No. 49 amends the allocation of "change in government policy" risk under PLN PPAs by deleting all references to it. This is certainly a welcome step, since it was very difficult to understand the difference between a "change in government policy" and a "change in law." However, Regulation No. 49 stops short of fully reversing the changes in risk allocation introduced by Regulation No. 10 with respect to change in law. In particular, "change in law" remains listed as a force majeure event for PLN. By definition this could mean that PLN would be relieved of its obligations under the PPA (potentially including payment) if these are affected by a change in law.

The right of PLN to require reductions in the tariff resulting from a change in law introduced by Regulation No. 10 has also not been amended by Regulation No. 49. However, this is less problematic. The tariff is designed to reflect the generator's costs. If these decrease, it seems fair that there should be a corresponding tariff reduction. There is precedent in other jurisdictions for a similar mechanism.

It is not yet clear how PLN's potential to benefit from "force majeure" relief due to change in law would affect future PPAs, as PLN is yet to issue a PPA under this new regulation. Departing from PLN's traditional risk allocation concerning change in law would be difficult to manage from a bankability perspective absent any other recourse against the Indonesian state for deemed commissioning/capacity payments and termination and buyout rights in case of changes in law that delay construction or prevent the operation of the plant.

(b) Force Majeure Affecting the Grid

Indonesian IPPs have historically been entitled to deemed capacity payments if PLN is unable to take power due to force majeure events affecting the grid, which is consistent with typical IPP practice. While it is unclear if Regulation No. 10 means that the generator would not be entitled to receive deemed capacity payments if force majeure affects the grid (some suggest that it would only mean that a waiting period would apply, as is currently the case), Regulation No. 49 does nothing to help address investor confusion as it does not address the allocation of grid risk.

The generator would still be entitled to an extension to the term of the PPA in case of natural disasters to recover the lost revenues, which would help mitigate the impact of force majeure affecting the grid. However, this would still represent a significant shift from the typical position PLN has taken in its PPAs.

Caps on Renewable Feed-In-Tariffs – Regulations No. 12 and No. 50

Regulation No. 12 imposed caps on tariffs for renewable projects based on the average cost of generating electricity in a local area in the previous year ("Generating BPP"). The caps were either: (a) the Generating BPP if Generating BPP for the area is less or equal to national average (i.e., Java, Sumatra and Bali); and (b) 85% of Generating BPP if Generating BPP for the area is above national average (i.e., other provinces).

The general response to Regulation No. 12 was that it would make renewable projects economically unviable, particularly in areas where the Generating BPP was lower than national average. This tended to be the case in areas that are heavily reliant on thermal—and especially coal-fired—power generation, which investors believed would not constitute an appropriate proxy for the cost of developing renewable energy projects. It is questionable whether it is appropriate to refer to the Generating BPP for areas where it is above the national average, given that renewable IPPs in these areas (which tend to be less developed) may need to invest in more transmission infrastructure to connect to the grid, resulting in higher costs and tariff.

Under Regulation No. 50, the cap on renewable energy tariffs in areas where the Generating BPP is less or equal to the national average has been removed, allowing for a bilateral tariff negotiation. This is certainly welcome news for renewable energy developers seeking to develop projects in Java, Sumatra and Bali.

However, the cap of 85% of the Generating BPP still applies to renewable tariffs for projects in areas where the Generating BPP is higher than national average. This could be problematic and hamper the development of renewable energy generation in less developed areas.

Share Transfer Restrictions – Regulations No. 10, 42 and 48

Regulation No. 10 required PLN consent for any transfer of shares in the generator company before the commercial operation date (COD), unless the transfer was to a 90% owned affiliate. It was expected that this would be obtained upfront through the Sponsors' Agreement typically entered into with PLN in the context of the PPA.

In July, Regulation No. 42 came into force, requiring MEMR to consent (in addition to PLN consent) to any transfer of shares in a generator company pre-COD. This raised significant bankability concerns as it would mean that any security given over the shares in a generator company would not be enforceable without MEMR consent. While the Sponsors' Agreement offered a platform to obtain PLN's upfront consent to transfers in case of share enforcements, there are no contractual arrangements with MEMR in the current Indonesian IPP structure that could be used for this purpose.

While many project financed IPPs in Indonesia include pledges over shares in offshore shareholders of the generator, in addition to pledges over shares in the generator company, thereby mitigating the impact of this new measure, there are a number of project financed IPPs (particularly those with Indonesian sponsors) that do not contemplate any such offshore share pledges. Lenders' inability to enforce share pledges during construction would constitute a fundamental impairment to lender security. As Regulation No. 42 applied to both new and existing IPPs, it was a particularly problematic proposition.

Less than one month after Regulation No. 42 entered into force, it was replaced by Regulation No. 48. Under this new regulation, MEMR consent is no longer required for share transfers (pre- or post-COD). However, pre-COD share transfers in a generator company are only permitted under Regulation No. 48 with PLN consent and only if they are transferred to a 90% owned affiliate. There is no express right for PLN to consent to any other transfers before COD.

While it is possible that MEMR did not mean to restrict share transfers on enforcement pre-COD and could allow these if PLN consents to them under the Sponsors' Agreement, Regulation No. 48 would take precedence over any contractual arrangements with PLN and could be applied to restrict these.

Regulation No. 48 therefore does not resolve the key bankability concern arising from Regulation No. 42 in respect of the enforceability of onshore share security pre-COD. Like Regulation No. 42 which it replaces, Regulation 48 applies to both new and existing IPPs.

Not There Yet…

For those who were hoping that Regulations No. 48, 49 and 50 would undo the problematic aspects of Regulations No. 10, 12 and 42, the answer seems, sadly, to be "not entirely." While some of the key investor concerns have been addressed by these regulations, such as MEMR's consent for share transfers pre-COD and relaxing the application of the Generating BPP caps to renewable tariffs, there are some problematic aspects (such as the right to enforce onshore share security pre-COD and PLN's right to invoke force majeure relief for change in law and force majeure affecting the grid) that will need to be addressed in a satisfactory manner (whether in the regulations or the PPAs themselves) to avoid affecting the bankability of future PPAs.

Energy Storage Update: Three More States Pass Initiatives to Encourage Electricity Storage Projects

By Donna J. Bobbish

In 2013, California became the first state to establish energy storage procurement targets to promote the development of energy storage projects. The California Public Utilities Commission (CPUC) established an energy storage target totaling 1,325 megawatts (MW) for California's three investor-owned utilities, Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). Under the CPUC's order, PG&E and SCE each must procure 580 MW of energy storage and SDG&E must procure 165 MW of energy storage by 2020. Installation of these energy storage resources must be completed by the end of 2024.

This past summer, Massachusetts, New York and Nevada joined the group of states initiating energy storage procurement targets.

Nevada

On June 1, 2017, Nevada Governor Brian Sandoval signed legislation requiring the Public Utilities Commission of Nevada (PUCN) to determine by October 1, 2018, whether it is in the public interest for utilities to procure "energy storage systems," defined as "commercially available technology that is capable of retaining energy, storing the energy for a period of time and delivering the energy after storage, including, without limitation, by chemical, thermal or mechanical means."

The Nevada legislature found that energy storage systems provide opportunities to reduce costs to ratepayers by avoiding or deferring the need for new generation of energy and for upgrades to systems for the transmission and distribution of energy; reduce the use of fossil fuels for meeting demand during peak load periods and providing ancillary services; assist electric utilities with integrating sources of renewable energy to the grids for the transmission and distribution of electricity and with enhancing grid stability; support diversification of energy resources and enhance grid security; and reduce the emission of greenhouse gases and other air pollutants.

In determining whether it is in the public interest for public utilities to procure energy storage systems, the PUCN must consider whether such procurement would achieve a number of results, including integration of intermittent renewable energy resources into the transmission and distribution grid; improvement in the reliability of electricity transmission and distribution systems; increased use of renewable energy resources to generate electricity; reduction in the need for additional electricity generation during peak demand periods; avoidance or deferral of electric utility investments in electricity generation, transmission and distribution; replacement of ancillary services provided by the use of fossil fuels with ancillary services provided by the use of energy storage systems; and reduction of greenhouse gas emissions.

If the PUCN determines that it is in the public interest to establish targets for electric utility procurement of energy storage systems, the new law requires the PUCN to adopt regulations that would, among other things, establish biennial targets for electric utility procurement of energy storage systems; provide that an energy storage system may be owned by an electric utility or by any other person; establish requirements for electric utilities to file on an annual or biennial basis plans to meet the biennial targets; and prescribe a procedure by which the PUCN must, at least every three years, reevaluate the biennial targets. The PUCN also must establish a procedure by which an electric utility may obtain a waiver or deferral of the biennial procurement targets if it is unable to identify energy storage systems that provide benefits to customers that exceed the cost of energy storage systems.

On July 13, 2017, the PUCN opened an investigation and rulemaking proceeding to implement the new legislation and scheduled a workshop for November 9, 2017, to discuss implementation of the legislation.

New York

In mid-June, the New York State Senate and Assembly passed legislation directing the New York State Public Service Commission (NYPSC) to develop an Energy Storage Deployment Program to encourage the installation of "Qualified Energy Storage Systems," defined as "commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy." The law provides that a Qualified Energy Storage System must be cost-effective and either assist the integration of variable energy resources, reduce emissions of greenhouse gases, reduce demand for peak electrical generation, defer or substitute for an investment in generation, transmission or distribution assets, or improve the reliable operation of the electrical transmission or distribution grid.

The legislation requires the NYPSC to commence a proceeding within 90 days to establish the energy storage deployment program, encourage installation of Qualified Energy Storage Systems and establish by January 1, 2018, a target for the installation of Qualified Energy Storage Systems to be achieved through 2030. The NYPSC also must establish programs that will enable the State of New York to meet the established target. The program established by the NYPSC would be administered by the New York Energy Research and Development Authority and the Long Island Power Authority.

The legislation also requires that the NYPSC's target determination include, among other things, program designs that take into consideration avoided or deferred costs associated with transmission, distribution and/or capacity, minimization of peak load in constrained areas; and systems that are connected to customer facilities and systems that are directly connected to transmission and distribution facilities.

The new legislation must be signed by New York Governor Andrew Cuomo.

Massachusetts

On June 30, 2017, the Massachusetts Department of Energy Resources (DOER) established an "aspirational" 200 MWh target, to be achieved by January 1, 2020, for electric distribution companies to procure viable and cost-effective energy storage systems. This action follows DOER's determination in late 2016 that it is prudent for the Commonwealth of Massachusetts to set targets for electric distribution companies to procure energy storage systems, pursuant to An Act Relative to Energy Diversity (Energy Diversity Act) signed by Governor Charlie Baker in August 2016. Among other things, the Energy Diversity Act required DOER to adopt energy storage procurement targets, if determined to be appropriate, by July 1, 2017.

The target established by DOER allows electric distribution companies to identify the most cost-effective applications and the best locations for energy storage deployment, including both in front of the meter and behind the meter.

The Energy Diversity Act also requires each electric distribution company to submit a report to DOER by January 1, 2020, providing information as to how they have complied with DOER's energy storage procurement target. DOER also has requested that electric distribution companies submit annual reports beginning on January 1, 2018, providing information on the amount of and cost-effectiveness of energy storage it has procured, and making recommendations for programs and policies to ensure the continued cost-effective deployment of energy storage. On the basis of the information it receives from electric distribution companies and its assessment of Massachusetts' experience with the initial energy storage procurement target, DOER will determine whether to set additional procurement targets beyond January 1, 2020.

Maryland Tax Credits

In May 2017, Governor Larry Hogan signed legislation under which Maryland became the first state to offer tax credits for energy storage procurement. The Maryland law provides an income tax credit, on a first-come, first-served basis, for 30% of the costs of installing an energy storage system on residential or commercial property between January 1, 2018, and December 31, 2022. The Maryland law defines an "energy storage system" as "a system used to store electrical energy, or mechanical, chemical, or thermal energy that was once electrical energy, for use as electrical energy at a later date or in a process that offsets electricity use at peak times." The Maryland Energy Administration is developing regulations to implement the new tax program, under which it would receive applications for and issue tax credit certificates that may not, in the aggregate, exceed $750,000 in a taxable year.

Editors

Robert N. Freedman
Partner
New York
T: +1 212 848 4340
robert.freedman@shearman.com

Patricia G. Hammes
Partner
Washington, D.C.
T: +1 202 508 8110
phammes@shearman.com

Contributing Authors

Bill McCormack
Partner
Singapore
T: +65 6230 3877
wmccormack@shearman.com

Donna J. Bobbish
Counsel
Washington, D.C.
T: +1 202 508 8089
donna.bobbish@shearman.com

Helen Cook
Counsel
Washington D.C.
T: +1 202 508 8156
helen.cook@shearman.com

Chelsea Gunter
Associate
Washington D.C.
T: +1 202 508 8134
chelsea.gunter@shearman.com

Jean-Louis Neves Mandelli
Associate
Singapore
T: +65 6230 3834
jean-louis.nevesmandelli@shearman.com