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"Looking Back … and Looking Ahead": Energy Sector Developments in 2015 That Will Continue to Shape the Energy Sector in 2016

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Transportation and Government Funding Bills Address Federal Energy Policy: Fate of Omnibus Energy Legislation Is Unclear

by Donna J. Bobbish and Monica Lamb

In December 2015, President Obama signed into law H.R. 22, the Fixing America's Surface Transportation Act (FAST Act), authorizing budgetary resources for surface transportation programs for fiscal years 2016-2020, and the Consolidated Appropriations Act, 2016 (Appropriations Act), an omnibus spending bill to fund the federal government through September 30, 2016. The FAST Act also contains provisions intended to improve the federal permit review process for major infrastructure projects, including energy projects, and the Appropriations Act lifts the 40-year-old ban on exports of US-produced crude oil and extends wind and solar tax credits for three years. While the FAST Act evidences bipartisan support for accelerating review of energy projects, and the Appropriations Act evidences congressional willingness to horse trade on energy issues important to each side, it remained unclear at the end of 2015 whether omnibus energy legislation pending before the 114th Congress will be passed and signed into law by the President in 2016.

FAST Act's Project Permitting Reforms

The FAST Act creates a Federal Permitting Improvement Steering Council which includes, among others, the Secretary of Energy and the Chairmen of the Federal Energy Regulatory Commission (FERC) and the Nuclear Regulatory Commission. The new Permitting Council is responsible for coordinating timetables among agencies that review projects and setting deadlines to accelerate required reviews for project approvals, including environmental review.

The projects covered by the new permitting process include infrastructure for renewable or conventional energy production, electricity transmission and pipelines that are valued at $200 million or more and subject to the National Environmental Policy Act of 1969 (NEPA).

The Permitting Council is required to create an inventory of major projects and establish model timelines for each infrastructure category. The lead agency for a given project would then establish a specific timeline for the project, consistent with the model schedule. Agency progress on granting approvals would be tracked by means of an online, public "dashboard." The FAST Act also reduces the time allowed for legal challenges to certain project permits, including environmental review under NEPA, from six to two years following the issuance of a project permit.

Appropriations Act Extends Tax Credits for Renewable Energy and Repeals Crude Oil Export Ban

The Appropriations Act grants significant extensions to the investment tax credit (ITC) for solar energy investments and to the production tax credit (PTC) for wind energy investments. Investments in other eligible renewable energy technologies were granted a one-year extension of the PTC.

The PTC, which expired at the end of 2014, will be extended (retroactively from January 1, 2015) for wind, closed-loop biomass, open-loop biomass, geothermal, landfill gas, municipal solid waste, qualified hydroelectric and marine hydrokinetic energy projects beginning construction through the end of 2016. After that, the PTC for all technologies except wind will expire, and the wind PTC will be decreased by 20%, 40% and 60% for wind projects beginning construction in each of the subsequent three years, finally expiring for wind projects that commence construction after the end of 2019.

The ITC for solar, which was set to drop to 10% for utility-scale projects and to expire completely for residential installations at the end of 2016, will be extended at the current 30% rate for projects that start construction by the end of 2019, 26% for projects that begin construction in 2020 and 22% for projects that begin construction in 2021, provided in each case that the projects complete construction by 2024. Solar projects that begin construction in 2022 and in later years will receive a 10% tax credit.

In return for extending the renewable tax credits favored by Democrats, the Appropriations Act repeals Section 103 of the Energy Policy and Conservation Act, which since 1975 prohibited the export of crude oil subject to certain exceptions granted by the Department of Commerce. The Appropriations Act further provides that no official of the federal government may impose or enforce any restriction on the export of crude oil, except for the President under the Constitution, pursuant to specified federal laws, or if the President declares a national emergency.

Pending Omnibus Energy Legislation

In early December, the House of Representatives passed, by a 249-117, largely party-line vote, H.R. 8, the North American Energy Security and Infrastructure Act of 2015, sponsored by House Energy and Commerce Chair, Fred Upton (R-MI). In late July, the Senate Energy and Natural Resources Committee voted out S. 2012, the Energy Policy Modernization Act of 2015, a broad, bipartisan energy bill championed by Committee Chair Lisa Murkowski (R-AK) and Ranking Member Maria Cantwell (D-WA). S. 2012 was approved by a vote of 18-4, including 10 Republicans and eight Democrats in support.

Both Senate and House energy bills contain, among other things, substantive changes to regulation of the natural gas, public utility and hydroelectric sectors by FERC and the US Department of Energy (DOE).

Electricity Sector Reforms

Among other things, H.R. 8 would require each Regional Transmission Organization (RTO) and Independent System Operator (ISO) that operates a capacity market or comparable market subject to FERC jurisdiction to provide to FERC an analysis of how the structure of that market utilizes competitive market forces in procuring capacity resources. It also includes resource-neutral performance criteria that ensure the procurement of sufficient capacity from physical generation facilities that have the following reliability attributes: (1) possession of adequate fuel onsite to enable operation for an extended period of time; (2) operational ability to generate electric energy from more than one fuel source or fuel certainty, through firm contractual obligations; (3) operational characteristics that enable the generation of electric energy for the duration of an emergency or severe weather conditions; and (4) unless procured through other markets or procurement mechanisms, essential reliability services, including frequency support and regulation services. HR. 8 further would require FERC to submit to the House and Senate energy committees a report containing an evaluation of whether the structure of each market addressed in an analysis meets the criteria and if it does not, recommendations with respect to the procurement of sufficient capacity.

H.R. 8 also would repeal Section 202(e) of the Federal Power Act (FPA), which requires prior authorization from DOE for the export of electric energy from the US to a foreign country.

H.R. 8 would clarify Section 203(a)(1)(B) of the FPA (which requires prior FERC authorization for a public utility to merge or consolidate, directly or indirectly, its facilities subject to FERC jurisdiction, or any part thereof, with those of any other person, by any means whatsoever) by limiting FERC review of such merger and consolidation acquisitions to those with a value of $10 million or more.

H.R. 8 would amend Section 319 of the FPA to require FERC to create an Office of Compliance Assistance and Public Participation to promote improved compliance with commission rules and orders. This office would be required to promote improved compliance with commission rules through outreach and publications and, where appropriate, direct communication with entities regulated by FERC.

Hydroelectric Sector Reforms

H.R. 8 would amend Sections 4(e) and 10 of the FPA to require FERC to minimize infringement on private property rights in issuing hydropower licenses, and to authorize FERC to issue exemptions from licensing requirements for developing new hydropower projects at existing non-powered dams.

S. 2012 would amend Section 5 of the FPA to extend from three to four years the total period for preliminary hydroelectric permits and would allow FERC to extend the period of a preliminary permit once, for not more than four additional years.

S. 2012 also would amend Section 13 of the FPA to allow FERC to extend the time period for beginning the construction of hydroelectric project works for not more than eight additional years.

S. 2012 would amend Section 15(e) of the FPA to require FERC, in determining the term of a hydroelectric license (other than an annual license), to consider project-related investments by the licensee over the term of the existing license (including any terms under annual licenses) that resulted in new development, construction, capacity, efficiency improvements or environmental measures, but which did not result in the extension of the term of the license by FERC.

Natural Gas Sector Reforms

For projects that must obtain authorization from FERC or the Maritime Administration to site, construct, expand or operate liquefied natural gas (LNG) export facilities, H.R. 8 would require DOE to issue a final decision on any application for authorization to export LNG under Section 3 of the NGA no later than 30 days after concluding the review to site, construct, expand or operate the LNG facilities required by NEPA. This entails publishing a Final Environmental Impact Statement or a Finding of No Significant Impact (FONSI), or determining that an application is eligible for a categorical exclusion under NEPA implementing regulations.

H.R. 8 also would amend Section 3 of the NGA to require DOE to condition any authorization to export LNG on the applicant publicly disclosing the specific destination or destinations of any authorized LNG exports.

For exports of US-produced LNG, where an export project requires approval from either FERC or the Maritime Administration to site, construct, expand or operate LNG export facilities, S. 2012 would require DOE to issue a final decision under Section 3(a) of the NGA to approve or disapprove an application to export natural gas to countries that do not have free trade agreements with the US (non-FTA countries) no later than 45 days after the FERC or Maritime Administration has concluded the review required by NEPA for such LNG export facilities. This means the publication of a Final EIS or a FONSI, or a determination that an application is eligible for a categorical exclusion under NEPA. In 2014, DOE/FE announced a new policy under which it acts on applications to export LNG to non-FTA countries only after completing the review required by NEPA, suspending its practice of issuing conditional decisions before final authorization decisions. Under this policy, DOE considers an application to have completed the NEPA review process 30 days after publishing a final EIS or a FONSI. Where FERC authorization to construct LNG facilities is required, DOE issues its decision after FERC has denied rehearing of its order granting authorization to construct the facilities.

S. 2012 also would expand the jurisdiction of the federal courts over LNG export authorizations. The bill would grant to the U.S. Court of Appeals for the District of Columbia Circuit or the circuit in which the LNG export facility will be located, original and exclusive jurisdiction over not only any petition for review of a DOE order issued for an application for export authority, but also DOE's failure to issue a final decision on such an application as required by the statute. If a court finds that DOE has failed to issue a final decision as required, it must order DOE to issue the decision no later than 30 days after the court's order. S. 2012 also would require the court to give expedited consideration to petitions for review filed under the new section.

In addition, S. 2012 would amend Section 3 of the Natural Gas Act to require DOE to obtain from applicants seeking authorization to export LNG the names of the countries to which the exported LNG is delivered and to publish such information on the DOE website.

Finally, in response to concerns about the effect of increased LNG exports on the price of natural gas in the US, S. 2012 would require the Secretary of Energy to submit to Congress a report analyzing, among other things, the economic impact that exporting LNG will have in regions that currently import LNG and on job creation in the manufacturing sectors.

Administration Opposition to H.R. 8

At the end of November, the Office of Management and Budget (OMB) issued a "Statement of Administration Policy," indicating that the Obama Administration "strongly opposes" H.R. 8 because it would undermine already successful initiatives designed to modernize the nation's energy infrastructure and increase our energy efficiency, and if the President were presented with H.R. 8, his senior advisors would recommend that he veto the bill.

In particular, the OMB Statement finds that the provision in H.R. 8 regarding certain operational characteristics in capacity markets operated by RTOs and ISO is "unnecessary," as FERC and the RTOs and ISOs "are already well positioned" to "ensure that capacity market structures adequately provide for the procurement of sufficient capacity to efficiently and reliably fulfill the resource-adequacy function that these markets are intended to perform." The Statement also criticizes as "unnecessary" the provisions of the bill that would broaden FERC's authority to impose deadlines on other federal agencies reviewing the environmental implications of natural gas pipeline applications. In addition, the Statement indicates that H.R. 8 would unnecessarily curtail DOE's ability to fully consider whether natural gas export projects are consistent with the public interest. Further, the Statement argues that H.R. 8 would undermine current hydropower license processes under the FPA by creating a new exemption from licensing.

It is not clear when the full Senate would vote on either S. 2012 or H.R. 8.

Paris Climate Summit: International Commitment to Reduce Emissions

by Jeff Salinger

The Paris climate summit (also known as COP21) adopted the Paris Agreement on December 12, 2015, creating binding procedures and non-binding emissions targets for participating nations. The Agreement was approved by 195 countries and will become effective once 55 countries accounting for at least 55% of global emissions have acceded to it.

While hailed as a breakthrough agreement to avert the harmful effects of climate change, it does not legally require emission cuts from any country or region. However, the transparency provisions and the requirements to establish, every five years, country-specific commitments to reduce emissions, are binding and promise to maintain focused attention on climate issues for the foreseeable future.

The Paris Agreement embodies the commitment to reduce global emissions from peak levels as soon as possible and imposes this obligation on all countries, rather than only on developed countries. Countries pledged "to achieve a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases in the second half of this century," which reflects the commitment to get to "net zero emissions" between 2050 and 2100. This is important because the UN's climate science panel has stated that net zero emissions must happen by 2070 to avoid dangerous warming.

Five Objectives of the Agreement

Broadly speaking, the Agreement achieves five objectives.

First, the Agreement sets aspirational goals to limit worldwide increases in temperature. Specifically, the text seeks to limit the increase in the global average temperature to "well below 2 degrees Centigrade above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 degrees Centigrade above pre-industrial levels." The 1.5-degree centigrade commitment seemed unachievable as recently as a few months ago, and constitutes a significant improvement on the 2-degree centigrade increase that nearly 200 countries had previously agreed to during the 2009 Copenhagen Climate Conference.

Second, the Agreement prompts countries to set national targets for reducing greenhouse gases, or GHGs. Before the Paris Conference began, more than 180 countries had submitted pledges to cut or curb their carbon emissions (in the form of "intended nationally defined contributions" or INDCs). Scientists concluded, however, that these INDCs would lead to a 2.7-degree centigrade rise or higher. As part of the deal, countries will be required to submit new emissions-reduction pledges every five years, starting in 2020. While the Agreement does not *require* countries to increase commitments for emission reductions, the goal is to pressure them to consider stronger action over time, and ideally, as emissions reduction technology becomes more readily available at lower price points.

Third, the Agreement establishes transparency rules to help pressure countries into achieving their proposed emissions reductions. These rules will also help others verify that nations are constraining their emissions in line with their commitments. Given the absence of binding requirements concerning actual emissions, we presume that international pressure, rather than international law, would be brought to bear against non-compliant countries.

Fourth, the Agreement encourages developed countries to offer financial support to poorer countries to help them reduce their emissions and adapt to climate change. This is because poorer countries will need help in adopting clean energy and adapting to climate impacts from increased global temperatures. Although the Agreement's $100 billion annual commitment by developed countries to poorer countries is non-binding, this provision is likely to further pressure developed countries to assist poorer countries with climate change adaptation costs and clean energy development projects. The Agreement provides that the countries "intend to continue their existing collective mobilization goal through 2025," meaning that the flow of $100 billion a year will continue beyond 2020. By 2025 the Agreement contemplates an increase of that amount, "from a floor of $100 billion."

Fifth, the Agreement addresses, albeit in limited fashion, small island nations' concerns regarding loss and damage from climate change. However, no liability or compensation provisions in favor of island nations were included in the final draft.

Looking Ahead

The Paris Agreement reflects a consensus view among nations that carbon emissions must be reduced significantly over the coming decades in order to avoid potentially catastrophic global average temperature increases of three degrees centigrade or higher.

By requiring evolving commitments to reduce carbon emissions, the Paris Agreement makes clear that renewable energy will be a crucial part of the world's future energy mix. The Agreement should also unlock significant public and private sector investments in carbon-neutral or carbon-reducing technologies. Investors should anticipate increased national and regional preferences for renewable energy, which by their nature do not involve the combustion of fossil fuels and the discharge of carbon-based emissions.

Iran Nuclear Deal: The Road Ahead Under JCPOA

by Helen Cook and Addison Pierce

On July 14, 2015, the P5+1 (the US, the UK, France, China and Russia, plus Germany), along with the European Union (EU) and Iran, reached an historic agreement curbing Iran's nuclear program in exchange for sanctions relief. The Joint Comprehensive Plan of Action (JCPOA) lays out a framework for lifting certain nuclear-related United Nations, EU and US sanctions against Iran. In exchange, Iran has agreed to considerably scale back its nuclear program and never to "seek, develop or acquire any nuclear weapons," a promise that will be verified by detailed inspections and monitoring by the International Atomic Energy Agency (IAEA). On October 18, 2015, the JCPOA was formally adopted, setting in motion a 10-year timeline under which sanctions relief will be phased in as Iran takes verified steps to fulfill its obligations.

On the horizon for the JCPOA is Implementation Day, expected in early to mid-2016, which will mark the beginning of the phased lifting of sanctions against Iran. For companies around the world looking to capitalize on business opportunities, it will be necessary to carefully assess the evolving sanctions environment and understand the risks inherent in venturing into the Iranian market. The first round of sanctions relief under the JCPOA will commence on Implementation Day, and updated guidance is expected to be issued by the EU and the US Department of Treasury's Office of Foreign Asset Control (OFAC).

JCPOA Timeline

Key dates under the JCPOA timeline:

Adoption Day - October 18, 2015	**JCPOA formally comes into effect** **EU**: Begins to adopt regulations lifting many of its nuclear-related sanctions targeting Iran, to be effective on Implementation Day **US**: President has issued sanction waivers in relation to so-called secondary sanctions, to be effective on Implementation Day
Implementation Day (Expected early 2016)	**UN, EU**: Most nuclear-related sanctions lifted; human rights-related sanctions remain in place, as do certain asset freezes **US**: Most secondary sanctions lifted; primary sanctions remain in force subject to limited licenses granted by OFAC to non-US entities that are owned or controlled by a US person to engage in activities with Iran that are consistent with the JCPOA
Transition Day (No later than October 18, 2023)	**UN, EU**: Lift remaining nuclear-related sanctions **US**: Formally terminates secondary sanctions which, since Implementation Day, ceased to be applied
Termination Day (No later than October 18, 2030)	**UN, EU**: Termination of all remaining EU sanctions; passing of UN Security Council resolution terminating Resolution 2231 (ending the UN involvement) **US**: No additional commitments

Prior to sanctions relief from Implementation Day, Iran must take a number of steps relating to its nuclear program, including reducing its enriched uranium stockpile, dismantling large parts of its nuclear infrastructure and completing the IAEA's roadmap for clarifying past and present outstanding issues regarding Iran's nuclear program. The roadmap report was issued by the Director General of the IAEA on December 2, 2015, and on December 15 the IAEA Board of Governors in a special session voted to adopt a new resolution closing the roadmap process and focusing the attention of the IAEA on implementing the JCPOA.

UN/EU and US Sanctions Relief Under JCPOA

UN/EU Sanctions Relief

On Implementation Day, the UN and EU will lift a range of sanctions:

- The UN Security Council (UN SC) will terminate all past resolutions relating to Iran's nuclear program and simultaneously suspend sanctions as long as the conditions of the JCPOA are met (Resolution 2231). These new restrictions generally entail UN SC oversight of UN members' planned trade with Iran in military or nuclear-related technology through a procurement working group.
- The EU will no longer prohibit EU persons from participating in Iran-related transactions, such as the transfer of funds between EU persons and entities and Iranian persons and entities; import and export of Iranian oil; and investment in the oil, gas and petrochemical sectors.

Both the UN and EU regimes will grant EU companies, banks and investors substantially greater access to the Iranian market than US companies and their foreign subsidiaries. However, companies subject to both EU and US rules may face difficult compliance issues.

US Sanctions Relief

The US currently imposes both primary and secondary nuclear-related sanctions against Iran:

- Primary sanctions are those applying to US persons, as well as non-US entities that are owned or controlled by a US person, non-US persons who cause US persons to violate sanctions maintained by OFAC and persons involved in transferring US-regulated goods or technology to Iran.
- Secondary sanctions generally apply to non-US persons and are intended to work by threatening non-US companies with the possibility of, among other things, being designated themselves as sanctions targets under US rules if they engage in transactions prohibited under the US secondary sanctions regime, even if those transactions take place entirely outside of US jurisdiction.

Under JCPOA, US primary sanctions remain largely unchanged. The US will not allow US persons, such as parent companies, to facilitate activity that US persons could not do themselves. The US financial system will remain off limits for transactions involving Iran. OFAC will also be able to license certain exports of commercial aircraft and related parts, and the import of certain foodstuffs and carpets.

In contrast, most US secondary sanctions will be waived on Implementation Day. Secondary sanctions that are to be lifted include, in relation to energy and petrochemicals, sanctions that to date have targeted persons engaged with Iran in transactions involving petroleum, petroleum products, refined petroleum products, petrochemical products or natural gas and liquefied natural gas, as well as the provision of goods and services related to supporting or facilitating those transactions.

In addition to limited primary and general secondary sanctions relief, the US will also begin to delist certain individuals from the Specially Designated Nations List, among others. This will allow non-US individuals to conduct transactions with these individuals. However, companies should be aware that certain individuals delisted from nuclear-related sanctions will remain subject to other US sanctions, such as those relating to terrorism and human rights violations.

Opportunities

Overview of Oil and Gas Opportunities in the Post-Sanction Environment

According to a 2015 British Petroleum Report, Iran has 18.2% of the world's proven gas reserves and 9.3% of the world's proven oil reserves. When sanctions against Iran are lifted, increased production and sales of gas and crude oil will present a source of significant revenue for Iran. Serious natural gas development is expected in the region as well. For example, Qatar's successes in the region have been based on reserves in the North Field (known as South Pars in Iran) which is shared with Iran.

Upstream opportunities are critical to the long-term viability of Iran's plan to play an important role in the global energy market. The National Iranian Oil Company (NIOC) in October announced its plan to introduce over 50 new oil projects immediately after the lifting of sanctions, increase oil production by 500,000 barrels per day within months, and return to its pre-sanction capacity of four million barrels per day. To achieve this goal, Iran will likely lean heavily on foreign investments.

Downstream projects announced by the Ministry of Petroleum include re-launching the development LNG liquefaction projects; terminal and oil tanks at Jask, Lavan and Siri; a pipeline from Goreh in Bushehr to Jask; and the Bahregan Oil Terminal.

The NOIC and Its Related and Subsidiary Companies

The petrochemical industry in Iran is controlled by the Ministry of Petroleum (MOP). The MOP controls the exploration, extraction, exploitation, distribution and exportation of crude oil and oil products, as well as the licensing for importing the same. Under the MOP are four major subsidiaries: the NIOC, the National Iranian Gas Company (NIGC), the National Petrochemical Company (NPC) and the National Iranian Oil Refining and Distribution Company (NIORDC). Each subsidiary is charged with a different mandate, and each has a further set of subsidiaries enabling it to carry out its obligations.

Under this system, the NIOC is responsible for all oil and gas exploration, production, refining and transportation. The Pars Oil and Gas Company (POGC) is a subsidiary of the NIOC, which is mandated to develop the South Pars gas field and North Pars gas field. Under this mandate, the POGC is responsible for awarding the contracts for different phases of development. The Petroleum Engineering and Development Company (PEDEC), also a subsidiary of the NIOC, is responsible for the buy-back projects under operation.

The NIGC is responsible for the treatment, transmission and delivery of natural gas to the domestic, industrial and commercial sectors and power plants. Transferred to NIGC's control in 2010 is the National Iranian Gas Export Company (NIGEC), which supervises all gas pipeline and LNG projects. Also under the NIGC are several development, storage and transmission subsidiaries.

The NPC is responsible for all petrochemical production, distribution and exportation. Output capacity of the NPC is expected to double from 2010 levels after sanctions relief. Finally, the NIORC handles oil refining and transportation, with some overlap of NIOC.

The Iranian Petroleum Regime

The Iranian constitution prohibits foreign persons from owning oil and gas reserves, as all rights in oil and gas are vested exclusively in the NIOC. Only the NIOC can explore, extract, transport and export crude oil, natural gas and LNG.

To exploit its resources, the NIOC has traditionally entered into long-term contracts on a "buy-back" basis. Buy-back contracts are arranged such that the contractor funds all of the investment and then receives remuneration from the NIOC in the form of an allocated production share. After a set number of years, the contract is considered complete and the NIOC owns the facility outright. In 2007, the scheme was altered to allow contracts to extend for as long as 20 years. This system was the primary means by which Iran attracted foreign investment.

However, the model was widely criticized by international oil companies (IOCs) for low rates of return, inflexible terms and short-term involvement of contractors in projects. In an effort to attract necessary capital and technology, NIOC undertook wide-ranging review, headed by a restructuring committee, which engaged in consultation with IOCs to develop a more investor-friendly regime. According to NIOC, however, "The key issue is that the reserves in the ground remain with the state, which is exactly in line with the term's production sharing agreements — and crucially in line with the Iranian constitution."

After much anticipation, a recent two-day conference in Tehran introduced the new Iran Petroleum Contract (IPC). Although full and final details are still to be released, the conference did introduce 52 projects, including 14 exploration and development blocks, along with major onshore and offshore fields such as South Azadegan and the North Pars gas field. The exact date of the tenders' release will reportedly depend on feedback from IOCs at the Tehran summit, but there are hopes to finalize the contracts by the end of next year.

The IPC sets the basic structure for all future petroleum contracts with the State of Iran. It was passed under the Petroleum Act as a Cabinet Resolution. However, as the Iranian constitution requires the Iranian parliament to approve international agreements, political sensitivities will still need to be considered. It has been described as a "risk service contract," which is designed to spread investment risk on a sliding scale for a foreign investor and offer more flexibility in terms of collaboration, competitive terms, pricing and booking of reserves to the foreign investor. IOCs in the Iranian upstream energy sector will be expected to sign an IPC. To sign an IPC, IOCs will have to form a consortium (operator) with at least one Iranian domiciled oil company (LOC). The consortium can be incorporated or unincorporated, and there will be no fixed minimum equity participation requirement for the LOC.

Iran has said that a key difference between the new and old contracts will also be that companies will be able to maintain involvement in a project from the exploration phase through development and on to production, including any agreed improved/enhanced oil recovery (IOR/EOR). Another benefit is said to be that cost recovery will begin on the first day of production from a project. From first production, the operator is paid fees on a per-barrel recovered basis, and fees will be calculated by reference to an "R" factor tied to a crude oil price index and will include a premium for smaller and riskier projects. Further, costs will be recovered from the production and sale of oil. However, the "cost" of oil will be capped at 50%, and all financial risk will remain with the contractor or foreign oil company. Foreign contractors must commit to improving Iranian know-how and technology, and employ Iranian nationals as much as possible.

Interested parties must wait until February 2016, however, for further details about the IPC. Until a copy of the IPC is available, many questions will remain, including the required form of the investment vehicle, the form of obligations arising from joint operating agreements, resolving disputes within the managing working group, governing law and dispute resolution arrangements. The risks associated with "snapback" (as discussed below) are not within the NIOC's control and will need to be considered very carefully.

Considerations When Dealing in or with Iran

Violation of US Sanctions

OFAC advises that the US government will continue to vigorously enforce both primary and secondary sanctions targeting Iran until Implementation Day. To that end, OFAC recommends that businesses be "exceedingly cautious" in exploring talks with Iranians before the lifting of sanctions, as arranging for contracts or services to begin after Implementation Day is a violation of current sanctions.

Post-Implementation Day, businesses will need to be acutely aware of the narrow nature of the relief granted as it pertains to US persons. While EU and other non-US persons will have substantial freedom to deal with Iran, US persons are limited to only those exceptions provided by OFAC licensing. Outside of these exceptions, US persons will generally remain prohibited from engaging in economic activity involving Iran, its persons and its entities.

There appears to be a significant advantage for non-US financial institutions under the JCPOA to be able to conduct business with Iran. In reality, however, the position is likely to be more nuanced, with non-US financial institutions remaining cautious about doing business with Iran for fear of incorrectly navigating the complex US primary sanctions regime. In short, those non-US financial institutions which treat themselves as US persons for the purpose of sanctions compliance in many respects (generally to avoid inadvertently coming into the fold of and breaching US rules) may continue to follow US rules. US subsidiaries of foreign companies and foreign companies with certain other ties to the US will remain prohibited from engaging in economic activity involving Iran. Transactions in US dollars and through US banks will also remain prohibited.

The Risk of "Snapback"

A risk for those looking to deal in and with Iran is the possibility that sanctions will "snap back"—the undoing of all granted sanctions relief under the JCPOA. Of greatest concern may be the ease with which snapback can occur. The JCPOA allows participant states to dispute Iran's fulfillment of its commitments before the UN SC and requires Iran to resolve the matter. If unsatisfied with Iran's response, the JCPOA requires the UN SC to vote on a resolution to continue the phased lifting of sanctions. If the resolution fails to pass, all currently lifted sanctions will "snap back" into place.

Moreover, the JCPOA does not provide any assurances to protect commercial contracts permissively formed prior to any snapback. The recital states that "[i]n case of reintroduction of Union sanctions, adequate protection for the execution of contracts concluded in accordance with the JCPOA while sanctions relief was in force will be provided consistent with previous provisions when sanctions were originally imposed." According to the White House, "there is no grandfathering clause…if snapback does occur, there are no exemptions from our sanctions for long-term contracts."

The US Office of Foreign Assets Control has advised US businesses that contracts with Iranians must include provisions to enable termination of the contract if sanctions are snapped back. Presumably, the consequences of termination in such circumstances will be a matter for commercial negotiation between parties. European businesses may be similarly advised. Companies will also want to consider appropriate contractual provisions governing demobilization and exit strategies.

Iranian Business Landscape

A final concern about conducting business in Iran is the relatively unchartered business environment. The World Bank ranks Iran as 130 in its Ease of Doing Business report, 172 in the area of construction permits, and 161 for property registration. The World Bank also cites poor trade, tax and investor protection regimes as business concerns. The UK Department for Business, Innovation and Skills has stated in a recent notice to business that "[e]ven as sanctions are lifted Iran will remain a challenging place to do business, and banks and other financial institutions may remain reluctant to handle Iran-related transactions while full US sanctions remain in place."

Iran has passed laws to attract foreign direct investment, namely the 2002 Foreign Investment Promotion and Protection Act. Although the Act does allow for 100% foreign ownership, as sanctions are eased and foreign ownership swells, the relatively untested law may come under scrutiny.

Iran's banking and financial sector, which may benefit significantly from regulatory and structural reform, is reportedly likely to be constrained in spite of internal moves to reform. Financial institutions wishing to establish operations in Iran would need to obtain a regulatory license from the Iranian government.

Of course, companies should always be sensitive to the wide-ranging extraterritorial scope of some anti-corruption laws, such as the US Foreign Corrupt Practices Act and the UK Bribery Act.

Final Thoughts

As companies seek to capture significant opportunities arising out of the JCPOA and related sanctions relief, the risk of non-compliance with US sanctions, risk of sanctions snapback, high political risk and other legal and regulatory risks will need to be carefully assessed, managed and mitigated. Primary sanctions will continue to apply in and be enforced by the US. The complicated process of lifting UN, EU and US secondary sanctions will continue to evolve in the lead up to Implementation Day, but until then, enforcement agencies have reminded us that all sanctions remain in force.

Court Update: U.S. Supreme Court Explores Boundaries of Federal/State Jurisdiction over Natural Gas and Electricity Markets

by Donna J. Bobbish

Decisions by the U.S. Supreme Court in 2015 and 2016 examine whether regulation by the Federal Energy Regulatory Commission (FERC) of electricity and natural gas markets oversteps the boundary between state and federal jurisdiction over those markets and to explain how the boundary might be drawn. Three cases ─ one decided and two pending ─ address “field preemption,” where Congress intends to foreclose any state regulation in a particular area, as opposed to “conflict preemption,” which exists where compliance with both federal and state law is impossible.

Under the Natural Gas Act (NGA), FERC has jurisdiction, among other things, over wholesale sales and transportation of natural gas in interstate commerce. Under the Federal Power Act (FPA), FERC has jurisdiction over, among other things, the sale and transmission of electricity at wholesale in interstate commerce. Regulation of retail sales and local distribution of natural gas and electricity is subject to state regulation.

In April 2015, in a 7-2 decision,[1] the Supreme Court affirmed a decision by the U.S. Court of Appeals for the Ninth Circuit that antitrust claims made against an interstate pipeline under state law are not preempted by the NGA, because the claims were aimed at practices affecting retail prices, a matter firmly on the states’ side of the dividing line between federal and state jurisdiction. In *Oneok*, a group of companies that purchase natural gas directly (at retail) from interstate natural gas pipelines sued the pipelines, alleging that the pipelines’ manipulation of natural price indices violated state antitrust law. The pipelines argued that the antitrust suits target activities that affected wholesale as well as retail rates and therefore are preempted by the NGA’s provisions giving FERC jurisdiction over wholesale natural gas rates. The Supreme Court ruled that where a state law can be applied to sales subject to state jurisdiction as well as sales not subject to state jurisdiction, preemption can be found only where a detailed examination convincingly demonstrates that a matter falls within the preempted field, and that the target at which the state law aims must be considered in determining whether the law is preempted.

In his dissenting opinion, Justice Scalia (joined by Chief Justice Roberts) claimed that the Supreme Court’s decision “smudges” the line between federal and state jurisdiction over trade in natural gas.

In 2016, the Supreme Court may have occasion to apply its *Oneok* decision to two pending cases under the FPA.

1 *Oneok, Inc., et al. v. Learjet, Inc., et al., 575 U.S.* ___ (2015) (“*Oneok*”).

In May 2015, the Supreme Court granted FERC's petition for *certiorari* to review a 2014 decision by the U.S. Court of Appeals for the District of Columbia Circuit that vacated in its entirety FERC Order No. 745.[2] The order required that a demand response resource participating in an organized wholesale energy market must be compensated for the service it provides at the market price for energy when the demand response resource has the capability to balance supply and demand as an alternative to a generation resource and when the dispatch of the demand response resource is cost-effective.[3]

The D.C. Circuit found that demand response is "part of the retail market" and that "a reduction in consumption cannot be a wholesale sale." The court concluded that, in Order No. 745, FERC had "encroach[ed] on the states' exclusive jurisdiction to regulate the retail market."

The Supreme Court heard oral argument in the case in October 2015.[4]

Also in October, the Supreme Court agreed, over FERC's objections, to review a decision by the U.S. Court of Appeals for the Fourth Circuit,[5] which held that the FCPA preempted incentive pricing established by the Maryland Public Service Commission for new generation that cleared the PJM market and that is different from the price the same generation would receive in wholesale markets under rules established by FERC.

Oral argument in the case has been scheduled for February 24, 2016.[6] The Supreme Court has not yet decided whether or not to grant *certiorari* with respect to a decision by the U.S. Court of Appeals for the Third Circuit finding that a similar incentive program in New Jersey is preempted by the FPA.[7]

2 *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011), *reh'g denied*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *reh'g denied*, Order No. 745-B, 138 FERC ¶ 61,148 (2012).

3 *EPSA v. FERC*, 753 F.3d 216 (D.C. Cir. 2014)

4 *FERC v. EPSA*, No. 14-840 and *Enernoc, Inc., et al., v. EPSA*, No. 14-841.

5 *PPL Energyplus, LLC. v. Nazarian*, 753 F.3d 464 (4th Cir. 2014).

6 *Nazarian v. PPL EnergyPlus, LLC*, No. 14-614, and *CPV Maryland LLC v. PPL EnergyPlus, LLC*, No. 16-623.

7 *PPL Energyplus, LLC v. Solomon*, 766 F.3d 241 (3d Cir. 2014).

DOE Extends Up to $1 Billion in Additional Loan Guarantees for Distributed Energy Projects

by Monica Lamb

Program Expansion

The US Department of Energy (DOE) has expanded the availability of DOE loan guarantees for distributed energy projects utilizing innovative technologies. On August 24, 2015, DOE invited innovative distributed energy projects to apply for the more than $10 billion currently available under existing solicitations[8] and added up to $1 billion in additional guarantee authority for such projects.[9]

Section 1703 of the Energy Policy Act provides loan guarantees to support financing of new or significantly improved technology that is not a commercial technology, meaning it is not in general use in the United States, or installed or operating in three or more commercial projects in the United States for five years or more.

The DOE guidance came in the form of supplements to the existing Section 1703 solicitations DE-SOL-007154 (renewable energy and energy efficiency) and DE-SOL-0006303 (advanced fossil energy), which expire on November 30, 2016. The guidance clarified how distributed energy projects can qualify for loan guarantees under these two solicitations.

Defining "Distributed Energy Projects"

The supplements, issued on August 24, 2015, define qualifying projects (Distributed Energy Projects) as projects comprised of facilities utilizing a single technology, or a defined suite of technologies (a Distributed Technology), at multiple sites, deployed pursuant to a master business plan. DOE stated in the supplements that "Distributed Energy Projects utilizing innovative technology are not being deployed at scale due in part to capital constraints associated with the structuring of

8 The applicable existing solicitations are for Renewable Energy and Energy Efficiency Projects and Fossil Energy Projects using new technologies under Title XVII.

9 US Department of Energy press release, Fact Sheet: President Obama Announces New Actions to Bring Renewable Energy and Energy Efficiency to Households across the Country.

Distributed Energy Projects and the innovative technologies that such projects use." The guidance is meant to help overcome that hurdle to encourage deployment of Distributed Energy Projects.[10]

Eligible Financial Structures

The DOE supplements outline three different eligible structures for a single financing arrangement for multiple installations:

I. The borrower develops, constructs, operates and owns revenue-generating assets consisting of multiple installations of Distributed Technology at multiple sites. The sites where the installations are located are either owned by a single creditworthy party or secured in a highly standardized manner that protects against the potentially unrated credit of the site owners. The borrower sells energy under a single energy offtake arrangement with a creditworthy power purchaser for at least the term of the loan.

II. The borrower earns revenue from standardized contracts, such as equipment leases or power purchase agreements, with multiple host site-owners that meet pre-defined credit criteria pursuant to a master business plan. The master business plan may provide for installations of Distributed Technology using two or more installers. The borrower may not merely re-lend DOE-guaranteed loan proceeds to project hosts for "unreasonable profit."

III. The borrower operates a mobile technology and earns revenues from the temporary set-up and operation of such technology at multiple customer sites.

In each case, the borrower would be expected to use highly standardized contract forms for site hosts, other project contracts and services. DOE would be a senior lender with full recourse to adequate security and would control loan disbursements. The program will not support portfolios of multiple unrelated projects. Instead, the projects must be part of a clear master business plan.[11]

Eligible Technologies

Distributed Energy Projects that meet the solicitation qualifications are eligible under the existing Section 1703 solicitations DE-SOL- 007154 (renewable energy and energy efficiency) and DE-SOL-0006303 (advanced fossil energy), each of which expire on November 30, 2016. The renewable energy and energy efficiency solicitation identifies five target innovative technology areas: (1) Advanced Grid Integration and Storage, (2) Drop-in Biofuels, (3) Waste-to-Energy, (4) Enhancement of Existing Facilities and (5) Efficiency Improvements.[12] The advanced fossil energy solicitation targets innovative technologies in four areas: (1) Advanced Resource Development, (2) Carbon Capture, (3) Low-Carbon Power Systems and (4) Efficiency Improvements.[13] The supplements to the solicitations provide examples of Distributed Technologies that could be eligible, including:

10 US Department of Energy Third Supplement to Loan Guarantee Solicitation Announcement Federal Loan Guarantees for Renewable Energy and Energy Efficiency Projects DE-SOL-0007154.

11 *Id*.

12 US Department of Energy Fact Sheet, Renewable Energy and Efficient Energy Projects Loan Guarantee Solicitation.

13 US Department of Energy Loan Guarantee Solicitation Announcement Advanced Fossil Energy Projects.

Grid Infrastructure and Storage

- Distributed grid infrastructure and storage technologies that mitigate issues related to distributed generation using functionality such as active demand management, integration of both utility and customer-owned storage assets, frequency and voltage regulation.
- Distributed storage technologies that provide consumers greater flexibility in managing their energy, while being available to grid operators for system reliability and stability services.
- Smart grid technologies and software systems that enable improved asset utilization for grid operators.
- Advanced Distribution Management Software.
- Distribution Automation—Sensors, actuators and associated software and data transmission methods.
- Active Demand Management Systems.
- Smart inverters or other technologies that allow voltage variability control.

Energy-Efficient Buildings and Installations

- Zero Energy or Low-Carbon building technologies and installations that reduce energy consumption in a building, campus or complex.
- The distributed energy component of energy-efficient buildings or building technologies that significantly reduce lighting usage, thermal heat loss and plug loads.
- Passive building technologies that reduce the demand for heating and cooling.
- District cooling systems that utilize renewable energy, such as deep cold sea, lake or river water.
- High-efficiency distributed generation and transmission systems that provide any combination of power, heat or islanding capabilities and improve or reduce energy usage.
- The distributed energy component of building energy systems that enable active demand management and storage.
- Energy generation, including distributed generation, incorporating storage.
- Smart grid systems incorporating any combination of demand response, energy efficiency, sensing and storage.
- Landfill methane to power gas turbines or fuel cells.

Distributed Power Generation

- Decentralized power or thermal energy generation projects that incorporate new or significantly improved technology at a scale smaller than traditional utility-scale projects.
- Distributed renewable energy generation that may be combined with storage including solar photovoltaic installations such as solar gardens; rooftop solar or building integrated solar; wind; geothermal; or modular low-head hydropower systems along a single structure or body of water.
- Distributed cogeneration or combined heat and power including biofuels, biogas, landfill gas and sewage gas. Under the advanced fossil fuel solicitation, generation could include steam turbines, natural gas fuel cells, microturbines or reciprocating engines with the hot exhaust used for heating or cooling, low carbon fuels, coal bed methane, syngas and associated petroleum gas.
- Distributed thermal heating or cooling installations including solar thermal and ground-sourced geothermal.
- Waste energy recovery and use from thermal, mechanical, electrical, chemical or hydro-processes.
- Distributed carbon capture and use.
- Distributed methane recovery and use such as small-scale liquefied natural gas or landfill gas collection.

Energy Security and Climate Change Stoke Growth of Nuclear Energy

by Helen Cook

Introduction

2015 witnessed the long-awaited entry into force of the Convention on Supplementary Compensation for Nuclear Damage (CSC) and the first reactor restarts in Japan since the accident at the Fukushima Daiichi Nuclear Power Plant in March 2011. The growth of nuclear energy in Asia continues, with 46 of 70 reactors under construction. Around the world, five new reactors (one in Argentina, three in China and one in Russia) were connected to the grid in 2015 and construction commenced on three new plants: Belarusian-2 in Belarus, Barakah-3 in the United Arab Emirates and CAREM-25 in Argentina. While projections for global nuclear energy growth remain mixed, energy security and climate change continue to be strong drivers towards an expanding nuclear energy future.

CSC Enters into Force

The CSC entered into force on April 15, 2015, following Japan's deposit of an instrument of acceptance. The CSC is intended to establish a global regime governing third-party liability for nuclear damage by allowing a country to join if it is a contracting party to either the Paris Convention or the Vienna Convention, or if it submits a declaration to the IAEA that its national law complies with the key principles of nuclear liability set out in the Annex to the CSC. Currently, the CSC has the following seven contracting parties: Argentina, Japan, Montenegro, Morocco, Romania, the United Arab Emirates and the United States of America. As between these contracting parties, the CSC provides for exclusive and strict channeling of third-party liability for nuclear damage to the licensed operator, availability of minimum levels of compensation consistent with contemporary standards, exclusive jurisdiction of the courts of one state, choice of law and, if compensation under the applicable national law is inadequate, contribution by contracting parties of additional international funds to supplement the amount of available compensation.

Japanese Reactor Restarts and New Government Targets for Renewable Energy, Including Nuclear

In September 2015, Kyushu Electric Power Co.'s Sendai 1 unit became the first Japanese nuclear reactor to commence normal operations. Japan had shut down all its nuclear power plants in the wake of the accident at the Fukushima Daiichi plant in 2011. Sendai 2 was restarted in November. All other operable reactors in Japan remain shut pending confirmation they meet the Japanese Nuclear Regulatory Authority's safety requirements and obtain permission from local authorities. In December 2015, Takahama Town announced that it had agreed to the restarting of the Takahama-3 and -4 Nuclear Power Plants (PWRs, 870 MWe each), owned and operated by the Kansai Electric Power Co. The Nuclear Regulation Authority had confirmed in October that the reactors had completed the steps required to conform with the new regulatory requirements for light-water reactors.

In November 2015, Japan's Ministry of Economy, Trade and Industry (METI) established a target of 44% of the country's power to be sourced from nuclear and renewable energies (including hydro) by April 2030.

Paris Climate Talks and the Role of Nuclear in Combating Climate change

The 21st Conference of the Parties to the United Nations Framework Convention on Climate Change (COP21) has given supporters of nuclear power a platform from which to extol its virtues. Leading climate scientists have done just that and called for a major expansion of nuclear power as an essential measure to avoid climate change over the next century. Supporting the role of nuclear in minimizing climate change, The Organisation for Economic Cooperation and Development (OECD) Nuclear Energy Agency's report "Nuclear Energy: Combating Climate Change" suggests there are only two options ─ nuclear power and renewable energy sources ─ to decarbonize an ever-expanding electricity sector and, of those, only nuclear provides "firmly dispatchable" baseload electricity.

In the context of the potential role of nuclear power in mitigating global climate change, the NEA questions, "[c]an nuclear power be expanded rapidly enough to make a full contribution to combating climate change?," referencing obstacles that have and are currently challenging the development of new nuclear power plants. Such obstacles include cost (including cost of alternatives such as gas) and access to finance, as well as nuclear safety, security and non-proliferation concerns, together with long-term radioactive waste management solutions. The policies of governments around the world will largely drive nuclear energy's role in combating climate change.

Nuclear Finance

For a project requiring access to large amounts of funds, the possible funding sources are currently relatively limited. Nevertheless, new nuclear project sponsors, including technology providers, need to seek and secure sources of finance, including private sources, and are therefore keen to develop project development and financing structures and models that will be acceptable to export credit agencies (expected to be primary sources of nuclear finance), commercial banks and other lenders and investors.

Project sponsors and the nuclear industry need to develop clear and credible solutions to real and perceived challenges in nuclear new build projects and articulate them in a manner that facilitates effective communication with banks. A significant portion of banking language is centered on "risk." In the nuclear sector, risks are prevalent ─ in perception and reality ─ and include both financial risk and reputational risk.

George Borovas and Helen Cook considered how to overcome barriers between the nuclear industry and financial institutions in their article "Nuclear Finance: Understanding and Speaking the Language of Banks," published in the *Journal of International Banking and Financial Law*. They argue that effective communication, in particular about risks, is essential for the creation of bankable nuclear projects. Effective communication includes talking early and often, demystifying "nuclear," and translating nuclear industry terms into banking reality.

Key Market Developments

In October 2015, EDF and China General Nuclear Power Corporation (CGN) announced a partnership for developing nuclear power plants in the United Kingdom, including signing a Strategic Investment Agreement for constructing and operating the proposed Hinkley Point C nuclear power plant, under which CGN will take a 33.5% equity stake in the project. In addition, the agreements between EDF and the UK government were announced to be in "final agreed form." Such agreements include the "Contract for Difference" (CfD) which sets a price for Hinkley Point C's electricity of £92.50 per MWh for 35 years or £89.50 per MWh if a final investment decision is taken on the second plant at Sizewell C. The Energy Secretary will reportedly make her final decision on the Contract for Difference when EDF and CGN have signed the full investment documentation. In addition, the UK Treasury, through Infrastructure UK, agreed to provide a financial guarantee of £2 billion under the UK Guarantee Scheme, with further amounts potentially available in the longer term. This scheme allows HM Treasury to provide support in the form of "an unconditional and irrevocable financial guarantee of scheduled principal and interest in favour of a lender to/investor in a UK infrastructure project" (each guarantee provided under the Scheme is tailored specifically to the project but effectively substitutes the UK government, and its credit rating, for the relevant borrower/issuer of debt).

The UK government's support of Hinkley Point C faces further challenge despite the European Commission's investigation concluding that the UK government's measures did not constitute illegal State Aid. For further information on the decision, see the Shearman & Sterling Client Briefing, "European Commission Approves Hinkley Point C State Aid." This decision is being challenged before the European Court of Justice by the Austrian Government in Case T-356/15: Action brought on 6 July 2015 - *Austria v Commission* and also by Greenpeace Energy eG and others in Case T-382/15: Action brought on 15 July 2015 - *Greenpeace Energy and Others v Commission*.

In addition to Hinkley Point C, the nuclear power projects being developed by NuGeneration and Horizon both made rapid progress in 2015 and are likely to gather momentum in 2016.

In other developments, Egypt and Russian state nuclear provider Rosatom signed an agreement on November 19, 2015 to collaborate in the construction and operation of a nuclear power plant equipped with four NPP units with capacity of 1,200 MW each at El-Dabaa. Poland announced that it will proceed with its nuclear program, and the Czech Republic developed a new national energy policy, which includes the future development of new units at both the Dukovany and Temelin sites. Fennovoima, together with Rosatom, submitted key license and permit applications for its nuclear power Hanhikivi 1 plant in Finland. China signed an agreement with Argentina to finance and build two nuclear power plants in Argentina. The Korea Atomic Energy Research Institute (KAERI) ─ designer of the SMART (System-integrated Modular Advanced Reactor) ─ and Saudi Arabia's King Abdullah City for Atomic and Renewable Energy (KA-CARE) signed agreements throughout 2015 to cooperate in the commercialization and deployment of the SMART reactor in Saudi Arabia and in third countries.

In November 2015, the Obama Administration in the United States announced actions intended to ensure that nuclear energy remains a component of the US' Clean Energy Strategy. The President's FY 2016 Budget includes more than $900 million for the Department of Energy (DOE) to support the US civilian nuclear energy sector by leading federal research, development and demonstration efforts in nuclear energy technologies. DOE will be supplementing its $12.5 billion loan guarantee solicitation, available to support innovative nuclear energy projects, in order to drive innovation and growth across the nuclear power sector. Other actions to sustain and advance nuclear energy include establishing the Gateway for Accelerated Innovation in Nuclear to provide the nuclear energy community with access to the technical, regulatory and financial support necessary to move new or advanced nuclear reactor designs toward commercialization.

2016 – Looking Ahead

In addition to the Hinkley Point C project in the UK, for which a final investment decision is expected shortly, both the Horizon and NuGen projects continue to move ahead. For the Horizon project, owned by Hitachi Limited, the Office for Nuclear Regulation (ONR) moves to Step 4 of the Generic Design Assessment (GDA) of Hitachi's UK Advanced Boiling Water Reactor. NuGen, sponsored by Toshiba and Engie (formerly GDF Suez), will be preparing its nuclear site license, as NuGen has informed ONR that it intends to apply for a nuclear site license for Moorside in 2017 with a view to the license being granted in 2018. The GDA process for NuGen's Advanced Passive 1000 reactors will continue in 2016. Both Horizon and NuGen are in the public consultation phase of the development consent process with further consultations to be run in 2016. As they progress through the various approval processes, both projects may seek UK government support and require State aid clearances.

2016 promises to be a big year for the Barakah 1 nuclear power plant in the UAE, which is heading for a May 2017 completion date for Unit 1. Unit 1 is more than 81% complete and Unit 2 is almost 60% complete. The Emirates Nuclear Energy Corporation (ENEC) will continue working to obtain the approval of the Operating License from the Federal Authority for Nuclear Regulation (FANR) for Units 1 and 2. The first four units are scheduled to be completed by 2020, when Unit 4 is connected to the grid. ENEC has stated that it may soon be ready to commence the procurement process for more units, possibly also at the Barakah site.

Tenders for new units which may be launched in 2016 include from Poland's state-owned Polish Energy Group (PGE). PGE announced in November that it is in discussions with Westinghouse, GE Hitachi, SNC-Lavalin Nuclear, Areva, EDF, and KEPCO, and will launch a tender in 2016 for reactor technology.

Long discussed and awaited, 2016 may be the year for the launch of South Africa's procurement. The country has already signed intergovernmental agreements (IGAs) with several vendor countries that have expressed interest in its nuclear new build program. The program is expected to include multiple PWR units and require strong government support, as well as commitments on localization and technology transfer.

Mexico, the Czech Republic and Bulgaria are also on the list of possible 2016 procurements.

In addition to new procurements and construction, the nuclear energy sector will also be focused on plant upgrades and license extensions, radioactive waste management and decommissioning. Of the currently 438 operational nuclear power reactors, 225 have been in service for 30 years or more.

The Duck Curve Revolution and Natural Gas

by Christopher Dolan

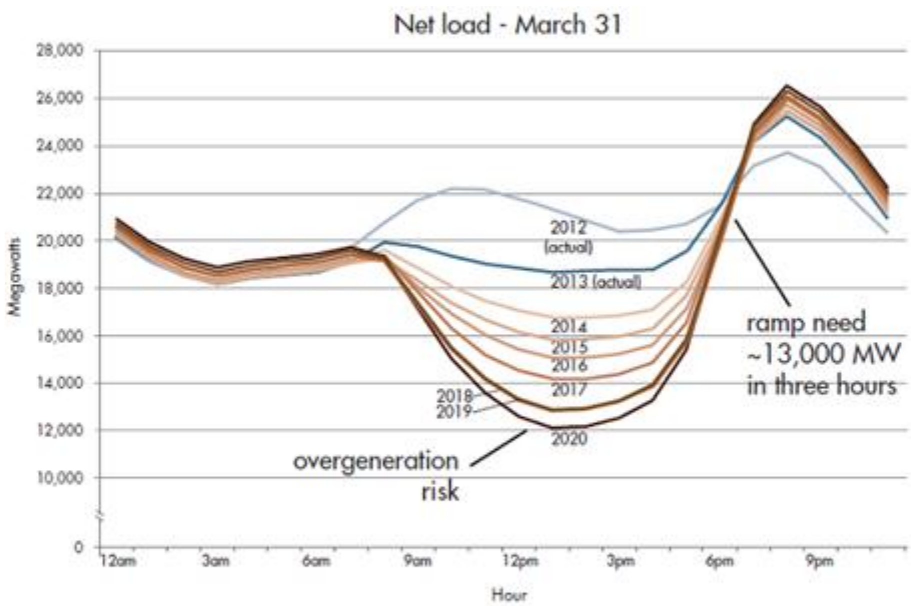
California has become the front-runner in what may be termed the "duck curve revolution," due to the plunge in photovoltaic panel prices over the last several years, paired with regulatory incentives to increase the proportion of renewables, including a statutory mandate to have 50% of generated electricity come from renewable sources by 2030. Green power advocacy groups have long pushed for an increased share of renewables in California's energy mix. The legislature responded, adopting SB350—the Clean Energy and Pollution Reduction Act of 2015—on October 7, 2015. The Act increased the proportion of renewable energy required to be in place by 2030 from 33% to 50%.[14] Going further, Governor Jerry Brown announced a goal of reducing emissions to 40% below 1990 levels by 2030.[15] California's solar industry has also responded, with large-scale solar accounting for 7,000 MW in 2015 and rooftop residential and business accounting for 3,000 MW.[16]

All of this new emphasis on solar power has displaced (and will continue to displace) conventional power generation, which has the California Independent System Operator (CAISO) concerned about demand response, grid reliability and frequency regulation. These three risks and the behavior of the net load curve have created significant demand for rapid response power generation, which, in today's energy world, effectively means gas-fired generation. For an example of the inherent tension in building new gas-fired power plants as part of the solar boom, look no further than the political debate surrounding the April 2015 approval of the 500-MW Encina gas peaker station.[17]

What in the World Is the "Duck Curve?"

The "duck curve" is an industry moniker popularized by CAISO to describe the shape of the net load curve of variable generation demand as renewable sources connect to the grid. The curve includes four distinct ramp-up and ramp-down periods in a typical day, particularly aggravated in the "shoulder" months in the spring and fall, when baseload will typically not be significant due to the temperate climate. Below is an example of the duck curve from CAISO for what would be a typical March day.

14 https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350
15 http://gov.ca.gov/news.php?id=18938
16 http://www.bloomberg.com/news/articles/2015-10-21/california-s-duck-curve-is-about-to-jolt-the-electricity-grid
17 https://www.greentechmedia.com/articles/read/California-PUC-Approves-500MW-of-Gas-For-SDGE-in-Carlsbad-Rejects-Alterna



Source: https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

According to CAISO, the neck of the curve represents an additional 13,000 MW that kick in just as the sun sets. CAISO sees three significant risks to system integrity arising from the duck curve:

Ramping: Accelerated up and down ramping requires variable resources with quick on and off times.

Overgeneration: In the middle of the day, when the sun shines and the wind blows, renewables will feed into the grid, posing a challenge to grid integrity.

Frequency regulation: Difficulty in operating and adjusting to maintain constant frequency (e.g., 60 hertz in CAISO).

In order to mitigate the risks above, CAISO and other energy players (including the three big investor-owned utilities and the California Public Utilities Commission) have been pushing an array of products and technology initiatives, including the following:

Flexible Ramping Product: This product will allow CAISO to procure ramping capacity through a special 15-minute interval market. The product was initially requested by the CAISO board in April 2011 and is still in stakeholder discussions.[18]

Distributed Energy Resources: Distributed energy resources with smart metering, small-scale storage (including with electric vehicles), rooftop solar and energy response will need to be integrated in a distributed, managed system.

[18] http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

Gas as a Solution

Gas-fired power plants are suited to address the needs of energy markets in the age of the duck curve. With cold start times of under 10 minutes, spinning reserves, automatic frequency regulation and other ancillary services, gas plants can ramp up and down quickly to meet variable response and supply. Paired with a predicted long-term trend in low gas prices and, particularly in California, scarce hydro, gas-fired power plants may have a bright future in solar-dominated California, although gas, as a fossil fuel, does not quite fit into the renewable mandate.

Challenges Faced by Gas-Fired Plant Owners and Operators

All is not rosy, however, for gas-fired plant owners and operators. The particular characteristics of the duck curve do pose significant challenges. On the technical side, the rapid ramp-up and ramp-down and frequent stops mean that existing plants are not necessarily operating as designed, i.e., at full load or as a baseload plant. Combined cycle plants, fitted out with boilers cogenerating electricity from waste heat, are not designed to operate as peakers for two to three hours a day, which is what the duck curve would seem to require. The increased number of starts and stops may well lead to higher maintenance costs and a shorter useful life for gas turbines.

Commercially, the duck curve poses a number of interesting challenges to gas plant owners and operators and their lenders. Most gas plant owners prefer long-term, fixed-price power purchase agreements with reliable offtake parties, partly in order to finance construction. The greater volatility in short-term trading markets effectively means that the lenders are more likely to favor shorter tenors and greater equity commitments. Furthermore, there is considerable uncertainty as to what the duck curve will actually look like, as there are a number of variables at play, including demand response, advanced inverters, export markets and purchases from neighboring ISOs (which will be going through their own duck curve transformations), improved storage technology, etc. All of these factors may well help to “flatten” the duck curve.

Clean Power Plan Breathes New Life into Carbon Reduction Efforts

by Jeff Salinger

On August 3, 2015, President Obama announced the publication of the Clean Power Plan (CPP), which EPA promulgated pursuant to Section 111(d) of the Clean Air Act. The CPP represents the first-ever national standards to address CO2 pollution from existing power plants.[19]

Under the plan, EPA is establishing interim and final state-wide goals for CO2 emissions from affected power plants. EPA's CPP assigns each state an emissions rate goal, in pounds of carbon dioxide (CO2) per megawatt hour (MWh), but also gives states an option to translate this goal into a mass-based goal, in pounds of CO2.

The CPP is expected to sharply reduce carbon pollution by shifting our electric power system toward cleaner energy sources at a steady and predictable pace. Enforceable CO2 limits will commence in 2022 and be in full effect by 2030.

Overview

The plan establishes uniform national CO2 emission performance rates (measured in pounds of CO2 per MWh of electricity generation) for certain types of electric-generating utilities (EGUs) that were in operation, or had commenced construction, as of January 8, 2014. Affected EGUs include fossil fuel-fired electric steam-generating units, such as oil, natural gas or coal units, and stationary combustion turbines, including natural gas combined cycle units.

In most cases, states will rely on a variety of measures. CPP-supported options consist primarily of (i) shifting to cleaner energy; (ii) promoting the use of renewable energy sources; (iii) improving the emissions performance of existing facilities; and (iv) adopting or promoting energy efficiency measures to reduce overall energy demand.

The CPP encourages states to develop customized plans to ensure that affected power plants meet both interim (during the 2022-2029 time frame) and final CO2 emissions performance rates (in 2030). States have up to three years to write implementation plans, applying their knowledge of their utilities and the programs that have worked in the past. Participating states will be required to submit to EPA either an initial plan with a request for an extension, or a final

[19] Under the Supreme Court decision in *Massachusetts v. EPA*, greenhouse gases meet the definition of air pollutants under the Clean Air Act. Under the CAA, air pollutants must be regulated if they could be reasonably anticipated to endanger public health or welfare. EPA made this determination in 2009. In June 2013, President Obama directed EPA to work closely with states, power plant operators and other stakeholders in developing carbon standards for existing power plants. EPA released its proposed rule in June 2014 and the final rule in August 2015.

“approvable” plan by September 6, 2016. EPA may grant extensions of up to two years, until September 6, 2018. If EPA grants an extension, the state must submit a progress report by September 6, 2017. States may submit individual plans or multi-state plans, as described in greater detail below. A “Federal Implementation Plan” will be finalized for any state (with covered EGUs) that EPA determines has not submitted an approved Section 111(d) plan by the designated compliance date.

Two Approaches

The CPP provides guidelines for the development and implementation of state plans to achieve interim and final CO2 emissions rates for EGUs. States can choose between two types of plans: an “emissions standards” approach or a “state measures” approach. An emissions standards approach imposes federally determined standards directly on affected EGUs. In contrast, a state measures approach allows states to achieve state-wide, rather than facility-specific, emissions reductions.

The emission standards approach will measure emissions in pounds of CO2 emissions per megawatt-hour (MWh) of electricity generation. This approach includes source-specific requirements.[20] If a state chooses the emission standards approach, it would implement specified emission rate standards for all affected EGUs in the state. This approach could involve multiple states and allows for the creation of an emission-rate trading system.

A state measures approach allows a state to achieve the equivalent of the CO2 emission standards approach by using some combination of federally enforceable standards for EGUs and elements that would be enforceable only under state laws. Examples of such elements include renewable energy and/or energy efficiency requirements that could be applied to affected EGUs or other entities. States opting for this approach will be required to use a mass-based target to ensure that the proposed state measures achieve overall emission reductions. Options for cutting emissions include investing in renewable energy, energy efficiency, natural gas and nuclear power, and shifting away from coal-fired power.

The CPP paves the way for states to design compliance strategies that are “trading ready,” and gives states the option to work with other states in multi-state approaches to reduce emissions, including via regional emissions trading platforms or exchanges. As a result, out-of-state ERCs or allowances would likely be used by states and regulated EGUs to meet emission reduction requirements. This component of the plan also incentivizes the development of cost-effective renewable energy resources, since regional trading programs would reward clean-burning power sources by providing credits that could be sold to heavy polluters to offset CO2 emissions.

Clean Energy Incentive Program

As part of the CPP, EPA created incentives for future development of renewable energy projects. Specifically, the CPP established the Clean Energy Incentive Program (CEIP), which is expected to be a preferred option for states considering compliance strategies. The CEIP begins on January 1, 2020 and runs throughout 2020 and 2021. States that have expressed interest in participating in this program in their final plans are eligible.

[20] EPA uses the state-specific emission rate targets to calculate equivalent state-specific mass-based targets, measured in metric tons of CO2.

According to EPA, the CEIP is designed “to reward early investments in renewable energy generation and demand-side energy efficiency measures.” A corollary environmental benefit is to limit the growth of natural gas, especially in light of the new CO2 emission limits established by the CPP. Under the CPP, states that invest in wind and solar projects that commence construction after a state’s compliance plan is finalized (to help meet their emission reduction targets) will generate credits for renewable energy generation in the years 2020 and 2021, ahead of the CPP’s 2022 start date. Energy efficiency investments in low-income communities are also incentivized by the CEIP.

Participation in the CEIP is optional. States that act early to cut CO2 pollution, either with renewables or energy efficiency, would be rewarded with emission reduction credits, which they could use to meet their targets or sell to other emitters.

The CEIP sets up a system to award credits to energy efficiency projects in low-income communities and renewable energy projects (only wind and solar) in participating states. The credits are in the form of emission rate credits or emission allowances, depending on whether a state uses an emission rate or mass-based target, respectively. The credits could be sold to or used by an affected emission source to comply with the state-specific requirements. Under the CPP, renewable energy projects would receive one credit (either an allowance or ERC) from the state and one credit from EPA for every two megawatt-hours (MWh) of solar or wind generation. Energy efficiency projects in low-income communities would receive double credits ─ for every two MWh of avoided electricity generation, energy efficiency projects will receive two credits from the state and two credits from EPA.

EPA will match up to 300 million short tons in credits during the CEIP program life. The amount of EPA credits potentially available to each participating state depends on the amount of emission reduction each state is required to achieve compared to its 2012 baseline. As a result, states with greater reduction requirements will have access to a greater share of the EPA credits.

Looking Ahead

A range of legal and legislative challenges await the CPP in 2016, as well as more limited financing options for coal operators. In addition, and as discussed above, initial state plans with requests for an extension or final plans must be submitted to EPA by September 6, 2016.

As of the date of this publication, the Republican Congress has passed bills in both houses of Congress to invalidate the CPP. On December 1, the House of Representatives passed a resolution, previously passed by the Senate, to repeal the CPP. The resolutions would both nullify the CPP and prevent “substantially similar” rules from being introduced in the future. These resolutions, however, are expected to be vetoed by President Obama. It is unlikely that opponents of the CPP will be able to mobilize the votes needed to override a presidential veto in 2016.

Similarly, utility and industry groups, including the coal industry, have commenced legal challenges against the CPP. In addition, a group of 24 states, led by West Virginia, Oklahoma and North Dakota, have also challenged the rule. These challenges allege, among other items, that EPA lacks the authority under the Clean Air Act to mandate carbon emission cuts from EGUs and that EPA is prohibited from issuing rules under Section 111(d) of the Clean Air Act because EGUs are already regulated under Section 112. It is likely that some of these challenges will be heard by the US Supreme Court.

In late November, Morgan Stanley and Wells Fargo announced plans to reduce involvement in, and funding for, coal projects. Morgan Stanley’s “Coal Policy Statement” includes a commitment to decline financing transactions that “directly support the development of new or physical expansions of coal-fired power generation, unless there is sufficient carbon capture and storage equivalent emissions and pollutant reduction technology in place." Morgan Stanley has also committed to "continue to reduce [its] exposure to coal mining globally" and not to provide financing where the "specified use of proceeds would be directed towards" mountaintop removal mining. It also indicated that it would not provide financing to any company that does not have a plan to eliminate existing mountaintop removal operations in the foreseeable future.

Wells Fargo's Environmental and Social Risk Management policy commits the bank to "limit and reduce [its] credit exposure to the coal mining industry." In response to concerns about mountaintop removal mining, Wells Fargo's policy states that its involvement with mountaintop removal mining "is limited and declining."

Conclusion

The CPP is a Clean Air Act initiative to cut CO_2 emissions from certain power plants and to spur the development and growth of renewable energy. At its core, it reflects the first uniform effort to reduce CO_2 emissions from existing fossil fuel-fired power plants. Under the CPP, states may choose to meet specified CO_2 emissions reduction targets or opt to join together in multi-state or regional compacts to find the lowest cost options for reducing CO_2 emissions, including via emissions trading programs. No matter the choice, one thing appears clear: CO_2 emissions from fossil fuel-fired power plants appear to be on track to decrease significantly by 2022 and are projected to be 32 percent below 2005 emissions levels by 2030.

Additional LNG/CNG Export Projects Get the Green Light

by Donna J. Bobbish

In 2015, the United States Department of Energy's Office of Fossil Energy (DOE/FE) authorized the long-term, large-scale export of US-produced liquefied natural gas (LNG) for four export projects with a cumulative volume of exports totaling some 4.26 billion cubic feet per day (Bcf/d) of natural gas. DOE/FE issued the export authorizations after the Federal Energy Regulatory Commission (FERC) had authorized the construction of facilities to be used for the export of LNG. These approved LNG export projects are Dominion Cove Point LNG, LP (0.77 Bcf/d),[21] Cheniere Marketing, LLC and Corpus Christi Liquefaction, LLC (2.1 Bcf/d),[22] Sabine Pass Liquefaction, LLC Expansion Project (1.38 Bcf/d),[23]and American LNG Marketing LLC (0.008 Bcf/d).[24]

In 2012 and 2014, FERC authorized the construction of LNG export facilities and DOE/FE authorized the long-term, large-scale export of LNG for four LNG export projects with a cumulative volume of exports totaling 5.74 Bcf/d of natural

21 *Dominion Cove Point LNG, LP*, DOE/FE Order No. 3331-A, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas from the Cove Point LNG Terminal in Calvert County, Maryland, to Non-Free Trade Agreement Nations (May 7, 2015), *reh'g pending*; and *Dominion Cove Point LNG, LP*, Order Granting Section 3 and Section 7 Authorizations, 148 FERC ¶ 61,244 (Sept. 29, 2014), *reh'g denied*, 151 FERC ¶ 61,095 (May 4, 2015), *petition for review pending*.

22 *Cheniere Marketing, LLC and Corpus Christi Liquefaction, LLC*, DOE/FE Order No. 3638, Final Order and Opinion Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Proposed Corpus Christi Liquefaction Project to Be Located in Corpus Christi, Texas, to Non-Free Trade Agreement Nations (May 12, 2015), *reh'g pending*; and *Corpus Christi Liquefaction, LLC, et al.,* Order Granting Authorization Under Section 3 of the Natural Gas Act and Issuing Certificates, 149 FERC ¶ 61,283 (Dec. 30, 2014), *reh'g denied*, 151 FERC ¶ 61,098 (May 6, 2015), *petition for review pending*.

23 *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 3669, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Sabine Pass LNG Terminal Located in Cameron Parish, Louisiana, to Free Trade Agreement Nations (June 26, 2015); and *Sabine Pass Liquefaction Expansion, LLC, et al.*, Order Granting Authorization Under Section 3 of the Natural Gas Act and Issuing Certificates, 151 FERC ¶ 61,012 (Apr. 6, 2015), *reh'g denied*, 151 FERC ¶ 61,253 (June 23, 2015).

24 *American LNG Marketing LLC*, DOE/FE Order No. 3690, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas in ISO Containers Loaded at the proposed Hialeah Facility near Medley, Florida, and Exported by Vessel to Non-Free Trade Agreement Nations (Aug. 7, 2015). FERC did not authorize the construction of the Hialeah Facility.

gas. These projects are Sabine Pass Liquefaction, LLC (2.2 Bcf/d),[25] Carib Energy (USA) LLC (0.04 Bcf/d),[26] Cameron LNG, LLC (1.7 Bcf/d),[27] Freeport LNG Expansion, L.P. (1.4 Bcf/d),[28] and Freeport LNG Expansion L.P. (0.4 Bcf/d).[29]

Also, in October, DOE/FE authorized Emera CNG, LLC to export compressed natural gas (CNG) by waterborne vessels to non-FTA countries up to the equivalent of 0.008 Bcf/d of natural gas for a 20-year term.[30] FERC had determined in 2014 that Emera's proposed facilities and operations would not be subject to FERC's jurisdiction under the Natural Gas Act (NGA).[31] This approval raised the total volume of authorized long-term, large-scale LNG and CNG exports to just over 10 Bcf/d.

Section 3 of the NGA gives FERC exclusive jurisdiction to approve the construction and operation of LNG Terminals, which include natural gas facilities located onshore or in state waters used to receive, unload, load, store, transport, gasify, liquefy or process natural gas that is exported to a foreign country from the US. FERC approves the siting, construction and operation of LNG terminals upon a finding that such activities are not inconsistent with the public interest.

Section 3 of the NGA also gives DOE/FE authority over exports of natural gas. Under Section 3(c) of the NGA, LNG exports to countries with which the US has free trade agreements that require "national treatment" for trade in natural gas are automatically considered in the public interest. Requiring "national treatment" means treating an imported good the

25 *Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P.,* Order Granting Section 3 Authorization, 139 FERC ¶ 61,039 (2012), *reh'g denied*, 140 FERC ¶ 61,076 (2012); and Sabine Pass Liquefaction, LLC, DOE/FE Order No. 2961-A, Final Opinion and Order Granting Long-Term Authorization to Export Liquefied Natural Gas From Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations (Aug. 7, 2012), *reh'g dismissed*.

26 *Floridian Natural Gas Storage Company, LLC*, Order Amending Certificate, 140 FERC ¶ 61,167 (2012); and *Carib Energy (USA) LLC*, DOE/FE Order No. 3487, Final Order Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural gas in ISO Containers by Vessel to Non-Free Trade Agreement Nations in Central America, South America or the Caribbean (Sept. 10, 2014).

27 *Cameron LNG, LLC, et al.,* Order Granting Authorization Under Section 3 of the Natural Gas Act and Issuing Certificates, 147 FERC ¶ 61,230 (June 19, 2014), *Cameron LNG, LLC, et al.,* 148 FERC ¶ 61,073 (July 29, 2014) (Notice Rejecting Request for Rehearing and Dismissing Request for Stay); and *Cameron LNG, LLC*, DOE/FE Order No. 3391-A, Final Opinion and Order Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Cameron LNG Terminal in Cameron Parish, Louisiana, to Non-Free Trade Agreement Nations (Sept. 10, 2014), *reh'g denied*.

28 *Freeport LNG Development, L.P., et al.,* Order Granting Authorizations Under Section 3 of the Natural Gas Act, 148 FERC ¶ 61,076 (July 30, 2014); *reh'g denied*, 149 FERC ¶ 61,119 (Nov. 13, 2014), petition for review pending, and *Freeport LNG Expansion, L.P., et al.,* DOE/FE Order No. 3282-C, Final Opinion and Order Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Freeport LNG Terminal on Quintana Island, Texas, to Non-Free Trade Agreement Nations (Nov. 14, 2014).

29 *Freeport LNG Expansion, L.P., et al.,* DOE/FE Order No. 3357-B, Final Opinion and Order Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Freeport LNG Terminal on Quintana Island, Texas, to Non-Free Trade Agreement Nations (Nov. 14, 2014).

30 *Emera CNG, LLC*, DOE/FE Order No. 3727, Final Opinion and Order Granting Long-Term, Multi-Contract Authorization to Export Compressed Natural Gas by Vessel From a Proposed CNG Compression and Loading Facility at the Port of Palm Beach, Florida, to Non-Free Trade Agreement Nations (Oct. 19, 2015).

31 *Emera CNG, LLC*, Order on Petition for Declaratory Order, FERC Docket No. CP14-114-000, 148 FERC ¶ 61,219 (Sept. 19, 2014).

same as a locally produced good once it enters a market. Applications to export gas to such countries must be approved without modification or delay. The US currently has such free trade agreements with Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, Republic of Korea and Singapore.

Authorization to export LNG to countries without such free trade agreements requires DOE/FE to find that the proposed exports are not inconsistent with the public interest. In making this determination, DOE considers the domestic need for the natural gas proposed to be exported, whether the proposed exports pose a threat to the security of domestic natural gas supplies and other factors bearing on the public interest. DOE also must review the potential environmental effects of the proposed export under the National Environmental Policy Act.

In 2011, DOE/FE engaged the US Energy Information Administration (EIA) and NERA Economic Consulting (NERA) to conduct a two-part study of the economic impacts of LNG exports. The two studies were published in 2012.[32] EIA examined the impact of two DOE/FE prescribed levels of assumed natural gas exports (at 6 Bcf/d and 12 Bcf/d) under numerous scenarios which included a variety of supply, demand and price outlooks. EIA generally found that LNG exports will lead to higher domestic natural gas prices, increased domestic natural gas production, reduced domestic natural gas consumption and increased natural gas imports from Canada via pipeline. The NERA study analyzed the potential macroeconomic impacts of LNG exports under a range of global natural gas supply and demand scenarios, including scenarios with unlimited LNG exports. For every market scenario examined, NERA found that net economic benefits to the US increased as the level of LNG exports increased.

According to DOE/FE, the total approved export volume of 10.01 Bcf/d of natural gas for the 10 final export authorizations issued from 2012 through 2015 is within the range of scenarios analyzed in the EIA and NERA studies, in which NERA found that in all such scenarios—assuming either 6 Bcf/d or 12 Bcf/d of export volumes—the US would experience net economic benefits.

It is expected that during the first quarter of 2016, FERC and DOE will issue final authorizations for the construction of LNG export facilities and long-term, large-scale exports of LNG for Jordan Cove Energy Project LP (2.0 Bcf/d)[33] and Magnolia LNG, LLC (1.08 Bcf/d).[34] FERC issued final Environmental Impact Statements for both projects in the third quarter of 2015, and DOE/FE had granted Jordan Cove conditional authorization to export LNG to non-FTA countries in 2014.

32 EIA published its study, *Effect of Increased Natural Gas Exports on Domestic Energy Markets*, in January 2012. DOE published the NERA Study, *Macroeconomic Impacts of LNG Exports from the United States*, in December 2012.

33 *See* FERC Docket No. CP13-483-000 and FE Docket No. 12-32-LNG

34 *See* FERC Docket No. CP14-347-000 and FE Docket No. 13-132-LNG.

PJM Restructures Its Capacity Market Design

by Donna J. Bobbish

In 2015, PJM Interconnection, L.L.C. (PJM), the regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia, began implementing significant reforms to its capacity market construct, as well as corresponding changes to its energy markets. These actions were taken to ensure that committed capacity resources will perform when called upon to meet the reliability needs of the PJM region. Since 2007, PJM's capacity market construct, the Reliability Pricing Model (RPM), has utilized a three-year forward capacity market to ensure resource adequacy at a reasonable cost through the use of an annual auction, the "Base Residual Auction," and subsequent Incremental Auctions closer to the delivery year.

In filings made with the Federal Energy Regulatory Commission (FERC) in December 2014, PJM argued that its capacity market design has failed to keep pace with the level of resource commitments required, has not adequately ensured actual performance and has failed to provide adequate incentives for resource performance. PJM argued that these flaws can threaten the reliable operation of the PJM system and force consumers to pay for capacity without receiving commensurate reliability benefits.

In order to address these problems, PJM proposed a new capacity product, the "Capacity Performance Resource," to provide greater assurance of the delivery of energy and reserves during emergency conditions. PJM further proposed charges for poor performance, credits for superior performance and a must-offer requirement for Capacity Performance Resources.

In June 2015, FERC generally approved PJM's proposed market reforms, finding that PJM had demonstrated the need for reforms to ensure the long-term reliability of electric supply in the PJM region.[35] FERC's order on PJM's market reform proposal came a year after it approved similar reforms of the ISO New England Inc. Forward Capacity Market design.[36]

PJM will procure all of the region's capacity requirements in the form of Capacity Performance Resources beginning with the 2020-21 delivery year. As a transition to the Capacity Performance Resource product, PJM established a separate, interim capacity product with a lower performance expectation, a "Base Capacity Resource," for the 2018-19 and 2019-20 delivery years. For those delivery years, PJM intends to procure at least 80 percent of the region's capacity requirement in the form of Capacity Performance Resources, with the remainder composed of Base Capacity Resources. For delivery years 2016-17 and 2017-18, for which the Base Residual Auction has already been conducted, PJM will procure a portion of Capacity Performance Resources through two Transition Auctions.

[35] *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,208 (2015), *reh'g pending* (the "June 9 Order").

[36] *ISO New England Inc.*, 147 FERC ¶ 61,172 (2014), *reh'g denied*, 153 FERC ¶ 61,223 (2015).

In light of the D.C. Circuit Court of Appeals' decision in 2014 vacating FERC's final rule on demand response compensation in wholesale energy markets,[37] PJM's proposal, as approved by FERC in the June 9 Order, did not permit demand response and other non-generation resources to participate in the Transition Auctions. In an order issued on July 22, 2015, FERC granted a request for rehearing of that aspect of the June 9 Order, finding that such exclusion is unjust, unreasonable and unduly discriminatory, and requiring PJM to allow non-generation resources to participate in the Transaction Auctions if they are technically capable of providing the capacity service to be procured through those auctions.[38]

Capacity Performance Resource

PJM has replaced its existing capacity products with the new Capacity Performance Resource. The Capacity Performance Resource must be capable of sustained, predictable operation that allows the resource to be available to provide energy and reserves whenever PJM determines an emergency condition exists, but is not required to operate during all hours of a delivery year.

All annual Capacity Resources will be eligible to offer as Capacity Performance Resources unless they qualify for an exemption from PJM's must-offer requirement. In order to offer as a Capacity Performance Resource, an External Generation Capacity Resource must demonstrate that it meets, or will meet by the start of the delivery year, the criteria for an exception to the Capacity Import Limit.

Capacity Storage Resources, Intermittent Resources, Energy Efficiency Resources and Demand Resources are permitted to submit stand-alone Capacity Performance sell offers in a megawatt (MW) quantity consistent with their average expected output during peak-hour periods. In addition, Demand Resources, Energy Efficiency Resources, Capacity Storage Resources, Intermittent Resources and Environmentally-Limited Resources (defined as a resource which has a limit on its run hours imposed by a federal, state or other governmental agency that will significantly limit its availability on either a temporary or long-term basis) may submit aggregated offers as a Capacity Performance Resource. Aggregated resources may either be owned by or under contract to the seller submitting the offer, including resources obtained through bilateral contract and reported to PJM through its capacity accounting system.

PJM also established, on a phased-in-basis, an Annual Demand Resource product to replace its existing demand response capacity products and requires that Annual Demand Resources conform with the standards applicable to a Capacity Performance Resource. Annual Demand Resources are permitted to aggregate with other eligible resource types to submit a Capacity Performance offer.

Instead of delineating specific eligibility requirements for a Capacity Performance Resource, PJM's proposal to FERC had included a requirement that a market seller submitting a Capacity Performance offer make a good faith representation that (i) it has made, or will make, the necessary investment to ensure that its resource has the capability to provide energy when

[37] *EPSA v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *cert. granted*, Nos. 14-840 and 14-841.

[38] *PJM Interconnection, L.L.C., et al.*, 152 FERC ¶ 61,064 (2015), *reh'g pending* (the "July 22 Order").

called upon; (ii) the resource meets the operational requirements and performance obligations applicable to Capacity Performance Resources; and (iii) the seller's offer contemplates the physical delivery of the Capacity Performance Resource no later than the commencement of the applicable delivery year. Fossil-fueled generation resources would be required to make an additional good faith representation that they have obtained and hold, or reasonably expect to obtain and hold, the contractual and other rights necessary to ensure firm fuel supply to each of their affected units during the delivery year. FERC, however, rejected PJM's proposed good-faith representation requirement, finding it to be inappropriately vague, and could cause well-performing resources to elect not to participate in the capacity market to avoid the risk of sanctions. Among other things, FERC noted that PJM will be authorized to review Capacity Performance Resource sell offers in order to mitigate speculative participation in PJM's capacity market.

PJM also revised its milestone requirements to obligate a planned generation resource to execute a Facilities Study Agreement in order to submit an offer into PJM's Base Residual Auction.

Under its revised market design, PJM, in consultation with the Market Monitor, has discretion to reject a sell offer if it determines that the relevant resource does not qualify as a Capacity Resource; that is, if the resource cannot reasonably be relied on to perform, as required, during emergency conditions, is purely speculative or would otherwise undermine the intent of PJM's Capacity Performance construct. However, PJM may only reject an offer when a resource fails to demonstrate that it can reasonably be expected to meet Capacity Performance obligations, consistent with the resource's offer, by the relevant delivery year.

On an interim basis, PJM will reclassify its existing capacity market product as a Base Capacity product. Base Capacity Resources will include internal and external capacity resources; Intermittent Resources; Capacity Storage Resources; Annual Demand Resources; Base Capacity Demand Resources; and Base Capacity Efficiency Resources. Base Capacity Resources will be permitted to participate in PJM's capacity auctions in the 2018-19 and 2019-20 delivery years. Summer-only resources seeking to submit offers as Base Capacity Resources must demonstrate that they are, or will be, physically incapable of meeting the year-round performance expected of a Capacity Performance Resource.

Market Mitigation

Beginning with the 2018-19 delivery year, the installed capacity of every Generation Capacity Resource located in the PJM region that is capable, or that reasonably can become capable, of qualifying as a Capacity Performance Resource must be offered as a Capacity Performance Resource, subject to applicable demand-equivalent forced outage rate (EFORd) and Unforced Capacity determinations, and an exceptions process.

PJM has revised its market power mitigation rules to allow for sell offers that will cover the seller's expected new costs of improving their resources' performance, and the perceived risks of non-performance. In its December 2014 filing with FERC, PJM had proposed a default offer cap for Capacity Performance Resources equal to Net Cost of New Entry (Net CONE). PJM subsequently amended its proposal to provide for a default offer cap set at the product of Net CONE times the average of the Balancing Ratios in the three consecutive calendar years that precede the Base Residual Auction for the delivery year. PJM also will allow resources with high avoidable costs to submit unit-specific offer caps that detail all Avoidable Cost Rate components, including a quantifiable risk premium. A Market Seller Offer Cap may, at the election of the seller, exceed the Net CONE default offer cap, subject to an Avoidable Cost Rate that will permit the costs of natural gas transportation, other gas service and a risk premium. FERC approved PJM's amended proposal, finding that "[a]ny Capacity Performance offer below the default offer cap can properly be deemed competitive, and any offer above that level will be scrutinized by the Market Monitor and PJM to ensure that it is based on legitimate costs and reasonable estimates of unit-specific performance and system parameters."

Non-Performance Charges

PJM established a new Non-Performance Charge, applicable to Capacity Performance Resources, which is based on the expected performance of each Capacity Resource, as compared to its actual performance during an Emergency Action declared by PJM. Emergency Actions are defined as locational or system-wide capacity shortages, including Voltage Reduction Warnings, Manual Load Dump Warnings, Voltage Reduction Actions and Manual Load Dump Actions, that cause pre-emergency mandatory load management reductions or a more severe action. PJM will measure Capacity Resources' performance during Performance Assessment Hours, which will be triggered when PJM declares an Emergency Action. The measure of expected performance and actual performance will differ based on the resource type at issue and PJM's existing rules governing those resources. If a Capacity Resource's actual performance falls short of its expected performance, its shortfall will be subject to the Non-Performance Charge, absent a valid excuse or the application of a stop-loss limit.

Capacity Performance Resources will be subject to Non-Performance Charges, but will not also be subject to PJM's Peak Season Maintenance Compliance Charge or Peak-Hour Period Availability Charge. Base Capacity Resources will be subject to a Non-Performance Charge if they fail to perform under emergency conditions during the months of June through September.

PJM will base the Non-Performance Charge rate on Net CONE divided by 30, the assumed number of Emergency Action hours per year.

PJM also established "stop-loss" limits on the total Non-Performance Charges it may assess. In the June 9 Order, FERC accepted PJM's proposed annual Non-Performance Charge stop-loss limit equal to 1.5 times annual Net CONE, but conditioned its acceptance on the elimination of PJM's proposed monthly stop-loss limit equal to 0.5 times annual Net CONE.

A Capacity Resource will be not be assessed Non-Performance Charges if it was not scheduled by PJM because it was on an approved planned or maintenance outage, or was scheduled down based on PJM's determination that such scheduling action was appropriate to the security-constrained economic dispatch of the PJM region. A Capacity Resource will be assessed Non-Performance Charges if it otherwise would have been scheduled by PJM's Office of Interconnection to perform, but was not scheduled to operate, or was scheduled down, solely due to any operating parameter limitation submitted in the resource's offer, or the seller's submission of a market-based offer higher than its cost-based offer.

PJM also has revised its tariff to limit the circumstances under which market participants are excused from performing their obligations. Beginning with the 2018-19 delivery year, an event classified by the North American Electric Reliability Corporation (NERC) as "outside management control" will be treated as a forced outage for the purpose of calculating a forced outage rate or peak-hour period penalties.

Performance Bonus Payments

Revenue collected by PJM from payment of Non-Performance Charges will be distributed, as a bonus, to resources that perform above expectations, based on the ratio of the relevant resource's bonus performance level to the total bonus performance from all resources over the same Performance Assessment Hour. Specifically, PJM will distribute Non-Performance Credits for a Performance Assessment Hour to each Market Participant—whether or not such Market Participant committed capacity for that hour—that provided energy or load reductions above the levels expected for such resource during such hour. Unlike the approach taken by ISO-NE, PJM's mechanism will assess performance during Emergency Actions rather than only during shortage or scarcity conditions.

Financial Security Requirements

Previously, PJM's tariff required that sellers of certain Capacity Resources provide credit support prior to an RPM Auction equal to the product of the MW to be offered times an RPM Auction Credit Rate determined using Net CONE for the relevant delivery year. PJM has revised the Auction Credit Rate for sellers submitting offers for a Capacity Performance Resource to be the greater of (i) 0.5 times the Net CONE for the relevant delivery year or (ii) $20/MW-day times the number of days in that delivery year.

For the period following the posting of the Based Residual Auction Result, the Auction Credit Rate for Capacity Performance Resources will be the number of days in the delivery year times the greater of (i) $20/MW-day; or (ii) 0.2 times the capacity resource clearing price (MW-day); or (iii) the lesser of 0.5 times Net CONE or 1.5 times Net CONE minus the applicable capacity resource clearing price for the resource (MW-day).

Following posting of the Base Residual Action results, planned resources that cleared the Capacity Performance Auction are required to provide credit support equal to the greater of (i) 0.2 times the Base Residual Auction Clearing price for the Locational Deliverability Area within which the resource is located; (ii) $20/MW-day; and (iii) the lesser of (a) 0.5 times Net CONE and (b) 1.5 times Net CONE minus the Base Residual Auction clearing price for the Locational Deliverability Area within which the resource is located.

For a seller seeking to offer in an Incremental Auction a Capacity Performance Resource that has not been committed previously for a delivery year, the Auction Credit Rate will be the greater of (i) 0.5 times Net CONE or (ii) $20/MW-day, times the number of days in such delivery year. The Auction Credit Rate for Capacity Performance Resources committed in the Incremental Auction will be the number of days in that delivery year times the greater of (i) 0.2 times the Incremental Auction clearing price for the relevant delivery year of $20/MW-day, or (ii) the lesser of 0.5 times the Net CONE for the relevant delivery year, or 1.5 times Net CONE for the relevant delivery year minus the Incremental Auction Clear Price.

Sellers of Planned Generation Capacity Resources may incrementally reduce their credit obligations after achieving certain project development milestones and the project moves toward being placed in-service. In addition, the initial RPM Credit Requirement for resources that have secured financing or had full funding available prior to the start of the 2015 Base Residual Auction is equal to half the product of the RPM Auction Credit Rate times the MW offered and may be further reduced upon achieving certain project development milestones.

Energy Market Revisions

Operating Parameters

PJM also revised its energy market rules to require market-based offers for Capacity Resources to be based on the specific physical characteristics of that resource, rather than on economic and budgetary considerations, under circumstances that would typically precede an emergency event (known as "parameter limited"). If a resource cannot actually be operated within these more flexible parameters, then it must inform PJM of the parameters to which it is capable of being operated. PJM's Office of Interconnection will determine the unit-specific achievable operating parameters for each individual resource on the basis of its operating design characteristics and other constraints, including the actual operational limitations of the relevant resource type. These unit-specific values will apply for the generation resource unless it is operating pursuant to an exception from those values meeting the minimum parameters.

Resources may recover, through make-whole payments, the costs incurred if a resource operates within its actual constraints and not only within its unit-specific parameter limits based on its physical characteristics. A resource would only be deemed ineligible for make-whole payments if it operates outside any actual constraints faced by the resource, not only limitations based on the resource's physical constraints. A resource that operates outside of its unit-specific parameter limits can seek to justify such operation to PJM as the result of actual constraints, rather than the exercise of market power. If the resource provides adequate justification, it would be eligible for any appropriate make-whole payments for that operating interval.

PJM also established a standardized start-up and notification time of 24 hours or less for Capacity Performance Resources bidding into PJM's energy markets, absent the issuance of a hot or cold weather alert. When a weather alert has been issued, the combined notice and start-up time would not be permitted to exceed 14 hours.

Force Majeure

PJM revised its Operating Agreement to include a new defined term, "Catastrophic Force Majeure," which includes only actions or events in which there has been a systematic failure in all or substantially all of the PJM areas of either the transmission system or the fuel delivery network. It also narrowed its existing force majeure provisions, as applicable to all market transactions, to apply only in the event of a Catastrophic Force Majeure. Performance of any obligation arising under the Operating Agreement will not be excused or suspended because of an event of force majeure, unless the event constitutes an event of Catastrophic Force Majeure, and that event of Catastrophic Force Majeure was not caused by the member's fault or negligence. PJM's broader, existing force majeure protections will continue to apply to non-market, bilateral arrangements, such as interconnection service agreements.

Generator Outages

PJM has revised its energy market rules to prohibit a Generator Maintenance Outage from proceeding unless it has been submitted to PJM for approval and has been approved prior to the outage start date. PJM may withhold approval, or withdraw a prior approval, to "ensure adequacy of reserves or the reliability of the PJM Region in connection with anticipated implementation or avoidance of Emergency procedures." PJM must give notice to the seller at least 72 hours prior to requiring the generator to return to normal operation. If PJM withholds, withdraws or rescinds approval for an outage, it will work with the seller to reschedule the outage at the earliest practicable time.

With respect to Generator Planned Outages, PJM revised its rules to require a seller seeking approval for such an outage to provide PJM with an estimate of the amount of time it needs to return to service. PJM will use this information to facilitate a voluntary solution should emergency conditions approach, or arise, that may need to return the resource to service.

Maximum Emergency Offers

PJM has revised its tariff to clarify the day-ahead energy market obligation for Generation Capacity Resources. Any capacity that is designated by a Generation Capacity Resource as a Maximum Emergency Offer and not dispatched by PJM because of its use of a Maximum Emergency Offer should be considered non-performing for purposes of applying Non-Performance Charges.

Status of Approval of PJM's Market Restructuring

FERC's June 9 and July 22 Orders are subject to rehearing and, potentially, judicial review. In July and October 2015, PJM made filings in compliance with FERC's June 9 and July 22 Orders, which filings currently are pending review by FERC.

In December 2015, PJM made an informational filing to inform FERC that for the 2016-2017 delivery year, which commences on June 1, 2016, PJM plans to implement its Capacity Performance rules as accepted by FERC and clarified in PJM's compliance filings. In order to allow PJM to make any necessary adjustments prior to June 1, PJM asked FERC to issue an order addressing the pending requests for rehearing of the June 9 and July 22 Orders as well as PJM's compliance filings by February 1.

Transition Auctions

In 2015, PJM conducted two Transition Auctions under its new capacity market requirements. The first, held August 26-27, procured 95,096.6 megawatts of resources at $134 per megawatt-day for 60 percent of capacity needs for the 2016-2017 delivery year.[39] The second Transition Auction, held September 3-4 to procure Capacity Performance resources for 70 percent of capacity needs for the 2017-2018 delivery year, procured 112,195 megawatts of power resources at $151.50 per megawatt-day, below the offer cap.[40]

[39] PJM News Release, "PJM Capacity Performance Transitional Auction Ensures Availability of Resource to Maintain Reliable Power Supplies for 2016-2017," Aug. 31, 2015.

[40] PJM News Release, "Second PJM Capacity Performance Transitional Auction Ensures Power Supplies for 2107-2018," Sept. 9, 2015.

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