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EPA Proposes Significant Changes to Subpart W, Compliance Challenges Remain

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Over the last few months, the EPA has proposed important changes to Subpart W of the Mandatory Reporting of Greenhouse Gases Rule (Mandatory Reporting Rule or MRR).¹ In addition, the EPA finalized provisions that broadly expand the ability of covered entities to use best available monitoring methods (BAMMs) for compliance in the 2011 reporting year. These changes take important steps to reduce the reporting burden, but numerous compliance challenges remain (see page 3).

The Mandatory Reporting Rule requires owners and operators of facilities in 45 covered industries to report their greenhouse gas (GHG) emissions to the EPA. The MRR provides rules for all industries subject to reporting and uses industry-specific subparts to detail the precise requirements for measuring, monitoring, and reporting GHG emissions. The GHGs under the Mandatory Reporting Rule are defined to include carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), and the fluorinated hydrocarbons.

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DOE Adjusts its Delegation Proposal

By Stephen Angle and Andrew Beach

On October 11, 2011, the United States Department of Energy (DOE) announced that it will work more closely with the Federal Energy Regulatory Commission (FERC) in reviewing proposed electric transmission projects under section 216 of the Federal Power Act (FPA). DOE was considering a delegation of its obligation to conduct triennial congestion studies and its authority to designate national interest electric transmission corridors (NIETC) under the Energy Policy Act of 2005 (EPAc 2005) to the FERC. However, DOE determined that working with FERC is the “best way” to help “build the electric grid of the 21st century to compete in the global economy.”¹ DOE’s decision not to delegate its authority was in response to comments on the proposed delegation submitted by various stakeholder groups.

One reason that was offered for the proposed delegation is that transfer of the DOE-designated functions could make it easier to site interstate electric transmission projects, including those intended to facilitate the delivery of renewable energy across states. As suggested in the FERC staff narrative posted on DOE’s website, the delegation could have also avoided duplicative and possibly overbroad environmental review under the National Environmental Policy Act (NEPA). The delegation to FERC would have consolidated the congestion studies and NIETC designation authority with the backstop construction permitting authority for interstate transmission that was granted to FERC in EPAc 2005. Instead, DOE and FERC will work together to prepare drafts of the transmission congestion studies mandated by EPAc 2005, supplements to the congestion studies based on regional and inter-regional transmission plans to be prepared pursuant to FERC Order nos. 890 and 1000, and the NEPA analysis for any proposed NIETC. In addition, DOE announced other measures it would take to execute its FPA Section 216 powers “better, faster, with more transparency, and more effectively.”²

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Subpart W covers oil and gas production and distribution. Beginning on January 1, 2011, the following eight sectors were required to initiate monitoring and report their 2011 GHG emissions to the EPA by March 31, 2012:²

- **Offshore Petroleum and Natural Gas Production:** includes any platform, structure, or associated structure (including tanks and walkways) affixed to offshore submerged lands for the purposes of extracting, processing, and transferring hydrocarbons.
- **Onshore Petroleum and Natural Gas Production:** includes all equipment on or associated with a well pad used in the production of petroleum or natural gas as well as equipment for enhanced oil recovery.
- **Onshore Natural Gas Processing:** includes all processing facilities as well as the capture of CO₂ separated from natural gas streams and GHG emissions from gathering lines and boosting stations. All processing facilities that fractionate or have a throughput of at least 25 million cubic standard feet (MMscf) per day are covered.
- **Onshore Natural Gas Transmission Compression:** includes all stationary compressors that move natural gas at elevated pressure in transmission lines from fields or production facilities to distribution pipelines or storage.
- **Underground Natural Gas Storage:** includes any subsurface storage where gas has been transferred from its original location. This category also includes all wellheads connected to compression units located at the storage facility.
- **Liquid Natural Gas (LNG) Storage:** includes all onshore above ground LNG storage vessels as well as equipment associated with liquefying and regassifying LNG.
- **LNG Import and Export Facilities:** includes all equipment that receives LNG by ocean transport and delivers natural gas to the transmission and distribution system as well as equipment that receives natural gas and liquefies it for ocean transport.
- **Natural Gas Distribution Facilities:** covers all distribution pipelines and metering and regulating equipment that physically deliver natural gas to end users (does not include individual meters on end users' properties).

In general, the MRR requirements apply to facilities whose GHG emissions exceed 25,000 mtCO₂e/y,³ as well as certain other facilities expressly specified in the regulations. The Subpart W rules require monitoring of GHG emissions from covered facilities on January 1, 2011, with the first annual report, covering 2011 emissions, due to EPA by March 31, 2012.

As finalized, the original Subpart W rule raised a number of concerns and compliance challenges. Most significantly, many of the new measurements required to estimate GHG emissions were

seen as difficult, if not impossible, to complete in the first year of reporting. Some measurements required the installation of costly new equipment, while others proved dangerous or technically impossible. In addition, some aspects of the rule, most notably the requirement to collect data at the field level, proved confusing. In response to petitions for reconsideration filed by a number of industry groups, the EPA has proposed a series of rules to modify Subpart W's requirements intended to collect the high-quality data EPA seeks while easing the data collection burden on covered sectors.

New Rules for the Use of BAMMs

On September 27, 2011, the EPA finalized amendments to Subpart W that extend the amount of time in which BAMMs can be used for certain required measurements under the rule.⁴ Under the final rule, BAMMs may be used to estimate any parameter required for the calculation of GHG emissions during the 2011 reporting year without prior approval of the EPA.⁵ In order to use BAMMs after 2011, owners and operators of covered sources must submit a notice of intent to use BAMMs to EPA by December 31, 2011. After submitting the notice of intent, owners and operators have until March 30, 2012, to submit a BAMM request, which can automatically be used without approval through June 30, 2012. Between March 30 and June 30, 2012, EPA will review those BAMM requests seeking permission to use the BAMM for a longer period of time. Upon EPA approval, a requested BAMM may be used for the time period indicated by EPA, which is not to extend beyond December 31, 2012.

While EPA does not expect that it will be necessary, the new BAMM rule does include provisions for requests to use BAMMs beyond 2012.⁶ Any owner or operator that wishes to use BAMMs in 2013 or later must file a BAMM request by September 30 of the preceding year for EPA review. The BAMM request may be approved by the EPA if the Administrator is satisfied that the owner or operator is faced with unique or unusual circumstances.⁷ The rule provides examples of "unique or unusual circumstances," including safety concerns associated with data collection methods.⁸ The preamble further clarifies the criteria for approval, noting that BAMM will be approved in unique or unusual circumstances, but that "extreme" circumstances are not required, as suggested by the initial rule.⁹

The new BAMM rule provides a significant expansion of the flexibility granted to owners and operators to use available data and estimation techniques in their GHG emissions calculations. Under the original rule, BAMMs were only automatically available for well-related emissions and specified activity data and were set to expire by June 30, 2011.¹⁰ The original rule permitted the use of BAMMs for leak detection until the end of 2011, but these BAMMs were only available upon request to, and with approval granted by, the EPA.¹¹ ▶

Proposal to Extend the Reporting Deadline and Make Technical Corrections to the Rule

On August 4, 2011, the EPA proposed technical modifications to several subparts of the MRR including Subpart W.¹²

Most importantly, the proposal seeks comment on extending the submission deadline for 2011 monitoring data until September 28, 2012.¹³

Reconsideration of the Use of Field-Level Reporting for Onshore Production

Finally, on September 9, 2011, EPA proposed additional technical corrections to Subpart W, which respond in part to petitions for reconsideration filed by several industry groups. EPA's proposal announces that it plans to finalize the proposed rules before the end of 2011, and the final rules will apply to the first emission reports to be filed in 2012.¹⁴ EPA concluded that it would be reasonable to incorporate these significant changes into reports to be filed for 2011 because they are primarily designed to provide additional clarifications and flexibility in reporting, but do not affect the type of information that must be collected to complete an emissions report.¹⁵

The most significant change in EPA's reporting rule will effect reporting in the onshore oil and natural gas production sector. In the original rule, an onshore oil and natural gas production facility is defined as all wells within a basin,¹⁶ but many of the reporting requirements were tied to field-level data.¹⁷ The rule defined "field" by reference to the Energy Information Administration (EIA) 2008 field list, raising significant concerns about the delimitation of field boundaries as well as challenges regarding how wells not in fields on the EIA 2008 list should be reported. To address these concerns, the EPA has proposed to adopt a sub-basin approach.¹⁸ The proposal would use county boundaries as the limits of sub-basins and then define four categories of wells within each sub-basin.¹⁹ The four categories of wells would be defined as follows: (1) conventional; (2) shale; (3) coal seam; and (4) other tight reservoir rock.²⁰ Within each category, the proposed rule contemplates the use of operational criteria that will require multiple samples per sub-basin category for particular sources where the emissions profiles are variable.²¹

The rule also proposes a number of other clarifications and technical corrections to Subpart W.

The modification of the BMM rules and the proposed technical corrections to Subpart W make significant strides in easing the burden placed upon covered owners and operators with reporting obligations. However, the challenge ahead still remains significant. As 2011 draws to a close, it is essential that all owners and operators have Subpart W monitoring plans in place and ensure that these plans are being executed to collect all required data for reporting. While the expansion of the BMM rules certainly eases some data collection challenges, Subpart W reporting remains a significant undertaking. Among the challenges that remain for ▶

Subpart W of the Mandatory Reporting Rule raises a number of important compliance questions and challenges. Below is a subset of questions encountered in assembling a Subpart W compliance program.

1. How do I know if I have a Subpart W facility? How many Subpart W "facilities" do I have for which reports must be generated?
2. Who are the "owner" and "operator" of my Subpart W facility?
3. Why do I care about designated representatives in connection with Subpart W reporting and how do I select one?
4. How do I present and actually report the data to the governing agency? What is the "online reporting tool"?
5. Other than a designated representative, who may have access to EPA's online reporting tool?
6. If I have multiple operations in oil and gas sectors, does that affect the number of "facilities" that are regulated? How do I aggregate and report the data under Subpart W?
7. What equipment is within the scope of part of my Subpart W production facility that must be considered for reporting purposes?
8. How do I know that I am collecting all of the data that I will need for Subpart W reporting purposes?
9. Do I need agreements in place with contractors to collect data on portable equipment? What should such agreements look like, and do I have them in place?
10. Do I have a Subpart W compliance monitoring plan for each covered facility? What are the primary elements of such a plan? How do I know if I even need a monitoring plan?
11. What are Subpart W's calibration requirements? What do I do if I cannot meet those calibration requirements?
12. For purposes of reporting, how do I distinguish between an external combustion device and a flare?
13. If my Subpart W facility is also subject to Subpart C, how do I report the facility? Do I need a monitoring plan for the Subpart C components of my facility?
14. If I have a natural gas processing facility that is only subject to the MRR because of Subpart C requirements, is the facility also subject to reporting under Subpart W?
15. What do I do if the nameplate capacity of my facility exceeds the MRR threshold for reporting, but I believe that actual throughput will be below reporting levels?
16. How do I decide if my equipment is part of gathering and boosting (which is exempt from Subpart W reporting) or natural gas processing (which is subject to Subpart W reporting)?
17. How do I know if I need best available monitoring methods (BAMMs)? When and how do I apply for BAMMs?
18. How should I factor Subpart W's requirement that I report data for the whole year, regardless of when I acquired a facility, into my due diligence process when acquiring new assets?
19. What can I do to reduce my compliance risk resulting from the failure of field personnel to collect data?

For assistance addressing these and other Subpart W compliance questions, contact V&E attorneys [Larry Nettles](#), [Christopher Amandes](#), [Larry Pechacek](#), and [Margaret E. Peloso](#).

covered owners and operators are determining the number of facilities, selecting a designated representative for reporting, and collecting appropriate data from third party service providers to report emissions from portable equipment. ■

¹ 40 C.F.R. Pt. 98.

² 40 C.F.R. § 98.3(b). Note, however, that one of EPA's proposed rules would extend the reporting deadline to September 2012 for 2011 emissions under Subpart W.

³ The unit of measure for the Mandatory Reporting Rule is metric tons of CO₂ equivalent (mtCO₂e), this measurement requires that other reportable gases be converted using their global warming potential into a value that is equivalent to an amount of CO₂. For gases with a higher global warming potential, the amount in CO₂e will be greater than the actual amount of the gas emitted.

⁴ 76 Fed. Reg. 59533 (Sept. 27, 2011).

⁵ *Id.* 59535.

⁶ 76 Fed. Reg. at 59535.

⁷ 40 C.F.R. § 98.234(f)(8)(iii).

⁸ *Id.*

⁹ 76 Fed. Reg. at 59538.

¹⁰ 40 C.F.R. § 98.234(f)(2)-(3) (2010).

¹¹ *Id.* § 98.234(f)(4).

¹² 76 Fed. Reg. 47392 (Aug. 4, 2011).

¹³ 76 Fed. Reg. at 47396.

¹⁴ 76 Fed. Reg. 56010, 56020 (Sept. 9, 2011).

¹⁵ *Id.*

¹⁶ The rule adopts the American Association of Petroleum Geologists' definition of basin. 40 C.F.R. § 98.238.

¹⁷ 40 C.F.R. § 98.238 (2010). Under Subpart W as finalized one measurement from each field is required to estimate emissions from well completions, well workovers, and well unloading events.

¹⁸ 76 Fed. Reg. at 560026.

¹⁹ *Id.* at 56050.

²⁰ *Id.*

²¹ *Id.* at 26026.

DOE Adjusts, from page 1

Background

Section 1221 of EPAAct 2005 establishes the federal transmission backstop siting authority.³ DOE was directed to conduct, in consultation with affected states, a study of electric transmission congestion every three years. The DOE could, after considering recommendations from interested parties, including the states, designate a geographic area experiencing transmission congestion as a NIETC. Following notice and opportunity for hearing, FERC could authorize the construction of electric transmission facilities in a NIETC, if it finds that (i) a state does not have authority to approve the siting of the interstate transmission facilities or to consider the interstate benefits, (ii) the applicant is a transmitting utility under the Federal Power Act, but does not qualify to apply for state authorization of the transmission project because the applicant does not serve end-users in the state or (iii) the state that has authority to approve the siting of the interstate transmission facilities has withheld approval for more than a year after the applicant filed for authorization or conditioned its approval in a manner that the transmission project will not significantly reduce congestion or is not economically feasible.⁴

The implementation of the section 1221 of EPAAct 2005 has already been the subject of two U.S. Court of Appeals decisions. The Court of Appeals for the Ninth Circuit vacated DOE's congestion study and NIETC designations of eastern and western corridors when it determined that "DOE failed to properly consult with the affected states in conducting the Congestion Study and failed to undertake any environmental study for its NIETC Designation as required by the National Environmental Protection Act."⁵ In a proceeding on FERC's implementing regulations, the Court of Appeals for the Fourth Circuit found, among other things, that FERC's siting jurisdiction, which applies when a state withholds approval for more than a year, does not include, as FERC concluded in its implementing regulations, the situation in which a state denied an application.⁶

Comments on DOE Proposal

In light of the impediments to DOE's and FERC's ability to effectively use the backstop authority, DOE posted FERC staff comments on the proposal for DOE delegation under which FERC would consider applications for both a project-specific NIETC and construction permits within that NIETC in proceedings that run concurrent with state siting proceedings. DOE established a comment date for these proposals of September 9, 2011. DOE received numerous comments from interested parties, including state utility commissions, electric utilities, trade organizations, and not-for-profit entities. The state utility commissions predominantly opposed the delegation as an attempt to usurp the traditional transmission siting authority vested in the states. Interested parties that are opposed to the delegation argued that (i) DOE does not have the authority to delegate to FERC because it would be contrary to the specific division of responsibility in EPAAct 2005, (ii) the states are not the impediment to interstate transmission siting, (iii) FERC's statement that the *Piedmont* case is limited to the Fourth Circuit demonstrates FERC's intent to ignore the precedent outside of the Fourth Circuit, (iv) *ex parte* rules would prohibit the states from meaningfully participating in the FERC proceeding on project-specific NIETCs and construction permits, and (v) EPAAct 2005 required NIETCs that apply to a geographic area and not project-specific NIETCs. Many comments also raised questions on the interaction between the DOE delegation and FERC's Order No. 1000 on regional and inter-regional transmission planning.

Delegation Authority

On its face, DOE's general authority of delegation in section 642 of the DOE Organization Act (DOE Act) would permit it to delegate its functions under section 1221 of EPAAct 2005 to FERC. Under the DOE Act, FERC is an independent regulatory agency within DOE. section 642 states that "[e]xcept as otherwise expressly prohibited by law, and except as otherwise provided in this chapter, the Secretary may delegate any of his functions to such officers and ▶

employees of the Department as he may designate.”⁷ As noted in the comments opposed to delegation, EAct 2005 specifically provides for the division of responsibility. The statute does not expressly prohibit the Secretary’s delegation of those responsibilities as contemplated in section 642 of the DOE Act. Furthermore, section 402 of the DOE Act provides that FERC “shall have jurisdiction over any other matter which the Secretary may assign to the Commission after public notice.”⁸ Assuming DOE met the notice requirement, the delegation appeared to be consistent with the DOE Act.⁹

State Withholding Siting Authorization for More than One Year

Some issues raised in FERC’s narrative addressing the delegation were not resolved by DOE’s decision not to delegate its authority. One such issue is whether FERC will apply the federal backstop siting to projects rejected by states located outside the Fourth Circuit. Pursuant to EAct 2005, FERC has authority to issue a construction permit for transmission facilities in an NIETC if the state siting authority has withheld approval for more than one year after an application or has conditioned its approval such that the project will not significantly reduce transmission congestion or will not be economically feasible. In *Piedmont*, the Fourth Circuit rejected FERC’s interpretation that its right to issue a construction permit where a state withheld approval included a state denial of the siting application.¹⁰ However, the FERC staff indicated that the issue is not resolved in its narrative posted on DOE’s website, which states that

[t]o the extent that there may be a concern that DOE, FERC, and other involved agencies are ignoring, or seeking to circumvent, the mandates of the courts of appeals in the *Piedmont* and *California Wilderness Coalition* cases, it can be correctly noted that the effect of the *Piedmont* case is limited to the Fourth Circuit, and that other courts might reach a different result.

In addition to comments about FERC staff’s interpretation of the precedential value of the *Piedmont* decision, issues raised in stakeholder comments regarding the timing of review described in FERC staff’s narrative are still relevant. The comments questioned whether EAct 2005 permitted FERC to begin proceedings concurrent with state reviews, and whether concurrent proceedings would pressure state action. The issue of how EAct 2005 balances traditional state versus federal backstop siting authority is likely to be the subject of future litigation.

Transmission Companies Without Basis to Apply for State Certificate of Public Convenience and Necessity

It remains to be seen whether DOE and FERC working together will facilitate the development of transmission projects that seek to cross states to deliver energy where the project company does not qualify to apply for state siting authorization because it does not serve end-users in the state. The comments filed with DOE expressed concern regarding federal siting authority impinging on

states’ authority to site transmission lines. However, the issue of states’ rights is not present in cases where a transmission company is not able to request a state’s approval to site transmission because the transmission company does not serve end-users within that state. In these cases, the federal backstop siting authority in EAct 2005 is the only authority under which these transmission facilities can be sited. Although FERC has clear authority to process permit applications where the transmitting utility is unable to apply for state authority, the federal backstop authority has not been applied in these circumstances, possibly because DOE has been unsuccessful in designating NIETCs or has had prior designations vacated in *California Wilderness*. DOE’s plan to identify narrower areas of congestion and solicit statements from transmission developers while considering NIETC may help to facilitate these types of transmission projects.

Working Together

The decision for DOE and FERC to work together will maintain the division of responsibility contemplated in EAct 2005, but may not yield the same efficiencies as the delegation proposal. Although DOE and FERC will work together to conduct the triennial congestion studies in consultation with affected states, DOE will still be responsible for designating NIETC corridors with participation by interested parties. DOE has said that it will “[b]egin immediately to identify targeted areas of congestion based on evaluation of existing information and on comments submitted by stakeholders.”¹¹ DOE’s plan to begin immediately to identify targeted areas could be more effective than the delegation proposal because it eliminates a FERC rulemaking proceeding whereby FERC would have developed the process for designating NIETC. However, even with DOE’s proposal to consider narrower areas of congestion, DOE will still need to comply with *California Wilderness* by conducting a NEPA study of the proposed NIETC, albeit with FERC’s assistance. It is not clear from the announcement whether DOE and FERC will simultaneously conduct the NEPA review for the narrower NIETC with the construction permit application as contemplated in the delegation proposal. If the proposal for a concurrent environmental review of the NIETC designation and the application for the construction permit for the project has been abandoned, two separate NEPA documents will may need to be prepared for each proposed transmission project. ■

1 DOE and FERC Joint Public Statement on Backstop Siting.

2 *Id.*

3 Pub. L. No. 109-58, § 1221, 119 Stat. 594, 688 (2005).

4 *Id.*

5 *California Wilderness Coalition, et al. v. Dept. of Energy*, 631 F.3d 1072 (9th Cir. 2011).

6 *Piedmont Environmental Council v. FERC*, 558 F.3d 304 (4th Cir. 2009), *cert denied*, *sub nom* Edison Elec. Inst. v. *Piedmont Envtl. Council*, 130 S.Ct. 1138, 175 L. Ed. 2d 972 (2010).

7 42 U.S.C. § 7252.

8 42 U.S.C. § 7172(e).

9 Comments filed with DOE by certain interested persons question whether the notice of the proposed delegation was sufficient.

10 Note 6, *supra*.

11 DOE and FERC Joint Public Statement on Backstop Siting.

EPA Proposes 2012 RFS-2 Targets Applicable to Cellulosic Biofuels

By Jay Rothrock and Joseph Pollak

U.S. cellulosic biofuel obligations for 2012 will once again fall dramatically short of statutory targets. The United States Environmental Protection Agency (the “EPA,” or the “Agency”) recently proposed cellulosic biofuel obligations for 2012 under the RFS-2 renewable fuel standard program. The proposed obligations fall well short of the statutory targets set out in the 2007 Energy Independence and Security Act (the “EISA”).

Cellulosic biofuels are chemically identical to conventional, grain-based biofuels, but are made by processing non-food sources. Producing the most popular conventional biofuel, corn-ethanol, requires diverting corn that would otherwise be used for food or animal feed to energy production, which may increase food costs. In the alternative, conventional feedstock producers could acquire more land to plant, water, fertilize, and harvest corn specifically for use as fuel, but the additional commitment of natural resources and fossil fuels required for large-scale conventional feedstock production may tend to counteract the environmental advantages of conventional biofuels. In contrast, feedstocks for cellulosic biofuels often come from agricultural waste like corncobs and stalks and therefore do not compete with food use or require additional cultivation.

The EISA established a requirement that the United States increasingly rely on biofuels for its energy needs.¹ The target requirement increases annually until it reaches 36 billion gallons of renewable fuels used in 2022 and, each year, cellulosic biofuels are scheduled to make up an increasing portion of the entire renewable fuel requirement.² The EISA calls for 500 million gallons of cellulosic biofuel to be blended into the domestic fuel supply in 2012,³ but EPA has exercised its authority to revise this number downward, and proposed a 2012 obligation of between 3.45 and 12.9 million gallons.⁴ However, even this lower obligation may be overly optimistic. In 2011, EPA called for 6.6 million gallons of cellulosic biofuel to be blended into the domestic fuel supply,⁵ but actual production fell far short of that goal, and blenders were required to purchase compliance credits from EPA to make up the difference.⁶ Although the 2012 cellulosic biofuel obligations may require an even lower volume to be blended than was required in 2011, many in the industry doubt that 2012 production will be sufficient to meet even the low end of EPA’s proposed range.⁷

The RFS-2 Program

Title II of the EISA amended section 211(o) of the Clean Air Act (the “CAA”) to create the RFS-2 program and required EPA to promulgate regulations to implement the renewable fuel standards.⁸ Section 211(o) set a long-term requirement that the United States

use at least 36 billion gallons of renewable fuel by 2022, with 16 billion gallons coming specifically from cellulosic ethanol.⁹

Under the RFS-2 regulations, obligated parties, such as refiners and importers of gasoline and diesel fuel, must demonstrate that they have met their annual renewable volume obligation (RVO) by using certain quantities of biofuels.¹⁰ Producers of renewable fuels must comply with specific rules to generate serial numbers, called renewable identification numbers (RINs), which are assigned to particular batches of biofuel.¹¹ Obligated parties purchase biofuel from producers and submit the RINs to EPA to prove that they have used the biofuels and are in compliance with their RVO.¹²

Setting RVOs

The EISA requires EPA to set national volume targets for production of several categories of renewable fuels, including cellulosic biofuels. To meet the volume targets, obligated parties must use a certain ratio of renewable fuels as a part of overall fuel production or import. The required ratio, called the percentage standard, changes each year as the national volume targets increase. EPA calculates an RVO for each obligated party based on a formula that includes the percentage standard and the obligated party’s expected volume of overall fuel production.¹³

CAA section 211(o) requires that EPA set the cellulosic biofuel volume target based on the volume of cellulosic biofuel projected to be available during the following year.¹⁴ EPA uses both Energy Information Administration (the “EIA”) data and information from industry in making this projection.¹⁵ Nonetheless, EPA’s 2010 volume target of 5 million gallons of cellulosic biofuel proved overly ambitious.¹⁶ Although final EIA figures are not yet available, Nathanael Greene of the Natural Resources Defense Council estimated 2010 actual production was roughly 1 million gallons.¹⁷ EIA Administrator Richard Newell communicated to EPA that cellulosic biofuel production would only reach 3.94 million gallons this year,¹⁸ but EPA nonetheless set the 2011 volume target at 6.6 million gallons,¹⁹ and it appears likely that the 2011 volume target will not be achieved. EPA has proposed a 2012 volume target between 3.45 and 12.9 million gallons and is required to publish the final 2012 volume target by November 30, 2011.²⁰

Given the rationale that EPA uses in setting the annual volume targets applicable to cellulosic biofuel under the RFS-2 program, it is unsurprising that cellulosic biofuel production has not been sufficient to meet recent years’ volume targets. EPA has stated that its focus in setting the annual volume targets is on potential production – not the production values that are expected, but rather those that are “potentially attainable.”²¹ EPA maintains that this approach is best suited to satisfy the goals of the RFS-2 program by establishing an incentive to stimulate increased production.²² From industry’s prospective, however, unrealistic targets operate in effect as a tax, requiring obligated parties under the standard to purchase compliance credits from EPA when it is impossible to ▶

purchase sufficient volumes of cellulosic biofuel due to insufficient production.²³ For these reasons, the American Petroleum Institute and the National Petrochemical and Refiners Association recently submitted to EPA a petition to reconsider the final rulemaking setting the 2011 RVOs, but EPA denied this petition in its recent notice of proposed rulemaking for the 2012 annual targets.²⁴ Indeed, the Agency appears poised to continue its focus on potential production in setting future targets under the RFS-2 program.

Obstacles to Cellulosic Biofuel Production

Lackluster production volumes raise questions about the effectiveness of federal government programs designed to assist in the development of cellulosic biofuel production facilities. Additionally, many of these programs face significant political or financial uncertainties that could restrict their ability to spur cellulosic biofuel production in the future.

Loan Guarantee Programs

Both the U.S. Department of Energy (the “DOE”) and Department of Agriculture (the “USDA”) offer loan guarantees to support the construction of cellulosic ethanol production facilities.

DOE’s Loan Programs Office administers two loan guarantee programs that are applicable to biofuels under Title XVII of the Energy Policy Act of 2005.²⁵ The Section 1703 Program is named for the section number of its authorizing legislation and was enacted to further the commercial availability of innovative clean technology, including renewable energy systems.²⁶ Though the Energy Policy Act was enacted on August 8, 2005, regulations were not finalized until 2009, and the first loan guarantee was not announced until December of that year. To date, only four projects have been funded under the Section 1703 Program, none of which relate to cellulosic biofuel research or production. Part of the reason why so few projects have been funded under the Section 1703 Program thus far is because the program requires loan guarantee recipients to pay the Credit Subsidy Cost, which is the government’s estimated cost for providing the loan guarantee, at closing, which can be several million dollars.²⁷ This additional expense makes the Section 1703 Program much less attractive than alternative programs that might be available to the same applicants and do not require payment of the Credit Subsidy Cost.

The more popular DOE loan guarantee program is the Section 1705 Program. The American Recovery and Reinvestment Act of 2009 amended the Energy Policy Act of 2005 to create a temporary program to provide funding for innovative clean technology in specific areas, including biofuels projects performing at pilot or demonstration levels.²⁸ Unlike Section 1703, Congress appropriated funds to cover the Credit Subsidy Cost of Section 1705 loan guarantees so that recipients do not have to pay the Credit Subsidy Cost at closing.²⁹ However, the window of opportunity for Section

1705 funding has largely shut; DOE’s authority to enter into new agreements under the Section 1705 program expired on September 30, 2011, and approved projects must have commenced construction prior to that date.³⁰

Unlike the Section 1703 Program, the Section 1705 Program has a history of funding cellulosic biofuel projects. The first loan guarantee under the Section 1705 Program was announced in July 2009, and now, more than 30 projects have been funded, including two cellulosic ethanol programs. The first cellulosic ethanol project to receive a Section 1705 loan guarantee was a \$105 million loan guarantee awarded in July 2011 to Poet LLC to support its construction of an Emmetsburg, Iowa, plant designed to make 25 million gallons of cellulosic ethanol per year from agricultural waste such as corncobs and husks.³¹ A \$133.9 million conditional loan guarantee for Abengoa Bioenergy Biomass in Hugoton, Kansas, followed in August 2011. Abengoa’s planned facility is expected to create 23 million gallons of cellulosic ethanol annually out of corn stalks and leaves.³²

The USDA also offers a loan guarantee program applicable to cellulosic biofuel projects through its broader Biorefinery Assistance Program. The program is administered by the USDA Rural Development Program and intended to support the development and construction or retrofitting of commercial-scale biorefineries. It was authorized by the 2008 Farm Bill, which included mandatory funding for the program through 2012.³³ The program, which favors projects located in non-urbanized areas with fewer than 50,000 residents,³⁴ has provided loan guarantees for three cellulosic ethanol projects in to date. In January 2011, INEOS New Planet BioEnergy LLC received a \$75 million loan guarantee to support construction of a plant near Vero Beach, Florida that will produce 8 million gallons of ethanol per year³⁵ using feedstocks that include orange peels and household waste.³⁶ The project finalized its private funding in August 2011, and construction is scheduled to be completed in May 2012. That same month, the USDA awarded Coskata, Inc., a \$250 million loan guarantee — the largest loan guarantee ever granted for a cellulosic ethanol project — to construct a 55 million-gallon-per-year biorefinery producing cellulosic ethanol from wood chips. The company began operating a pilot plant in 2009 and expects to finalize private funding and begin construction of the commercial plant in the fourth quarter of 2011.³⁷

Research and Development Grants

DOE and USDA jointly offer grant funding for biofuels research and development and for construction of pilot and demonstration plants. The Biomass Research and Development Initiative was authorized by the 2008 Farm Bill³⁸ and the Energy Policy Act of 2005.³⁹ Recipients’ projects must integrate feedstock development, biofuel product development, and biofuel development analysis.⁴⁰ Additionally, the Recovery Act allocated \$480 million to DOE for ▶

grants of up to \$50 million to construct biorefinery demonstration plants and \$25 million for biorefinery pilot plants.⁴¹ DOE provided grants to 14 projects under this one-time program, including pilot plants for cellulosic ethanol technology which will be used by the INEOS and Abengoa commercial biorefineries.

Though these temporary grant programs have resulted in some successes, most notably a December 2009 grant to Enerkem Corporation to develop a waste-to-biofuels process that eventually resulted in a planned commercial facility supported by USDA loan guarantees, the sources of research and development funding that are currently authorized are unlikely to result in significant, short-term increases in cellulosic biofuel production. For instance, most of the recipient projects of DOE/USDA Biomass Research and Development Initiative funds in 2011 were sponsored by research institutions, as opposed to construction projects for commercial purposes. The largest grant was \$6.9 million awarded to the University of Kentucky to support a four-year study of growing biofuel feedstocks.⁴² In September 2011, USDA announced \$136 million in grants over five years to universities studying biomass crop production.⁴³

Indeed, the opportunity to use federal grant funds to build a demonstration plant and then a federal loan guarantee to enlarge the demonstration plant into a commercial facility may not be available to future projects. The Recovery Act funds that supported Enerkem's grant were made possible through a one-time allocation to DOE that has not been renewed. USDA's Section 1703 Program does not allow loan guarantees for projects that have already received federal grants, and the Section 1705 Program expired on September 30, 2011.⁴⁴

Future Uncertainty

The slate of expiring funding opportunities underscores the uncertain state of federal funding for cellulosic ethanol going forward. In February 2010, a federal biofuels taskforce, which included both the Energy and Agriculture Secretaries, issued a report on the state of biofuel production in the United States.⁴⁵ The report called for loan guarantees and research funding targeted at increasing production outcome to meet cellulosic biofuels targets.⁴⁶ Nonetheless, there have been no indications that these expiring programs will be reauthorized anytime soon. However, although funding for new programs may be in doubt, Congress has made some provisions for currently pending proposals. For instance, the expiration of DOE's Section 1705 Program may not have much effect on cellulosic ethanol projects which are waiting for Section 1705 funding because Section 1705 applications received before February 24, 2011, can be paid from Section 1703 funds.⁴⁷ Any of these pending Section 1705 projects that are ultimately funded with Section 1703 funds will still be able to avoid paying for the Credit Subsidy Costs.⁴⁸ However, without Congressional action, new projects could only be funded through the Section 1703 Program, which has not guaranteed a loan for a

cellulosic biofuel facility to date. Moreover, any new projects guaranteed through the 1703 Program would be required to pay their own Credit Subsidy Cost, perhaps making these loan guarantees prohibitively expensive to many applicants.

USDA's loan guarantee program may be subject to modification as well. The Section 9003 Biorefinery Assistance Program was initially funded through Fiscal Year 2012, and its future will depend on Congressional reauthorization. Secretary of Agriculture Tom Vilsack has signed a policy memorandum encouraging the development of biofuels to improve both the environment and economy and seems likely to lobby Congress for reauthorization.⁴⁹

One obstacle to reauthorization is the ongoing criminal investigation of Solyndra, Inc., and actions taken during its application for a DOE Section 1705 loan guarantee.⁵¹ Solyndra received a \$535 million loan guarantee to construct a facility to manufacture solar cells, but filed for bankruptcy in September 2011. Some members of Congress have questioned DOE's management of Solyndra's loan guarantee. The current attention on Solyndra and the possibility of a political shakeup in the 2012 election add doubt to the future of both the DOE and USDA loan programs.

The future of the RFS-2 program itself is also far from assured. Many industry advocates suggest that the program's underwhelming results to date are attributable to its failure to create a robust, accessible market for renewable fuels. A popular point of view suggests that renewable fuels funding should be redirected from tax credits and loan guarantees to infrastructure projects that may more readily support a market for the fuels themselves.⁵² Under this line of reasoning, EPA's consecutive downward revisions to the cellulosic biofuel RVOs have sent a negative signal to industry, suggesting that the investments required to create a market for the fuels are unlikely to pan out.⁵³ Nevertheless, there are some signals that policymakers may be reluctant to abandon the current approach at the moment; recent attempts to cut tax credits for ethanol blenders were defeated in the Senate.⁵⁴ However, there is also speculation that some Democratic votes that helped defeat the measure were driven by procedural considerations rather than the underlying policy, suggesting that a renewed future effort may yield different results.⁵⁵

Given the current political dynamic in Washington, the upcoming 2012 elections, and the questionable success of the RFS-2 program in spurring cellulosic biofuel production, the nation's approach to renewable fuels may be at a turning point. Congress could reauthorize expiring programs upon which expansion of the fledgling cellulosic biofuel industry currently relies, or political gridlock might persist through the 2012 election, leaving the biofuels industry largely unsupported. Alternatively, economic conditions may support renewed consideration of how to best ramp up cellulosic biofuel production in an effort to spur the development of green jobs. These larger questions aside, cellulosic biofuel producers and blenders will anxiously await EPA's final rulemaking setting the 2012 RVOs, which must be completed ▶

by November 30, 2011. EPA's action in that rulemaking will go a long way toward answering perhaps the most important question facing the industry at the moment: will 2012 cellulosic biofuel production be sufficient to meet the EPA's target? ■

- ¹ Energy Independence and Security Act (the "EISA") of 2007, 42 U.S.C. § 7545(o)(2) (2010).
- ² *Id.* § 7545(o)(2)(B).
- ³ *Id.* § 7545(o)(2)(B)(i)(III).
- ⁴ 76 Fed. Reg. 38844 (July 1, 2011).
- ⁵ 75 Fed. Reg. 76790 (Dec. 9, 2010).
- ⁶ Jenny Mandel, *Refiners Protest EPA's 'Ridiculous' Cellulosic Targets*, Environment & Energy Daily (June 22, 2011).
- ⁷ See generally *id.*
- ⁸ See Pub. L. No. 110-140, §§ 201 – 210, 121 Stat. 1492, 1519-1532 (codified at 42 U.S.C. § 7545(o)).
- ⁹ 42 U.S.C. § 7545(o)(2)(B).
- ¹⁰ 40 C.F.R. § 80.1406 (2010).
- ¹¹ *Id.* § 80.1426.
- ¹² *Id.* § 80.1427.
- ¹³ *Id.* § 80.1127 (2010).
- ¹⁴ 42 U.S.C. § 7545(o)(3).
- ¹⁵ See, e.g., 76 Fed. Reg. 38844, 38849-53 (July 1, 2011) (providing an overview of existing and potential cellulosic biofuel facilities in making the 2012 volume projection).
- ¹⁶ Dina Fine Maron, *Much-Touted Cellulosic Ethanol is Late in Making Mandated Appearance*, Environment & Energy Daily (Jan. 11, 2011).
- ¹⁷ *Id.*
- ¹⁸ Allison Winter, *White House clears new goals for RFS program*, Environment & Energy Daily (Nov. 23, 2010).
- ¹⁹ 75 Fed. Reg. 76790 (Dec. 9, 2010).
- ²⁰ 40 CFR § 38846.
- ²¹ See 75 Fed. Reg. 76790, 76794 (Dec. 9, 2010) ("[W]e explored the 2011 volumes for individual companies as projected by EIA to determine not only what volumes might be anticipated, but more importantly what volumes were potentially attainable.").
- ²² See 76 Fed. Reg. 38844, 38881 (July 1, 2011) ("[W]e believe that the volume of cellulosic biofuel actually produced in a given year is likely to be strongly influenced by the standard we set.").
- ²³ See, e.g., Mandel, *supra* note 4 (quoting the president of the National Petrochemical & Refiners Association referring to the credit-purchasing requirement as a "tax" and a "surcharge").
- ²⁴ 40 CFR § 38844 *et seq.*
- ²⁵ Energy Policy Act of 2005, Title XVII, 42 U.S.C. § 16501 *et seq.* (2011).
- ²⁶ 42 U.S.C. § 16513(b).
- ²⁷ *Id.* § 16512(b)(2).
- ²⁸ American Recovery and Reinvestment Act of 2009 § 406, 42 U.S.C. 16516.
- ²⁹ 42 U.S.C. § 16512(a).
- ³⁰ *Id.* § 16516(a).
- ³¹ Bill Tomson, *U.S. to Help Finance Cellulose Ethanol Plant*, Wall St. Journal, July 7, 2011.

- ³² Department of Energy, *Department of Energy Offers Abengoa Bioenergy a Conditional Commitment for a \$133.9 Million Loan Guarantee*, Aug. 19, 2011, <http://energy.gov/articles/department-energy-offers-abengoa-bioenergy-conditional-commitment-1339-million-loan>.
- ³³ Food, Conservation, and Energy Act of 2008 § 9003, 7 U.S.C. § 8103.
- ³⁴ 7 U.S.C. § 8103(e)(1)(C)(vii); see also 7 C.F.R. § 4279.265(d)(8).
- ³⁵ INEOS New Planet Bioenergy, *INEOS Bio JV Closes \$75m in Private Financing Under USDA Loan Guarantee Program for Advanced BioEnergy Center in Florida*, Aug. 18, 2011, <http://www.inpbioenergy.net/news/view.html?id=25>.
- ³⁶ *Id.*
- ³⁷ Coskata, Inc., *Coskata Completes First Close of Series D Financing*, Aug. 21, 2011, <http://www.coskata.com/media/index.asp?story=B0130A68-DD3A-41A7-9999-EAD446171209>.
- ³⁸ Food, Conservation, and Energy Act of 2008 § 9001(a), 7 U.S.C. § 8108.
- ³⁹ Energy Policy Act of 2005 § 210, 7 U.S.C. § 8108.
- ⁴⁰ See Food, Conservation, and Energy Act of 2008 § 9001(a).
- ⁴¹ Department of Energy, *DOE Announces Nearly \$800 Million from Recovery Act for Biofuels*, May 5, 2009, http://apps1.eere.energy.gov/news/daily.cfm/hp_news_id=164.
- ⁴² Mary Meehan, *UK gets \$6.9 Million Federal Grant to Help Reduce Reliance on Foreign Oil*, Lexington Herald-Leader, May 6, 2011, <http://www.kentucky.com/2011/05/06/1731563/uk-gets-69-million-federal-grant.html>.
- ⁴³ USDA Office of Communications, *Agriculture Secretary Vilsack Announces Major Investments to Spur Innovation and Job Creation in Research, Development and Production of Next Generation Biofuels*, Sept. 28, 2011, <http://www.usda.gov/wps/portal/usda/usdahome?contentid=2011/09/0425.xml>.
- ⁴⁴ H.R. 1473, 112th Cong § 1425 (2011).
- ⁴⁵ Biofuels Interagency Working Group, *Growing America's Fuel: An Innovation Approach to Achieving the President's Biofuels Target*, Feb. 4, 2010.
- ⁴⁶ *Id.* at 1.
- ⁴⁷ H.R. 1473, 112th Cong § 1425 (2011).
- ⁴⁸ *Id.*
- ⁴⁹ USDA, *Agriculture Secretary Vilsack to Sign MOU to Support Continued Development of Biofuels and Related Products*, Feb. 25, 2011.
- ⁵⁰ Steven Mufson and Joe Stephens, *Solyndra Executives Will Invoke the Fifth at House Hearing*, Washington Post, Sept. 21, 2011.
- ⁵¹ Carol D. Leonnig and Joe Stephens, *Chu Takes Responsibility for a Loan Deal that Put More Taxpayer Money at Risk in Solyndra*, Washington Post, Sept. 29, 2011.
- ⁵² See, e.g., Jenny Mandel, *EPA ruling lowers 2011 targets for cellulosic ethanol*, Environment & Energy Daily (Nov. 29, 2010) (quoting a biofuel industry group as stating that "the lack of access to the market" is what is preventing cellulosic ethanol use, and suggesting that federal payments for ethanol use should be redirected to support infrastructure development to support the industry).
- ⁵³ See Fine Maron, *supra* note 15 (stating that EPA's lowering of cellulosic biofuel requirements "cools interest from private investors").
- ⁵⁴ Jenny Mandel & Elena Schor, *Senate defeats Coburn amendment to strip federal subsidies*, Environment & Energy Daily (June 14, 2011). Though the measure sought to strip current federal tax credits for ethanol blenders, the amendment did not include any provisions to redirect these funds to other programs, such as infrastructure improvements, to benefit the renewable fuel industry.
- ⁵⁵ *Id.*

California Cap-and-Trade Regulations Finalized

Brandon Tuck and Hana Vizcarra

The California Air Resources Board (CARB) approved final regulations for the cap-and-trade program mandated by Assembly Bill 32 (AB 32) on October 20, 2011. AB 32 requires California to reduce greenhouse gas (GHG) emissions to 1990 levels by the year

2020.¹ CARB's new regulations "cap" the volume of pollutants that all major GHG producers can collectively emit within the state.²

CARB will establish a maximum number of annual allowances, with each allowance equaling one metric ton of carbon dioxide equivalent, and this will determine the volume of pollutants that can be emitted within the cap.³ The number of allowances issued each year by CARB will decline each year as the cap decreases.⁴ Additionally, CARB will authorize a limited amount of emissions reductions offset credits in areas not subject to the cap.⁵ After the ▶

end of each compliance period, covered entities must surrender enough compliance instruments (both allowances and offsets) to match their emissions during that period, and thus fall under the “capped” amount of emissions they are allowed to produce in that given year.⁶ The first compliance period is scheduled for 2013 through 2014.

Obtaining Compliance Instruments

The cap-and-trade program requires regulated GHG emitters to surrender compliance instruments for each metric ton of carbon dioxide equivalent GHG emissions.⁷ Some entities will receive free allowances from the state, and all entities may purchase offsets, allowances at auction or from the state’s reserve, or allowances from other entities.

Offset Credits and Credit Producing Projects

The rules outline two types of offset credits: (1) Registry Offset Credits, issued by non-CARB entities⁸ and (2) CARB Offset Credits. Both types of credits must represent GHG emissions reductions or GHG removal enhancements that are “real, additional, quantifiable, permanent, verifiable, and enforceable”⁹ and result from projects designed according to the requirements of approved Compliance Offset Protocols.¹⁰

Projects that produce these offset credits must comply with the requirements outlined in the Compliance Offset Protocol for that project type. The regulations have four approved Protocols for: (1) ozone depleting substances projects, (2) livestock projects, (3) urban forest projects, and (4) U.S. forest projects.¹¹ Projects must be located in the U.S., its territories, Canada, or Mexico.¹² All projects are subject to detailed monitoring, reporting, and record retention requirements (MRR) as well as verification requirements. Some projects that began prior to the enactment of regulations may be able to receive credits as Early Action Offset Credits. Subarticle 14 addresses which projects would qualify. In addition, Sector-Based Offset Credits allow for Reducing Emissions from Deforestation and Forest Degradation (REDD) projects in developing countries to be considered for credits.

Trading Features

Entities that purchase excess compliance instruments or that reduce their GHG emissions below the number of compliance instruments they hold may trade them to other covered entities.¹³ The regulations contain some restrictions on trading to prevent fraud and market manipulation.¹⁴ In addition, entities may bank excess allowances for current or previous compliance periods.

Fraud and Manipulation Safeguards

CARB’s regulations include requirements designed to safeguard against fraud and manipulation, including, but not limited to: registration with CARB prior to receiving a permit to hold a compliance instrument, disclosure of direct and indirect corporate relationships and beneficial holding relationships, and maintenance registration of each transaction with CARB. Monitoring and surveillance groups are also charged with identifying and preventing suspicious market activity.

Linkage

The regulations allow California companies to use compliance instruments issued by other GHG emissions trading systems to meet the cap-and-trade requirements if CARB has approved linkage with that trading system.¹⁵ In addition, there is a section reserved for regional linkage with the Western Climate Initiative (WCI),¹⁶ an agreement among 11 states and Canadian provinces to cooperate in the development of a cap-and-trade program that would lower GHG emissions 15 percent below 2005 levels by 2020.¹⁷ However, a changing political landscape has slowed progress of WCI initiatives in other member states. ■

V&E continues to track developments in the California carbon markets. For more information on this topic contact [Larry Nettles](#), [Margaret E. Peloso](#), [Brandon Tuck](#), and [Hana Vizcarra](#).

¹ California Health & Safety Code §§ 38500 et seq., (Sept. 27, 2006), available at http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf.

² California Air Resources Board, Supplement to the AB 32 Scoping Plan Functional Equivalent Document 12 (July 13, 2011), available at http://www.arb.ca.gov/cc/scopingplan/document/Supplement_to_SP_FED.pdf.

³ California Air Resources Board, October 2011 Final Regulation Order, Article 5: California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (October 2011), [hereinafter “Cap-and-Trade Regulations”] available at <http://www.arb.ca.gov/cc/capandtrade/finalregorder.pdf>.

⁴ *Id.*

⁵ *Id.* §§ 95970 through 95988. The four initial ways that a company can get an offset are projects that promote forestry, urban forestry, urban livestock management, and the removal of existing stock of ozone-depleting substances.

⁶ *Id.* § 95856.

⁷ *Id.* § 95856(a).

⁸ An Offset Project Registry is “an entity that meets the requirements of section 95986 and is approved by ARB that lists offset projects, collects Offset Project Data Reports, and facilitates verification of Offset Project Data Reports for offset projects being implemented using a Compliance Offset Protocol.” See *Id.* § 95802(a)(173).

⁹ *Id.* § 95802(a)(11) and § 95970(a)(1).

¹⁰ *Id.* § 95970.

¹¹ *Id.* § 95973.

¹² *Id.* § 95972(c).

¹³ *Id.* § 95921.

¹⁴ *Id.*

¹⁵ *Id.* § 95940.

¹⁶ *Id.* § 95943.

¹⁷ Western Climate Initiative website available at: <http://www.westernclimateinitiative.org/index.php>.

Electricity Market Reform and Low Carbon Initiatives in the United Kingdom – or – The Good, the Bad and the Ugly: Challenges for Investors in UK Energy Infrastructure

By Mark Coker, Raina Lal, and Kevin Atkins

Introduction

At a recent London conference on low-carbon investment, the head of a private equity fund specializing in renewables chilled his audience with a report on the significant gap between investor expectations on risk and return and what was then being achieved under the UK regulatory environment. Have the legislative developments in the last six months closed that gap?

The UK's long-term energy policy revolves around three fundamental issues — low carbon, security of supply, and affordability — the “trilemma.” Each one of these issues in isolation can be solved: however, the key is to find a solution that manages all three of these drivers. In particular the reduction of CO₂ emissions requires significant long-term investment and finding a way to achieve this while securing the UK's energy needs without increasing the costs paid by the consumer is the current political imperative. This situation is more acute in light of the UK government's initiative to set tighter carbon-reduction targets than are required by EU standards.

To illustrate the trilemma further: nuclear energy may solve the problem of security of supply, but it too comes with extensive capital costs, both in the construction phase and in the decommissioning phase, along with environmental risks, which are all too public. Natural gas is cleaner than existing fossil fuels such as coal, and new gas-fired combined cycle generation facilities are relatively cheap to construct and to run (depending on commodity prices), but now natural gas is imported to the UK via international supply routes that can be subject to suspension through geopolitical fallout.

Against this backdrop, the government has announced proposals to address the energy trilemma and develop a long-term, low-carbon growth-strategy delivery plan for the UK. The proposals are based on increasing investment confidence through the reform of the electricity market, implementing a planning system that will encourage growth, and designing an economic model that is intended to result in no one particular class of party bearing a disproportionate share of the financial risk associated with investing in low-carbon initiatives.

Investment in low-carbon initiatives is perceived as too risky with investors not certain of the likely rate of return for their investment through a combination of market, technology, and policy risks. Investors are wary that the existing major utilities are

the price-setters and can, therefore, pass through the variable price of carbon and gas feedstock into the cost of their power while low-carbon generators will be price-takers and unable to factor such variable costs into their economic model. Moreover, recent economic pressures within different EU member states have caused their governments to revisit their renewables support policies and so investment becomes subject to significant political risk. If the funding gap is to be filled by institutional investors, the investment framework needs to address the risk-averse profile of this type of investor.

The UK government, therefore, proposes to incentivize investment in energy infrastructure by:

- undertaking the widest reform of the electricity market since the 1989 privatization to stimulate investment in electricity infrastructure;
- supporting low-carbon infrastructure and encouraging investment in renewable energy projects;
- providing targeted support for particular technologies
- establishing the Green Investment Bank to facilitate enhanced private sector involvement in infrastructure projects;
- implementing a new and transparent planning regime pursuant to the Localism Bill which is intended to speed up the planning decision-making process for major infrastructure projects.

Electricity Market Reform

The Electricity Market Reform White Paper published on July 12, 2011 (the “EMR”) sets out the government's commitment to *“transform the UK's electricity system to ensure that our future electricity supply is secure, low carbon and affordable.”*

This reform has four key elements:

- implementing long-term contracts for low-carbon energy to provide predictable revenues for investors;
- establishing a carbon price floor to prevent volatile price fluctuations and incentivize investment by reducing uncertainty as to the carbon price;
- introducing an emissions performance standard specifically to regulate the volume of CO₂ that new generating plants are entitled to emit; and
- implementing a capacity mechanism for generators that will support back up power plants and ensure that there is sufficient electricity to meet peak demand.

Long-Term Feed in Tariffs with Contract for Difference (FiT CfD)

Long-term contracts will be the principal tool for incentivizing investment in low-carbon generation by providing greater revenue certainty and insulating investors from price risk, which are intended to increase the rate of investment and lower the cost of capital.

FiT CfDs will be long-term contracts between a low-carbon ▶

generator and a governmental counterparty pursuant to which payments shall be made by the government to the generator when the market price for power sold by the generator is less than a pre-determined strike-price set forth in the FiT CfD and payments shall be made by the generator to the government when the market price for power sold by the generator is greater than the pre-determined strike-price.

Carbon Floor Price

A floor price for carbon will come into effect starting April 1, 2013. The floor price is established by a combination of a tax levy on the use of fossil fuels and the EU ETS carbon price. UK government proposals project that this price floor will begin at around £15.70/tonne of CO₂ rising in a straight line to £30/tonne of CO₂ in 2020 and £70/tonne of CO₂ by 2030. The aim of the floor price is to impose a transparent pre-determined cost on greenhouse gas emissions to disincentivize polluting plants and incentivize investment in low-carbon technologies. The use of these fossil fuels to generate electricity will become liable to new carbon price support rates calculated by reference to the relative carbon content for each fuel (e.g., the carbon price support rate for natural gas will be lower than the carbon price support rate for coal and oil).

Emissions Performance Standard

An emissions performance standard (the “EPS”) will apply to new fossil-fuel generators. The EPS will impose a backstop on the volume of emissions that a new fossil-fuel generator can produce. The EPS will not be applied retrospectively to existing fossil fuel generators except when such generators undergo significant life extensions or upgrades, and will initially be set at 450g of CO₂/kWh. This level will not constrain investment in new gas-fired generating capacity.

Capacity Mechanism

This element of the EMR proposals is the least developed at the moment. The UK government has identified a need for a mechanism that addresses the likely reduction in capacity margins as older plants are decommissioned and new generation (such as nuclear) is still under construction or, in the case of renewables, is intermittent and requires back-up. To a certain extent, the capacity margin can be addressed by non-generation measures, such as intelligent demand-side management, electricity storage, and increased capacity on interconnections with continental Europe. The two alternatives for generation-side measures are likely to be based on either the creation of a strategic reserve or a market-based mechanism for capacity payments.

Carbon Capture and Storage (CCS)

A key element of the UK government’s infrastructure initiative is the focus on CCS. The UK government notes that CCS has the potential to reduce carbon emissions by up to 90 percent —

although this does not take into account the fuel that will be expended in the process of capturing, transporting, and storing CO₂. The UK government has declared a policy to support the cost of four CCS commercial demonstration projects at UK power stations. It was recently announced that a procurement process for the first CCS demonstration project has been cancelled: this was reportedly as a result of a failure to reconcile cost projections for this development with the UK government’s need to set a firm budget for its financial support.

Green Investment Bank

The Green Investment Bank (the “GIB”) is intended to complement the existing policy landscape and demonstrate the Government’s commitment to promoting green growth and ensuring that the UK makes a successful transition to a low-carbon economy by providing solutions to potential market failures that may affect the financing of the green economy and disincentivize green investment. The UK will be the first country in the world to create a bank solely dedicated to facilitating its transition to a green economy. Although strategically aligned with the UK government’s green-policy objectives and initiatives, the GIB will operate at arm’s length to the government and in co-operation with private sector players.

Investment Products

The GIB is expected to offer both equity and debt investment products, including:

- subordinated debt during the construction and/or operational phases of a project to decrease the risk profile of the project and potentially attract other lenders;
- refinancing commitments to refinance existing borrowings to provide longer tenors consistent with the long-term nature of a capital-intensive renewables project;
- equity investment when the opportunities for lending are limited because of the lack of sufficient secured assets; and
- senior lending when there is insufficient commercial bank appetite.

Key Concerns

While FiT CfDs should, in principle, enhance investment in the electricity sector and the renewables market, their success depends on the formulation used to calculate the benchmark strike price and the relevant index on which the market reference price will be based as these two elements form the basis of the contract. Where the strike price is uncompetitive or the market reference price is volatile, investment may not be incentivized. Both the reference price index and the calculation of the strike price remain open issues.

Given the capital-intensive nature of renewable technology, investors need to consider whether non-vertically integrated renewable generators will be able to locate market purchasers for their power at a price that is economic for their particular ▶

renewable project. Since the FIT CfD will eventually replace the Renewables Obligation, which would otherwise have imposed an obligation on power purchasers to acquire a certain proportion of power from renewable sources, the problem of market access may become worse.

Will the imposition of a carbon floor price adversely affect other heavy industries that are not involved in power generation (e.g., steel, chemicals, and aluminium manufacturing or liquefaction processes)? These heavy industries are already bound by emissions trading standards and the imposition of an increasing carbon floor price passed-through into higher energy prices may result in the loss of competitiveness for such UK industries.

Final Thoughts

It seems clear that the government is taking steps to resolve the energy trilemma and encourage investment in low-carbon technologies and energy infrastructure. Despite these steps, however, there are still substantial uncertainties as to how the proposals will be funded and implemented. The government aims to address these uncertainties by introducing legislation in the Parliamentary session next year. Provided the legislative package is stable, clarifies the uncertainties and sets a FIT CfD strike price that is competitive and encourages investment, the message from the government appears to be that investment opportunities in the UK energy sector will very much be on the rise in the future. ■

Three Central and Eastern European Countries Suspended from Kyoto Protocol Carbon Trading

By Casey Hopkins and Andrea Wang

Three Central and Eastern European countries have been recently suspended from international carbon trading for violating Kyoto Protocol emissions reporting rules. Bulgaria was suspended in June 2010 for seven months. Romania was suspended on August 27. The ban will be lifted when Romania has rectified the breach, which is anticipated to take at least six months.¹ The UNFCCC Compliance Committee preliminarily found Ukraine non-compliant with guidelines for national inventory systems on August 25, a finding that was upheld on October 12. The ban will likely remain in effect until the middle of 2012.²

Suspension affects a country's ability to participate in Kyoto Protocol's flexibility mechanisms. The Protocol set quantified commitments for limiting or reducing anthropogenic greenhouse gas emissions in 39 countries that are developed or in transition towards a market economy for the 2008 to 2012 period. To help achieve these commitments in a cost effective way, three flexibility mechanisms were designed. Two project mechanisms—Joint Implementation (JI) and the Clean Development Mechanism (CDM)—allow an investor country to obtain emission credits by investing in projects that reduce or limit greenhouse gas emissions in a host country. A third market mechanism allows for international emissions trading. Eligibility to participate in the mechanisms depends on a country's compliance with the Protocol's methodological and reporting requirements.

Joint Implementation

Mandated under Article 6 of the Kyoto Protocol, Joint Implementation applies only to the 39 Annex I countries with

quantified emissions caps. Developed countries are particularly urged to partner with those transitioning to a market economy.³ Under JI, an investor country transfers technology and provides financing for an emissions reduction project in a host country. The host country benefits from the economic and social development resulting from the project, while the investor gains carbon credits from the emission reductions achieved, termed Emission Reduction Units (ERUs).⁴ JI became operational in 2008. Although Annex I countries could host JI projects prior to that date, ERUs could only be transferred starting that year. Both public and private entities are eligible to develop JI projects, but JI is voluntary and mainly intended for the private sector.⁵

There are two procedures for developing JI projects, with different eligibility criteria. Track 1 is simpler and allows the host country to register projects. Track 2 requires additional checks by placing the Joint Implementation Supervisory Committee in charge of approving projects. The two tracks differ mainly in how rigorously additionality—the requirement that any reduction of emissions resulting from the project is “additional to any that would otherwise occur”⁶—is proved.

An Annex I country can develop a JI project under Track 1 if it satisfies all of the following eligibility requirements:

1. the country is party to the Kyoto Protocol;
2. the country has calculated its assigned amount;
3. the country has set up a national system to estimate greenhouse gas emissions;
4. the country has set up a national registry;
5. the country has submitted the most recent required annual inventory of emissions to the Secretariat; and
6. the country has submitted any supplemental information that the Secretariat may require.⁷

Under Track 1, the host state itself verifies that reductions in emissions are in fact additional to what would otherwise occur. For this reason, some view Track 1 as having less environmental ▶

credibility because proving that projects are additional under this track is subject to the varying standards employed by each country. Upon verification, the host country can issue the appropriate number of ERUs.⁸ To do this, it converts, in its national registry, a portion of the assigned amounts that it holds equivalent to the emission reductions generated by the project into ERUs, and then transfers them from the host country's registry to that of the investor country. No new emission rights are created in the process.

If a host does not meet the above requirements, then verification that reductions are additional must occur through Track 2, which involves an accredited independent entity. Under this procedure, JI project participants submit a project design document to the independent entity, which then determines whether:

1. the project has been approved by the countries involved;
2. the project would result in an emissions reduction that is additional to any that would otherwise occur;
3. the project has an appropriate baseline and monitoring plan; and
4. project participants have submitted documentation on the analysis of the environmental impacts of the project activity.⁹

Note that a host that meets the Track 1 requirements may nevertheless elect to use the Track 2 procedure.¹⁰ Additionally, even under Track 2, the host country may only issue and transfer ERUs if it is a party to the Kyoto Protocol, has calculated its assigned amount, and has in place a national registry.¹¹ So far, only 10 million ERUs have been issued through Track 2, compared to 80 million under Track 1, partly because of greater oversight requirements in the former procedure.

Clean Development Mechanism

Like JI, the Clean Development Mechanism (Article 12) provides emission credits to Annex I countries that invest in emission reduction or prevention projects in another country. In the case of CDM, however, the host country is a developing nation not included in Annex I of the Kyoto Protocol, and the resulting emission credits are called Certified Emission Reductions (CERs).¹² The procedure for CDM is similar to that for JI Track 2, except here, the certifying body is called a "designated operational entity." The designated operational entity's role is to independently evaluate proposed CDM project activities against requirements set out in decision 17/CP.7; verify the emission reductions that have occurred as a result of the project; certify in writing that the project activity achieved the verified amount of reductions; and request for the issuance of CERs equal to the verified amount of reductions.¹³

Similar to JI Track 1, an Annex I country must satisfy the same above six eligibility criteria to be able to use CERs to contribute to compliance.¹⁴ A country is considered to meet the requirements until the enforcement branch of the Compliance Committee has suspended the country's eligibility.¹⁵

International Emissions Trading

The Kyoto Protocol also allows the trading of carbon credits known as assigned amount units (AAUs),¹⁶ which are credits for each country's allotted cap on greenhouse gas emissions. Under Article 17's international emissions trading, the Protocol's third flexibility mechanism, Annex I parties that have difficulty complying with their reduction commitments can purchase AAUs from other Annex I parties that have a surplus. Because AAUs do not represent real emission reductions, their worth on the carbon market depends significantly on their linkage to Green Investment Schemes, which commit the seller to invest the proceeds in projects that will reduce emissions.

International emissions trading is also subject to the above six eligibility requirements: a party is eligible to transfer or acquire AAUs only if all six requirements are met.

The Consequences of Suspension

In the most recent suspension cases, both Romania and Ukraine's 2010 annual submissions were found not sufficiently complete, accurate, and transparent as required by UNFCCC reporting guidelines for national systems.¹⁷ Both failed to meet the eligibility requirement under Articles 6, 12, and 17 of the Protocol to have in place a national system for estimating greenhouse gas emissions and were therefore suspended from participation in the flexibility mechanisms. Suspension has been likened to a freezing of carbon assets,¹⁸ and has different implications for each mechanism.

Least relevant to the three Central and Eastern European countries is Article 12's Clean Development Mechanism. This is so because these countries have generally served as hosts providing a source of carbon credits for other developed Annex I countries rather than investors seeking extra credits. Nevertheless, were they to participate as investors in CDM projects, they would be ineligible to transfer or acquire CERs,¹⁹ and also ineligible to use CERs to contribute to compliance with their overall emission reduction commitments once the suspension is in place.²⁰ Additionally, private and public entities authorized by the countries to participate in Article 12 project activities also could not transfer or acquire CERs while the authorizing country is ineligible to do so.²¹

Suspension would implicate Article 17 international trading of AAUs to a limited degree. Ukraine and Russia have the biggest forecasted AAU surpluses, representing over 75 percent of the global excess.²² Romania, which only enacted legislation to sell carbon credits last year, has yet to sell any of its 300 million spare AAUs.²³ Once suspended, these countries and any legal entities under their authorization will no longer be eligible to transfer or acquire AAUs,²⁴ although future transactions can continue to be negotiated and prepared. If Romania and Ukraine are suspended for the estimated six-month period, they will be reinstated in mid-2012, at which point there will only be a few months left before the Kyoto Protocol expires at the end of the year. This generates a great deal of uncertainty as the value of AAUs after 2012 is yet unknown. ▶

Note, however, that the impact of suspension on the AAU trade is limited because the market is already saturated. The value of AAUs has plummeted from the market peak of around 10 euros per credit in 2008, and Romania is expected to receive a fraction of that price when the trading ban is removed later this or early next year.²⁵ As a result of the financial crisis, industrial powerhouses such as Japan, Spain, and Portugal—traditional buyers of carbon credits—are no longer making large purchases.²⁶ For Ukraine, suspension is unlikely to delay or prevent any AAU sales because the government is not expected to sell any of its surplus over the coming year.²⁷

After preliminary findings about its likely imminent suspension were publicized, Ukraine scrambled to put through a number of carbon transfers. The government handed out over 14 million AAUs to 13 projects under the JI mechanism for emission reductions made before 2008.²⁸ These twelfth-hour transfers are legal under Kyoto Protocol's trading provisions so long as both parties are eligible to enter into the transaction at the time the transfer is made. This is because a transfer of carbon credits is deemed complete once specified steps are taken: a party orders a national registry to issue credits—whether AAUs, ERUs, or CERs—to a specific account; the Secretariat certifies that the parties are eligible to participate in the flexibility mechanisms and that the credits proposed for transfer are valid; and the credits are removed from the transferring account and recorded in the acquiring account.²⁹ The flip side of this bright-line rule is that carbon credits not delivered prior to suspension will likely be delayed and contractual commitments stalled, making it harder for suspended countries to cash in on their Kyoto permit surplus.

Lastly, suspension would affect issuance of Track 1 ERUs, but not that of Track 2 credits, which are verified through an accredited independent entity. This is provided for in both 9/CMP.1 and 11/CMP.1, which stipulate that limitations to transfer “shall not apply to transfers by a Party of ERUs issued into its national registry that were verified in accordance with the verification procedure under the Article 6 Supervisory Committee.”³⁰ The rationale presumably is that an investing entity should get credit for emission reductions that have been independently verified by a third party and should not be penalized for deficiencies in the host country's reporting system. Thus, suspension could mean late delivery of Track 1 ERUs, but will not impact Track 2 transfers.

Traditionally ERUs have traded at a discount to other credits because of a lack of liquidity on the buying side, but more participants are getting comfortable with the trade, leading some to believe that the value of ERUs will rise.³¹ Ukraine is the world's largest supplier of ERUs, having issued about a third of all ERUs to date: around 25 million out of 74 million units.³² It is estimated that suspension could lead to delays in the issuance of 3 million Ukrainian Track 1 ERUs and one million Romanian ERUs.³³

In conclusion, suspension of the three Central and Eastern European countries will have differing effects on the nations' ability

to participate in each of the three flexibility mechanisms. Its effect on CDM is largely irrelevant; its effect on the AAU trade is limited by the fact that relatively little buying is occurring; and its effect on Track 1 ERU transfers is mainly to delay some transactions. The impact on the AAU and ERU trade is mitigated by the relatively short anticipated duration of the suspension and by the legality of last minute transfers in anticipation of suspension. ■

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- 6 Kyoto Protocol to the United Nations Framework Convention on Climate Change, art 6, 1(b), Dec. 10, 1997, 37 I.L.M. 22 (1998).
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- 8 *Id.*, Decision 9/CMP.1, ¶ 23.
- 9 *Id.*, Decision 9/CMP.1, ¶ 33.
- 10 *Id.*, Decision 9/CMP.1, ¶ 25.
- 11 *Id.*, Decision 9/CMP.1, ¶ 24.
- 12 A CER is equal to one metric ton of carbon dioxide equivalent.
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- 14 *Id.*, Decision 3/CMP.1 ¶ 31.
- 15 *Id.*, Decision 3/CMP.1 ¶ 32(b).
- 16 An AAU is equal to one metric ton of carbon dioxide equivalent.
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- 18 Coelho, *supra* note 1.
- 19 U.N. Framework Convention on Climate Change, *supra* note 3, Decision 11/CMP.1, ¶ 2.
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- 22 Ovidiu Posirca, *Kyoto ban could leave Romania with 537 million unsold AAUs*, Business Review, Sept. 5, 2011, <http://business-review.ro/power/kyoto-ban-could-leave-romania-with-537-million-unsold-aau/12203/>.
- 23 Coelho, *supra* note 1.
- 24 U.N. Framework Convention on Climate Change, *supra* note 3, Decision 11/CMP.1, ¶ 2, 5.
- 25 Posirca, *supra* note 22.
- 26 *Id.*
- 27 Garside, *supra* note 2.
- 28 These credits are labeled AAUs because under Ukrainian law, JI projects earn AAUs for emission cuts made before 2008, the start of the five-year Kyoto phase, and ERUs after 2008.
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Legislative and Regulatory Updates

Carbon Prices Near Record Lows: Over the last four months, carbon prices have tumbled nearly 70 percent amid fears that oversupply and lagging economic growth in Europe will drive down demand. On October 19, EU allowance contracts closed below 10 euros, and prices for UN carbon credits hit an all-time low of 6.80 euros. Prices have since remained low, and as of November 2, market prices for December 2011 delivery were €9.69 for EU allowances and €6.60 for UN carbon credits.

EU Plans to Expand GHG Limitations to Aviation Face

Challenge Before IACO: On October 6, 2011, a European Court of Justice Advocate General concluded that the EU's plans to include all flights originating or landing in the EU in the ETS was legal under international law. The opinion is thought to foreshadow the final ruling of the European Court of Justice in a challenge brought by several U.S. airlines, which is expected early next year. However, it now seems likely that the planned January 1, 2012, inclusion of international flights will be delayed pending resolution of the case.

Most non-EU countries have publicly opposed the aviation ETS. In September, 25 countries including the U.S., Japan, China, India, and Russia, filed a Joint Declaration opposing the aviation ETS and threatening to take the matter before the International Civil Aviation Organization (ICAO). In July, the U.S. passed legislation preventing

domestic airlines from participating in the EU ETS, and Russia is currently considering similar measures. Russia has also warned that it may file a formal complaint against the inclusion of aviation in the EU ETS at the next ICAO meeting. In addition recent talks between the EU and China have been unsuccessful, raising the possibility that China will also bring suit challenging the inclusion of its aircraft in the ETS.

Expectations Low for Durban Climate Talks: The final round of U.N. climate negotiations before Durban concluded in Panama on October 7. While important progress was made on a number of measures to assist developing countries and provide for technology transfer, the parties to the Kyoto Protocol remain sharply divided over its future after 2012. There is little optimism that Durban will either result in a new binding global climate agreement or that terms to extend the Kyoto Protocol beyond 2012 will be reached. Instead, it is expected that the parties will turn their attention to framing a plan to create a new global climate regime by 2015.

Australia's Plans for Carbon Tax Move Forward: Australia's lower house has passed a bill that would introduce a carbon tax in 2012 and establish an emissions trading scheme for GHGs by 2015. The Australian Senate has announced its intentions to vote on the bill on November 8. If the bill passes the Senate, 500 of the country's largest emitters will be assessed a carbon tax of A\$23 per ton of carbon dioxide emitted beginning July 1, 2012. ■

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