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Energy Highlights

- The EPA issued final rules establishing national air pollution regulations for hydraulic fracturing, the process by which much of the recent wellspring of shale gas is extracted in the United States. The new rules do not cover such issues as groundwater contamination from fracking. There is a transition period delaying full compliance until 2015.
- The CFTC and SEC adopted joint final rules that further define the terms "Swap Dealer," "Security-Based Swap Dealer," "Major Swap Participant," "Major Security-Based Swap Participant" and "Eligible Contract Participant" implementing provisions of the Dodd-Frank Act. These rules provide long-awaited guidance on which entities will be subject to various statutory and regulatory requirements, including registration, margin, capital and business conduct standards.
- The California Air Resources Board (CARB) released proposed regulations that would link California's cap-and-trade program to Quebec's program to form a joint carbon market. The proposal's regulations will be considered at CARB's June 28, 2012 regular meeting.

Recent Dos and Don'ts for Updated Market Power Study Filings

Daniel Hagan and Jane Rueger

It's that time again: Sellers with market-based rates that own or control generating facilities in the **Central Region** that did not file in December 2011 and are not exempt as Category 1 sellers must submit an updated market power study in **June 2012**. Sellers with market-based rates that own or control transmission facilities in the **Southwest Power Pool (SPP) Region** must also file in **June 2012**. The remaining sellers in the SPP Region that do not file in June 2012 and are not exempt as Category 1 sellers and transmission owners in the **Southwest Region** must file in **December 2012**. FERC's issuances in the past several months provide some useful guidance for sellers preparing their updated market power study filings:

All generating capacity owned or controlled by corporate affiliates must be attributed to the seller, regardless of upstream joint ownership with unaffiliated entities.

In addition to generating capacity owned or controlled by the seller itself, FERC requires a seller to attribute to itself all capacity owned or controlled by its affiliates in its pivotal supplier and market share screen analyses. Where a project company is jointly owned

Each bimonthly issue of the *Washington Energy Update* highlights useful energy regulatory tips and a wide range of issues impacting the energy markets.

If you have any questions or would like more information about anything appearing in this issue, please contact the editors or your White & Case relationship attorney. Please let the editors know if you would like a particular topic covered in a future issue or have suggestions on how this newsletter can be improved.

Editorial Contacts

Daniel Hagan
Partner, Washington, DC
+ 1 202 626 6497
dhagan@whitecase.com

Jane Rueger
Counsel, Washington, DC
+ 1 202 626 6534
jrueger@whitecase.com

White & Case LLP
701 Thirteenth Street, NW
Washington, DC
20005-3807
United States
Tel: + 1 202 626 3600
Fax: + 1 202 639 9355

by unaffiliated entities, FERC requires each upstream owner (and their affiliates) to take responsibility for 100% of the project company's generating capacity, and does not permit sellers to calculate a "derivative share" based on ownership interest. *In Kansas Energy LLC*, 138 FERC ¶ 61,107 (2012)(*Kansas*), FERC rejected a request for Category 1 status based on a derivative share test. Trademark Merchant Energy, LLC (Trademark), among others, argued that it met FERC's standards for Category 1 status, attributing to itself control over a portion of the generation owned by certain project companies in which Trademark's parent company held ownership interests ranging from 22% to 35%. Despite the letters of concurrence among the upstream owners that agreed to the proposed allocation of generation ownership, FERC rejected the derivative share approach, requiring Trademark to attribute to itself 100% of the generating capacity of its affiliated project companies in future updated market power analyses. FERC did differentiate situations involving jointly owned generating facilities (as compared to jointly owned project companies), confirming that FERC does permit co-owners to allocate a portion of jointly owned generation facility output based on ownership percentages. (*Kansas at P 29)*.

Pivotal supplier and market share screen analyses must take imports into account where a seller has first-tier affiliated generation.

In recent updated market power analyses, many sellers initially assumed no imports into their relevant geographic markets, but were required to supplement their filings in order to account for imports into the relevant market where their affiliates owned or controlled generation in first-tier markets. If an affiliate owns or controls generation in a first-tier market, this generation must be taken into account in the seller's analyses through an appropriate allocation of imports.

Seller category status must now be specified by region.

FERC's approach to inclusion of a seller's category status in its tariff has evolved over time. While many sellers initially complied with the requirement in Order No. 697-A that a seller include its category status designation in its tariff by including a blanket statement that seller was either a Category 1 seller or a Category 2 seller, FERC now requires category status to be designated for each of the six regions (Northeast, Southeast, Central, Southwest Power Pool, Northwest and Southwest). If a seller does not voluntarily propose a tariff change to identify its category status in each of the six regions prior to submitting its updated market power analysis, FERC staff will likely request that the seller file a revised tariff reflecting such information. Therefore, before filing an updated market power analysis, sellers should consider whether to submit a pre-emptive amendment to their tariffs to update category status language. If filing an amendment, sellers who have not previously established category status should include the necessary showing to establish the requested category status in each region.

Barriers to entry and vertical market power analyses must be nationwide in scope.

While FERC maintains a regional schedule for submission of updated market power analyses, FERC requires that the analyses and representations made with regard to barriers to entry and vertical market power be made on a nationwide basis, rather than limited in scope to the region currently under review. FERC staff has required supplements to filings where such analyses and representations were initially region-specific.

When performing the indicative screens, load-serving entities should not include their share of remote generation or the amount of any long-term firm purchases in Imported Power (Line D of the market share screen and the pivotal supplier screen) unless the resources do not have long-term firm reservations or rights to import power.

Specifically, FERC directed that "load-serving entities should add their share of remote generation to Installed Capacity (Line A of the market share screen and the pivotal market share screen) and the amount of any long-term firm purchases into Long-term Firm Purchases (Line B of the market share screen and the pivotal supplier screen) of the indicative screens, when load-serving entities have long-term firm transmission rights associated with these resources." Remote generation means generation capacity owned by a load-serving entity that is located outside its balancing authority.

Review asset appendices for accuracy and completeness.

FERC staff has recently focused its attention on the accuracy and completeness of sellers' asset appendices and has asked sellers to amend their filings with corrections to asset appendices if necessary. Common mistakes have included failure to use FERC-defined geographic regions in relaying the location of listed assets; failure to properly identify the names of corporate affiliates that own or control listed assets in the "Filing Entities" column; and failure to reflect all generation owned or controlled by the seller and its affiliates (as compared to a derivative share based on ownership).

FERC Seeks Comment on Potentially Sweeping Changes to Its Open Access and Priority Rights Policies Relating to Interconnection Facilities

Jane Rueger

On April 19, 2012, FERC issued a Notice of Inquiry (NOI) seeking comment from the industry regarding whether and how it should revamp its open access and priority rights policies as they apply to interconnection facilities (otherwise known as "generator lead lines"). By the breadth and nature of the questions asked in the NOI, it is apparent that FERC is considering implementation of sweeping changes to its current policies. If implemented, these changes are likely to have substantial impacts on generation developers, merchant transmission developers and traditional transmission providers alike.

Under its current policies, FERC treats certain interconnection facilities—most commonly long generator lead lines with high voltages—as transmission facilities for purposes of applying its open access policies, requiring developers of such facilities to file an Open Access Transmission Tariff (OATT) within 60 days of receiving a request for transmission service from an unaffiliated third party. Where the developer can demonstrate "specific, pre-existing generator expansion plans with milestones for construction of generation facilities and can demonstrate that it has made material progress toward meeting those milestones," FERC has granted priority rights for capacity on the interconnection facilities for the developer's future projects or expansions.

On March 15, 2012, FERC held a technical conference at which numerous parties raised concerns about these policies. Some commenters argued that the existing policies may have a negative impact on future development and financing of generation, particularly renewable resources such as wind that are often associated with long, high-voltage interconnection facilities. They also noted a common "free rider" problem that creates a disincentive for generation developers to be the first to build in a particular area, and thus the developer to build the interconnection facilities. Other commenters questioned the clarity of FERC's policy on priority rights on interconnection facilities, given that thus far FERC has granted such rights on a case-by-case basis and has not articulated a uniform set of criteria for granting them. Still other commenters asked FERC to proceed with caution in revising its policies, lest any changes tend to discriminate against existing transmission providers as compared to independent developers such as merchant transmission developers.

In its NOI, FERC identified two potential avenues for revising its current policies, described below. In addition to particular comment on the pros and cons of these two options, however, FERC also sought comment more generally, including whether any change to its current policies are necessary at all. FERC inquired whether its policies should differ depending on the size of interconnection facilities, and if so what the threshold for different treatment should be (e.g., length or voltage). FERC also appears to be considering possible implications for its merchant transmission policy, and whether there is a "meaningful distinction" between long, high-voltage generator interconnection facilities and merchant transmission facilities.

The first potential avenue identified by FERC for additional comment is to modify its existing OATT framework to better apply to interconnection facilities. Among many questions, FERC asked whether it should adopt a tailored pro forma OATT that is better adapted to the unique characteristics of interconnection facilities, for example, by eliminating provisions related to network service or Attachment K relating to system planning. The NOI seeks comment both on whether the concept of a tailored OATT would further FERC's goal of nondiscriminatory access to the grid and provide a commercially viable means to do so, and also on the details of what provisions should be removed from or added to the existing pro forma OATT in creating a tailored OATT. In addition, FERC sought comment regarding its current trigger for the filing of an OATT by a developer. Some have suggested that the current policy's trigger of a third-party service request imposes on the owner of the interconnection facilities too great a burden based on too little commitment from the third party; in the NOI, FERC asked whether the OATT filing should be triggered at some later point, such as when a generation interconnection agreement or a transmission service agreement is executed by the third party.

With respect to priority rights, FERC asked whether it should be more prescriptive regarding the standards and criteria used to grant priority rights. It also floated the concept of a safe harbor period during which the generation developer would not be subject to the open access rules, allowing phased development of generation projects during the safe harbor period. In addition to asking whether such a safe harbor is a useful concept, FERC asked such questions as how long such a safe harbor should be, what point in development should trigger the start of such a safe harbor period, what types of interconnection facilities should qualify for a safe harbor and whether intermediate development milestones should be required to maintain a safe harbor period.

The second avenue proffered for comment in the NOI would be to rely on modifications to the Large Generator Interconnection Agreement (LGIA) and Large Generator Interconnection Procedures (LGIP) to address third-party access to interconnection facilities.

Noting that the LGIA already contains provisions relating to third-party access to transmission providers' interconnection facilities, FERC asked whether the LGIA could be tweaked to apply also to the interconnection customer's interconnection facilities. Under this option, third parties might apply directly to the transmission provider, not the original interconnection customer, for access to excess capacity on the interconnection customer's interconnection facilities at the time they apply for service on the transmission provider's interconnection facilities and transmission system. FERC raised numerous questions about this approach as well, seeking comment on how to prevent discrimination against third parties by the original interconnection customer, what exact changes would need to be made to the LGIA and LGIP to implement this approach and what "collateral consequences" could ensue from adopting this approach. FERC also seeks comment on how to provide priority rights to interconnection customers' interconnection facilities for phased generation development under this approach.

Comments responding to the questions posed in the NOI are due June 26, 2012.

Qualifying Facilities—Items of Interest

Caileen Gamache

Qualifying Facilities (QFs) and the law that established QFs, the Public Utility Regulatory Policies Act of 1978 (PURPA), have been at the center of some recent developments involving notable issues. The first issue concerns the suggestion posed by FERC Chairman Wellinghoff that avoided cost rates incorporate compensation for the extra value of certain generators; the second issue pertains to developments regarding the ownership of Renewable Energy Certificates (RECs), which are often attributable to energy produced by QFs; and the final issue pertains to the size requirements of Small Power Production (SPP) QFs. These issues highlight some of the challenges QFs currently face.

Chairman Wellinghoff's Statement on Compensating Generators for Extra Value

At a March 21, 2012 webinar hosted by the American Council on Renewable Energy on the topic of waste energy recovery from industrial processes, FERC Chairman Wellinghoff announced a new internal FERC initiative pertaining to avoided cost rates under PURPA. The Chairman stated that he has directed FERC lawyers and policy experts to research whether the avoided cost rates utilities pay to QFs should include additional compensation to distributed generation because it offers more value to consumers than centralized generation.

Although the focus of the Chairman's remarks concerned distributed generation, he also spoke more broadly regarding a larger issue concerning compensating resources for added value. For example, he stated that FERC's Order No. 755, issued October 20, 2011, requires certain technologies such as flywheels, storage devices, and demand response resources to be paid more than conventional generation to provide frequency response because they offer more value. Frequency response is used by Independent Transmission Operators and Regional Transmission Organizations to balance supply and demand on the transmission systems they control. The Chairman explained that certain resources are more valuable because they can provide this service nearly instantaneously, whereas traditional generators require more time to ramp up and down. The more valuable resources should therefore be compensated in a manner that reflects that value, the Chairman maintained.

Similarly, the Chairman stated that distributed generation, including facilities that recycle the waste and heat of generation, offer extra value that may warrant extra remuneration. Distributed generation is generally perceived to offer additional efficiency benefits over centralized generation, such as the avoidance of line losses and a reduction in the need for new transmission lines. The Chairman, who acknowledged he was largely thinking out loud, suggested that such resources may therefore deserve extra compensation under PURPA.

The Chairman explained that his initiative is in its very early stages and that he did not yet know whether providing the extra compensation would be consistent with PURPA, which states that a utility is not required to pay more than the utility's avoided costs for purchases of energy and capacity from QFs. He also stated that certain laws may need to be modified before the compensation mechanism could be implemented. FERC issued a recent order that appears to have answered this question insofar as it concerns avoided cost payments under PURPA. As discussed further below, FERC clarified that the avoided cost payment to QFs under PURPA is strictly limited to the purchasing utility's avoided costs of generating the power itself or purchasing the power from another source. This clarification appears to preclude any proposal to incorporate additional compensation under the current PURPA avoided cost provisions.

Extrapolating from Chairman Wellinghoff's comments and the recent Order No. 755, there appears to be a trend at FERC towards identifying and incentivizing resources that are able to provide certain services in a superior manner. This trend could encompass many factors, including efficiency, enhanced reliability, availability, response time, proximity and other traits deemed by FERC to be desirable. In the event the Chairman's initiative results in revised regulations designed to reward QFs for certain characteristics, it might also open the discussion of QF compensation to other QFs that can point to any "extra value" benefits they provide.

REC Ownership

Today, most contracts between QFs and utilities specifically designate the owner of RECs and other "green attributes" that exist now or that may exist in the future. Many older contracts, however, did not contemplate the development of renewable portfolio standards and accompanying assets like RECs. Such contracts are therefore silent regarding the ownership of RECs. Adding to the complexity of the matter, QFs and their sales of energy at wholesale to utilities is generally governed by federal law, whereas RECs are state-created assets. In 2003, FERC made the first effort to address this issue in *American Ref-Fuel Co.,* 105 FERC ¶ 61,004 P 3 (2003) (*American Ref-Fuel Co.*) by granting a Petition for Declaratory Order regarding the ownership of RECs and "declar[ing] that contracts for the sale of QF capacity and energy entered into pursuant to PURPA do not convey RECs to the purchasing utility (absent express provision in a contract to the contrary). While a state may decide that a sale of power at wholesale automatically transfers ownership of the state-created RECs, that requirement must find its authority in state law, not PURPA." Although FERC provided guidance in *American Ref-Fuel Co.*, many aspects of REC ownership remain unsettled, as further discussed below.

Two QFs recently solicited further guidance from FERC regarding the ownership of RECs by filing Petitions for Enforcement of PURPA. The Petitioners allege that the Public Service Commission of West Virginia (WV PSC) violated PURPA by issuing a decision finding that RECs attributable to QFs are owned by the utility purchasers.

The first Petition was filed on February 24, 2012 in Docket No. EL12-36-000 by Morgantown Energy Associates (MEA), the owner and manger of a 50 MW qualifying cogeneration facility. The second Petition was filed on March 15, 2012 in Docket No. EL12-48-000 by the City of New Martinsville, West Virginia (the City). The City owns a hydroelectric QF consisting of two 18.7 MW generating station units. Both Petitioners are parties to long-term contracts executed in the 1980s pursuant to which they sell their respective QFs' electricity and capacity to utilities at the utilities' avoided cost rate. In 2009, the West Virginia legislature enacted a Renewable Portfolio Standards Act (WV RPS Act) establishing renewable energy requirements and creating a REC program within the state. The City has certified its QF under the WV RPS Act in order to produce eligible RECs within the state. MEA has certified its QF to sell RECs under other states' RPS programs, but has decided not to certify under the WV RPS Act.

On November 22, 2011, the WV PSC issued a declaratory ruling (Ruling) finding that a utility, Monongahela Power Co. (Mon Power), and an affiliate, Potomac Edison Co. (PE), own the RECs attributable to purchases Mon Power made from three QFs, including MEA and the City. The Ruling was based on three findings: "(i) consistent with the [WV RPS] Act, the utility that is obligated to purchase PURPA generation (which also qualifies as eligible generation under the [WV RPS] Act) should own the credits that exist for the purpose of measuring utility compliance with the portfolio standard, (ii) Mon Power and PE's ownership of the credits is based on their ownership of the qualifying energy as it is generated, and (iii) under the circumstances of the case in which the [WV RPS] Act and the [contracts] do not contain provisions that specify credit ownership by the utility or the QF, it is appropriate to consider equity and fairness and the impact of our decision on utility rates."

In their Petitions, MEA and the City claim that the WV PSC Ruling violates PURPA by i) finding that the "mere existence of a PURPA contract, at an avoided cost rate, constitutes compensation for RECs," despite agreement among the parties that the contract is silent with respect to RECs; and ii) by discriminating against Petitioners on the basis of their QF status as compared to the treatment of other generation sources that are eligible to generate RECs. Because MEA chose not to certify under the WV RPS Act, it also argues that the Ruling violates PURPA by authorizing the WV PSC or Mon Power to make a management decision for MEA by deeming it certified under the WV RPS Act contrary to MEA's own management decision.

Mon Power and PE filed a joint Protest, and the WV PSC filed a separate Protest to the Petitions (collectively, Protesters). Chief among the Protesters' counterarguments is that the ownership of state-created RECs is a matter to be decided under state law, not PURPA, and that the WV RPS Act grants ownership to purchasing utilities in West Virginia.

On April 24, 2012, FERC issued a Notice of Intent Not to Act and Declaratory Order notifying Petitioners that it would not initiate a PURPA action. Nevertheless, FERC held that certain statements in the WV PSC Ruling were inconsistent with PURPA. One example that FERC provided was the WV PSC's finding that the "substantial" avoided cost rate paid by Mon Power to Petitioners sufficiently compensated the QFs for the RECs. FERC clarified that avoided cost rates under PURPA are strictly the purchasing utility's avoided costs of generating the power itself or purchasing the power from another source. The utility is not required to pay more than these costs, and the costs are designed only to compensate QFs for such energy and capacity. Therefore, FERC concluded that the WV PSC Ruling is inconsistent with PURPA insofar as it finds that avoided cost rates under PURPA compensate a QF for RECs.

The April 24, 2012 order is a new development in this proceeding since we last reported on this issue in a March 29, 2012 Client Alert, linked here.

FERC Jurisdiction Over REC Transactions

In response to a proposed service schedule filed by WSPP Inc. (WSPP), FERC issued an order on April 20, 2012 accepting the service schedule and clarifying its jurisdiction over the sale of RECs. WSPP's service schedule, Service Schedule R, provides for the purchase and sale of three REC products, varying in firmness. The REC products may each be transferred independently or bundled with electric energy, and parties can elect to either allocate the contract price between RECs and the energy components of a bundled REC transaction, or use a single, unallocated price for both RECs and energy.

WSPP asked FERC to confirm that unbundled REC transactions are not subject to FERC's jurisdiction. FERC granted the request, concluding that unbundled REC transactions fall outside its jurisdiction, but that bundled REC transactions are within its jurisdiction under sections 201, 205 and 206 of the FPA. First, FERC explained that RECs are an instrument to certify that electric energy was generated pursuant to certain standards and are purely state-created and state-issued. Accordingly, neither RECs nor the contracts for the sale of RECs constitute jurisdictional activities of transmission of electric energy in interstate commerce or the sale of electric energy at wholesale in interstate commerce. FERC explained, however, that certain transactions that do not directly involve jurisdictional activities may nevertheless fall within FERC's jurisdiction if such transaction is "in connection with" or "affects" rates or charges within FERC's jurisdiction. When an unbundled REC transaction takes place independent of any wholesale sale of electric energy, it does not affect wholesale rates and does not fall within FERC's jurisdiction. In contrast, a bundled REC transaction involves the transfer of both RECs and wholesale energy and therefore the RECs "are charges in connection with a jurisdictional service that affect the rates for wholesale energy." Bundled transactions under Service Schedule R are therefore subject to FERC's jurisdiction. Moreover, FERC found it irrelevant whether or not the price for a bundled transaction is allocated between the REC component and the energy component. FERC also warned that parties cannot attempt to avoid FERC jurisdiction by simply separating a bundled transaction so that the energy and RECs convey pursuant to two separate agreements because "[c]ontract interpretation rules permit that where multiple instruments, executed contemporaneously or at different times, pertain to the same transaction, they will be read together, even if they do not expressly refer to each other."

QF Size Requirements

Under FERC's regulations, small power production facilities must not exceed 80 MWs unless they qualify for certain exemptions. To calculate the total capacity, an entity is required to include the capacity of any other small power production facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site. (18 C.F.R. § 292.204(a)). A facility will be deemed to be "at the same site" if they are located within one mile of the facility for which qualification is sought.

On July 11, 2011, Northern Laramie Range Alliance (Alliance) filed a petition for a declaratory order asking FERC to find that two Form 556 notices of self-certification filed by affiliates Pioneer Wind Park I, LLC and Pioneer Wind Park II, LLC (collectively, the "Projects") were void and without effect. The Alliance alleged that the owner of the Projects was "gaming" the QF regulations by claiming that the Projects were two separate facilities, each with a net capacity of approximately 48.6 MWs, when they were actually one large 97.2 MW facility. The Alliance concluded that FERC "cannot be bound by the one-mile standard in the face of such blatant attempted abuse." Xcel Energy Services Inc. filed comments on the proceeding stating generally that although it was not familiar with the specific facts at issue, the circumstances described in the Alliance's Petition "are consistent with a pattern that [it] has observed and are not isolated." FERC issued an order on March 15, 2012 denying the Petition and holding that the one-mile standard is not a "rebuttable presumption." Rather, the one-mile rule simply involves the measurement of the distance of the electrical generating equipment of the facilities at issue. Facilities either meet the requirement, or they do not meet the requirement. The Projects are located about 2.5 miles apart and therefore meet the size requirement for SPPs. The Alliance and Xcel Energy Services Inc. filed separate petitions for rehearing of FERC's order which are pending.