Energy Committees Newsletter

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MESSAGE FROM THE EDITOR

Adam T. Sherwin, Esq.

Thank you for reading this edition of the Energy Committees' collaborative newsletter! As we get closer to the November elections, matters of energy law and policy will almost certainly get more attention by candidates, public interest groups, and the media. This newsletter includes articles addressing many topics in these important areas. In particular, the increased demand for transmission across the country is one of these pressing matters. Read "Navigating the Legal Barriers to Microgrids" by Max Fine and Dan Fredrickson and "FERC Order 1000 and Public Policy Transmission Projects" by James Heidell and Sandra Ringelstetter Ennis for an extensive analysis on the future of transmission. In addition to the increased demand on transmission, renewable energy sources continue to face numerous legal hurdles. "Hydraulic Fracturing as a Subsurface Trespass" by Barclay Nicholson and Brian Albrecht is a must read for anyone interested in legal issues confronting natural gas hydraulic fracturing. Read K.K. DuVivier and Ian London's "A Tale of Two Projects: NEPA's EIS v. Mitigated FONSIs" for a look at an alternative means of streamlining the approval process for renewable energy projects.

To support renewables with these challenges and to address climate change, lawmakers will certainly continue to pass legislation aimed at dealing with these important matters. "Carbon and the Constitution: Barriers to Life-cycle Assessment Threaten the Credibility of State Bioenergy Policies" by Jody M. Endres and Daniel Szewczyk and "Triangulation: California's Low Carbon Fuel Standard, Cap-and-Trade, and the Commerce Clause" by Keith M. Casto and Bradley M. Tanner discuss a recent California case over the nation's first low carbon fuel standard and the legal challenges involved with this legislation. For further information on any of these topics, please contact our contributing authors. We hope this edition of the Energy Committees' Newsletter provides an excellent overview on some of the important issues that will be part of our country's energy future.

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Adam T. Sherwin, Editor

This newsletter is a cooperative effort of the following committees: Energy and Environmental Markets and Finance; Energy and Natural Resources Litigation; Energy and Natural Resources Market Regulation; Energy Infrastructure and Siting; Hydro Power; Oil and Gas; Petroleum Marketing; Renewable, Alternative, and Distributed Energy Resources; and the Special Committee on Nuclear Power.

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NAVIGATING THE LEGAL BARRIERS TO MICROGRIDS

Max Fine and Dan Fredrickson

The Need for Microgrids

The electric grid in the United States is an integral part of the United States's infrastructure. We depend on the grid to deliver electricity in a reliable and secure manner to power our homes and businesses, move our transit systems, and keep our society running in countless other areas of life.

However, the electric grid is aging, threatening the reliability of electricity service. The Lawrence Berkeley National Laboratory (LBNL) reports that 80 percent to 90 percent of all grid reliability issues begin at the distribution level of electricity service, which results in large part because of insufficient infrastructure to meet demand. In fact, in 2009 the American Society of Civil Engineers (ASCE) graded the U.S. grid a D+, citing a lack of investment in new transmission and distribution capacity. The ASCE estimates that the resulting power outages and power quality disturbances on the grid cost the U.S. economy between $25 billion and $180 billion annually.

There is a strong need to dramatically shift the existing grid of the regional electricity transmission to distribution model (the "macrogrid") to one that is more localized and thus better capable of meeting demand in a reliable and secure manner. While significant investment at the macrogrid level may be one solution, another is to focus investment on the distribution level by utilizing microgrids.

Microgrids are localized systems of electric generation and distribution that reduce demand and "wear and tear" on the macrogrid. Unfortunately, the regulatory framework that governs a state's electric utility industry was not developed in anticipation of an abundant number of community-based generation and distribution systems.

What Are Microgrids?

The LBNL defines a "microgrid" as a localized integrated energy system consisting of distributed energy resources and multiple electrical loads operating as a single, autonomous grid either in parallel to or isolated ("islanded") from the existing utility power grid. The most applicable markets for microgrids are college campuses, corporate headquarters, hospitals, and military bases, where campus-like facilities consume large amounts of energy.

Microgrids allow these facilities to manage their own energy sources and achieve greater control in meeting energy demands. Microgrids are often cheaper than traditional power plants, more environmentally friendly, and experience less operational downtime and greater operating efficiency. Many advocates also highlight that the flexibility and operating efficiency of microgrids can enhance their ability to integrate intermittent renewable generation sources (i.e., wind and solar). Perhaps the most advantageous feature of a microgrid is its ability to separate and isolate itself—known as "islanding"—from the utility's distribution system during brownouts or blackouts. These islanded systems ensure secure power to their users while the power grid is down.

Microgrids are likely to become an important and integral part of the U.S. electric grid. According to Pike Research, by 2017 the microgrid market will grow by 164 percent; however there are significant regulatory and legal barriers that continue to hinder their development today. The remaining portion of the article provides you with a checklist of issues to review to determine how to mitigate legal barriers as you move forward on a proposed microgrid project.

Checklist on Legal and Regulatory Barriers to Deploying Microgrids

Legal and regulatory uncertainty presents a barrier to the deployment of microgrids. In part because of the monopoly status of electricity providers and because existing regulations pay little attention to microgrids specifically, it is difficult to predict how a microgrid project will be treated in a specific jurisdiction. In fact, as research from Douglas King of Carnegie Mellon found, many state regulators have concluded that it is unclear how microgrids would be regulated under their own state's law.

The viability of a given microgrid within your state's legal and regulatory structure depends on an assortment of issues, such as the microgrid's ownership structure, which types of customers would receive service from the microgrid, and how profits from those services are earned and distributed. To best proceed with a microgrid project, it is highly recommended that you make a checklist to determine the plausibility of a project in your respective state. Below are common legal and regulatory issues that attorneys should include in their checklist to determine the viability of a microgrid within that state. Please note that this article assumes that the proposed project does not connect to the transmission side of the grid and thus is not regulated under the Federal Energy Regulatory Commission's (FERC) jurisdiction.

1. Determine What Constitutes a Public Utility in the Jurisdiction

The feasibility of a microgrid project may depend in large part on how a particular jurisdiction defines a public utility. For the most part, avoiding the classification of public utility should be preferred for a variety of reasons. Most notably, if a microgrid is classified as a public utility then it is unlikely to be permitted to operate in the defined service territory of the incumbent utility. According to a 2010 report by Alisha Fernandez and Seth Blumsack of Penn State University, the largest regulatory barrier to the development of microgrids is state public utility commissions' belief that the microgrid network infringes upon the monopoly territory of the incumbent utility. However, even in those situations where the microgrid would not be outright prohibited, the classification of public utility would subject the project to extensive and costly regulation.

2. Determine the Most Appropriate Microgrid Ownership and Service Model

Identify the participants of the project. By establishing the potential ownership and service structure of the microgrid project, you create an opportunity to better assess the regulatory and legal barriers of your respective project—including whether or not public utility status would apply. In a recent publication, the New York State Energy and Research Development Authority (NYSERDA) presented seven ownership and service models. Those ownership and service models are highlighted below:

A. ***Vertically Integrated Utility Model*****:** The electric utility owns the microgrid distribution lines and generation technologies operating on the system, providing energy services to participating customers.

B. ***Unbundled Utility Model*****:** The electric utility owns and maintains the electric distribution facilities serving the microgrid, which provides energy, while generation technologies are owned by participating customers or third parties.

C. ***Landlord/Campus Model, Type 1*****:** A single non-utility owner operates the system and installs private wires and generation technologies on-site, supplying power to multiple buildings also owned by the landlord-operator. Buildings and streets have the same owner and there are no previously unaffiliated parties receiving service from the microgrid. The system's wires do not cross a public way or utility franchise.

D. ***Landlord/Campus Model, Type 2*****:** This model is the same as Type 1, but wires cross a public way or utility franchise.

E. ***Landlord/Campus Model, Type 3*****:** This model is also the same as Type 1, but wires may cross a public way/utility franchise *and* previously unaffiliated neighboring customers may voluntarily join the microgrid and be served under contract.

F. ***Joint Ownership/Cooperative*****:** Multiple individuals or unrelated firms collectively own and operate the microgrid to serve their own electric and/or thermal energy needs. Other customers may voluntarily join the microgrid and be contractually served. The system's wires may cross a public way/utility franchise.

G. ***Independent Provider*****:** An independent non-utility firm owns and manages the microgrid and sells energy to multiple unaffiliated customers. This business model is strictly commercial. The independent owner/operator produces primarily for sale to others and not for its own consumption. The system's wires may cross a public way/utility franchise.

The feasibility of each of these models will vary based on the state. The most favorable models, according to the survey conducted by King, are the Utility and Landlord/Campus Type 1 ownership models. The Utility model consists of an incumbent regulated utility in its own service territory, which will raise few regulatory hurdles beyond those that already apply to the utility. The Landlord/Campus Type 1 model describes an electric system that is located entirely on private property in which no previously unaffiliated customers are serviced. Because many states provide statutory exemptions from regulation as public utilities for systems that are located entirely on private property (i.e., wires do not cross public ways), Landlord/Campus Type 1 microgrids are subject to fewer prohibitive regulations.

3. Determine How the Microgrid Will Connect to the "Macro" Grid

The manner in which the microgrid will connect to the larger electric grid—if at all—sheds light on how it will be viewed by regulators. Microgrids may be (1) islanded from the grid, (2) interconnected to the utility's distribution system, or (3) interconnected at transmission.

Microgrids that are permanently islanded are the least problematic from a regulatory point of view because there is no interaction with the grids. However, a permanently islanded microgrid may be less beneficial for participants because it cannot rely on the utility in times of excess demand or system failure.

Microgrids that interconnect with the distribution system face additional hurdles because they are subject to interconnection standards that are established by the state's public utility commission and enforced by the local utility company. Moreover, interconnection at the transmission level indicates participation in the wholesale market, in which case the project will likely be subject to FERC regulation.

4. Determine Whether the Microgrid Can Be Considered a Qualifying Facility

In order to encourage energy efficiency and conservation, the Public Utility Regulatory Policies Act (PURPA) created qualifying facilities (QFs), which are either cogeneration or small power production (primarily renewable energy sources) facilities. These types of facilities receive special rates and regulatory treatment through FERC. Additionally, the PURPA also delegates substantial authority to the states to set actual QF requirements, which typically include limitations on size of generating capacity, fuel-use criteria, and operating and efficiency standards.

Meeting the requirements for QF status could be very advantageous for a microgrid project. QFs enjoy benefits under federal, state, and local laws which generally include (1) the right to sell energy or capacity to a utility, (2) the right to purchase certain services from utilities, and (3) relief from certain regulatory burdens such as the Public Utility Holding Company Act, Federal Power Act, and state public utility laws concerning rates, finances, and structuring of utility companies.

Each state sets its own QF requirements, so it is essential to determine what the specific requirements are in your microgrid project jurisdiction.

5. Research and Ensure Compliance with Federal and State Environmental Laws

Microgrid systems that will require permits from state and federal authorities include those systems that use thermal power production and combust fossil fuels, biomass, or other renewable biofuels producing air emissions. Unless a source qualifies for an exemption, a permit is required. The need for a permit will depend on the features of a project and emissions levels.

6. Additional Issues to Note

Review the State's Interconnection Policy

Interconnection is the physical link of the generation source to the electric grid. States establish interconnection rules, which apply to utilities, to create a uniform process of technical requirements for distributed generators to connect to the grid. The interconnection standards for a microgrid may differ from the process of interconnecting a single form of distributed generation. The total generating capacity of the microgrid may affect the interconnection requirements. If your state does not have a legal limit on the amount of distributed generation that could be interconnected, the utility authority over the technical requirements could establish a de facto limit through the imposition of expensive grid protection schemes or limitations on the system's operating characteristics.

Property Law—Franchises and Lesser Consents and Certificate of Public Convenience and Necessity

If the microgrid requires the use of public ways to deliver its power, the developer must be granted consent by the presiding municipal authority in the form of a franchise or in some lesser form of consent. In addition, operation of a microgrid under a franchise requires approval from the state utility commission in the form of a certificate of public convenience and necessity (CPCN), which is essentially the state's utility commission providing authorization to the developer to construct new generating stations or electrical distribution facilities. A CPCN may also be required if the developer plans to sell power directly to retail customers. Generally, the developer obtains the CPCN through a public hearing with the state utility commission.

Fortunately, in most cases a lesser form of consent will suffice when a microgrid proposes to occupy public ways to provide service. In most states, operation under a lesser form of consent will not trigger state utility commission approval like the CPCN.

Conclusion

Microgrids have the potential to play an integral role in enhancing energy production in the United States. They offer significant advantages in terms of cost, reliability, and sustainability, but specific regulatory and legal guidance is necessary to accelerate the deployment of microgrids into market.

The absence of specific microgrid regulation should not—in and of itself—deter you or your client from inquiring in building a microgrid project. Rather, we hope that the brief guidance provided here will give you the tools necessary to determine whether or not a microgrid project is feasible in your particular jurisdiction. Defining your client's project and cross-checking it with your state's laws and regulations will highlight potential barriers that might hinder the progress of the project and enable you and your client to make an informed decision about the potential risks. For more information, please see NYSERDA, "Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State" and Douglas E. King, "The Regulatory Environment for Interconnected Electric Power Microgrids: Insights from State Regulatory Officials."

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FERC ORDER 1000 AND PUBLIC POLICY TRANSMISSION PROJECTS

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Background

Federal Energy Regulatory Commission (FERC) Order 1000, issued on July 21, 2011, addresses three fundamental reforms affecting transmission planning: regional planning reforms, cost allocation reforms, and non-incumbent developer reforms (Docket No. RM10-23-000). Moving beyond the regional planning provisions in FERC Order 890, the new order requires each public utility transmission provider to consider transmission needs driven by public policy, and expands on interregional coordination requirements. Order 1000 is widely viewed as an opportunity to fund more transmission projects associated with renewable resources. In this paper we provide a high-level summary of FERC Order 1000 as it relates to the issues of public policy benefits and cost allocation.

FERC's New Six Cost Allocation Principles

In Order 890, FERC outlined nine principles that must be incorporated in the transmission planning process: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects (Docket No. RM05-25-000). Order 1000 addresses cost allocation in greater detail. As in Order 890, FERC shied away from a one-size-fits-all approach in Order 1000 and did not take a prescriptive approach with respect to specific cost allocation methodologies. The commission left it to the regional entities to go through an appropriate process involving stakeholders to adopt a cost allocation methodology consistent with the following six principles (Docket No. RM10-23-000, § 586).

1. The costs must be allocated "in a manner that is at least roughly commensurate with estimated benefits." The benefits include reliability, production cost savings, congestion relief, and meeting public policy requirements.
2. "Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities."
3. If a benefit threshold is established for determining which projects have net benefits, that threshold should not be higher than 1.25, absent sufficient justification.
4. Costs for regional transmission projects cannot involuntarily be allocated to other transmission regions.
5. The methods for cost allocation, determining benefits, and determining beneficiaries "must be transparent with adequate documentation to allow a stakeholder to determine how they were applied . . ."
6. Different cost allocation methods can be used for different types of transmission projects. For example, the transmission entity has the option, but not the requirement, to establish different cost allocation mechanisms in their tariff for projects designed for reliability versus projects associated with public policy requirements.

Compliance Requirements for the Public Policy Provision

Utilities and Independent System Operators (ISOs) are in the process of developing filings to meet the October 11, 2012, compliance requirements related to regional planning processes and cost allocation requirements. Most ISOs are in the process of holding stakeholder meetings based upon groundwork laid in Order 890. Stakeholders may want to simplify the compliance filing by applying the cost allocation procedures developed for Order 890 for the new application to public policy projects. However, prior to taking the "simple" path, a number of issues should be considered.

First, while the FERC has shown significant latitude in approving different cost allocation schemes, the common denominator is that there needs to be broad consensus among the regional participants that the cost allocation process is reasonable. Some regional entities will need to expand the nexus of stakeholders to more broadly encompass the state policymakers and regulators. Second, the beneficiaries of transmission related to public policies such as renewable portfolio standards (RPS) are more likely to be delineated by state boundaries. Third, while Order 1000 requires that costs be allocated commensurate with benefits, the measurement of public benefits is not defined in the order. The process of defining benefits may be controversial. It is not clear that there is regional agreement related to evaluation of public policy benefits.

Public Policy Benefit Calculation Issues

There are a number of high-level issues regarding how to structure the public benefits calculation. These issues include:

- How broad should the definition of a beneficiary be, especially with regard to the determination of who is shielded from the involuntary assignment of costs?
- What is the weight of the cost-benefit analysis in deciding amongst competing projects that all meet the cost-benefit threshold test?
- What is the universe of alternatives that needs to be considered in the assessment of whether a transmission solution is the least-cost approach to achieving the policy?
- How broadly can the future scenarios of likely public policy be defined and does the likelihood need to be part of the calculation of benefits?
- What is the time horizon used to evaluate the associated public policy benefits and should end effects be incorporated into the analysis?
- What is the appropriate discount rate to use and should reliability and public policy benefits have different discount rates?
- How are externalities treated in the calculation?
- How are difficult-to-quantify public costs such as changes in mortality rates for a person or an endangered species measured?
- What is the threshold for no or de minimis benefits to a transmission payer?

How these issues are framed and how the analysis is performed can dramatically alter any results of cost-benefit calculations. Framing the benefits analysis will not start from a blank slate. Federal agencies have dealt with a number of these issues in the analysis of the economic impact of environmental regulations and states have dealt with some of these issues as part of integrated resource planning requirements. The challenge will be in combining these precedents in a manner acceptable to the stakeholders.

Public Policy Benefit Calculation Components

The benefits associated with meeting federal and state environmental regulations and state RPS could potentially incorporate a broad spectrum of issues including:

Access to Renewable Resources

A number of transmission project proposals involve connecting remote renewable resource-rich zones with load centers. The net benefits of these projects need to be compared with potential alternatives including construction of renewables closer to load centers, distributed renewable resources, energy efficiency, and reforming electricity pricing. The analysis becomes more complex if it includes externalities such as impact on view corridors, endangered species, critical habitat, human health, and water use issues.

Reduction of Greenhouse Gas Emissions (GHG)

The complications with GHG emission reductions calculations are associated with the definition of the alternative(s) and value of each lb/ton of reduction. Agreement on what resources are actually being displaced can be complex. The process of comparing the benefits of alternative approaches to transmission, as well as amongst competing transmission projects, will be meaningless if inconsistent valuation assumptions are used.

Lower Air Emissions and Public Health Benefits

The inclusion of public health benefits that extend beyond what is addressed in U.S. Environmental Protection Agency standards as well as the calculation of those benefits will have to reflect the perspectives of the relevant stakeholders.

Economic Development

Analyses of the economic value of the green economy and green jobs initiatives have been controversial. An additional complication is identifying the geographic boundaries for calculation.

Fuel Diversification

The value of the diversification of generation sources can be evaluated in the context of managing volatility in overall electric prices, minimization of shocks from fuel supply issues, and lower costs for a fuel based upon reduced demand ("Valuing Fuel Diversity in Power Markets," by Graham Shuttleworth and Sean Gammons, NERA Economic Consulting).

Cost Allocation Including Public Policy Benefits

Several ISOs have FERC-approved cost allocation methodologies that explicitly address projects associated with reliability and market efficiency. The ISOs will need to consider whether these approaches comply with FERC Order 1000 and whether the methodologies are applicable to projects justified based upon public policy. FERC has been silent on the answer to these questions in recent rulings on transmission cost allocation. For example, FERC recently reaffirmed Midwest ISO's transmission planning process, which includes a new category of transmission projects called "multi-value projects" (MVP) (FERC News Release: Oct. 20, 2011, Docket No. ER10-1791-001). An MVP is defined as a transmission project that is "determined to enable the reliable and economic delivery of energy in support of documented energy policy mandates" or that addresses multiple reliability and/or economic issues affecting multiple transmission zones. The costs of transmission projects that meet the criteria of an MVP are eligible for 100 percent regional allocation. FERC states that its approval "does not address whether any further modifications may be required in order to comply with the requirements of Order No. 1000."

In similar fashion, FERC reaffirmed the Southwest Power Pools (SPP) highway/byway cost allocation methodology (Order on Rehearing, issued Oct. 20, 2011, Docket No. ER10-1069-001). Under the highway/byway methodology, costs are allocated to SPP member utilities based on the voltage of a new transmission facility.

Both the Midwest ISO and SPP cost allocation methodologies allocate the costs of "public policy" projects regionwide. And although FERC has not discussed compliance with Order 1000, one indication of FERC's leaning on this issue may be the following statement from the SPP order: "A strong regionally integrated transmission network provides benefits to all that are interconnected to it." To the extent that states have different public policies related to renewable resources, there may be new disagreements regarding whether the currently approved cost allocation approaches are consistent with the Order 1000 directive that the cost allocation is commensurate with the benefits.

Summary

FERC Order 1000 is part of the evolution of reshaping the wholesale power markets. The requirement to include a new class of benefits related to public policy goals in the regional evaluation of transmission projects has the potential to increase the share of renewable generation in the U.S. electricity production mix. We anticipate that there will be significant controversy related to both defining the calculation of public benefits and determining the appropriate cost allocation for transmission projects justified on the basis of public benefits. It will require a significant effort to define how to calculate public policy benefits, determine how those benefits should be allocated among the market participants, and design the associated cost allocation approach.

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TRENDS Now in New Electronic Format!

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Beginning with the September/October 2012 issue, *Trends* will become an electronic-only publication for Section members.

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HYDRAULIC FRACTURING AS A SUBSURFACE TRESPASS

Barclay Nicholson and Brian Albrecht

Hydraulic fracturing activities continue to rise and are at the center of much debate and litigation focusing on the potential health risks associated with the process. But an emerging issue with fracturing activities, and one that only the Texas courts have addressed with any significance, is whether hydraulic fracturing activities can, or should, lead to actionable subsurface trespass claims.

The Texas Supreme Court has decided a handful of cases dealing with subsurface trespass claims over the years, but only one of those cases, *Coastal Oil v. Garza*, 268 S.W.3d 1 (Tex. 2006), presents subsurface trespass as it relates specifically to hydraulic fracturing. However, the Texas Supreme Court's opinions in the other subsurface trespass cases provide valuable insight to the competing interests involved in the issue, and help to inform the *Garza* decision.

Manziel

In 1962, the Texas Supreme Court considered subsurface trespass in the context of a secondary recovery operation in *Railroad Comm'n v. Manziel*, 361 S.W.2d 560 (Tex. 1962). The plaintiff landowners claimed that the subsurface injection of water into an adjoining tract was a trespass that would result in premature flooding of their subsurface and damage their producing wells. The plaintiffs filed suit against the Texas Railroad Commission (RRC), the state's regulatory agency for oil and gas, which had issued an order permitting the defendants to drill and inject water in their well as part of secondary recovery efforts. The trial court sided with the plaintiffs, cancelling the RRC's order and enjoining the injection of the water. The judgment was appealed directly to the Texas Supreme Court.

The Texas Supreme Court examined cases "covering almost every aspect of the oil and gas industry" where the plaintiff claimed damage to or encroachment on a subsurface estate and found only one situation in which an injunction was granted on a trespass theory: when there is a continuing physical invasion by drilling across lease lines. *Id.* at 567. The court then considered the impact and importance of hydraulic fracturing activities and stated that secondary recovery operations should be encouraged. The court reversed the trial court's judgment, dissolving the injunction and holding that when the RRC "authorizes secondary recovery projects, a trespass does not occur when the injected, secondary recovery forces move across lease lines, and the operations are not subject to an injunction on that basis." *Id.* at 568.

Garza

In 2006, the Texas Supreme Court decided *Garza*, in which the plaintiff leased the mineral rights in his land to Coastal Oil and Gas Corp. (Coastal). Coastal owned the mineral estate in an adjacent tract, and engaged in hydraulic fracturing on both tracts. The plaintiff filed a suit in trespass, claiming that Coastal's fracturing activities invaded the reservoir below his tract and caused substantial drainage of gas.

However, the Texas Supreme Court avoided directly ruling on the issue of whether hydraulic fracturing activities could result in an actionable subsurface trespass claim. Instead, the court declined to decide that "broader issue" and stated that an actionable trespass claim requires an injury, and that the plaintiff's only injury—the drainage of gas from his subsurface – was precluded by the rule of capture. According to the court, the rule of capture only gave the plaintiff the right to capture the gas beneath his tract, as opposed to ownership of the gas itself. With no actual damages, there could be no trespass.

The concurring *Garza* opinion, authored by Justice Willett, went a step further, arguing that instead of it being no "actionable trespass" as the majority found, it was no trespass at all, and plaintiffs could instead bring such suits in negligence. Willett "would end definitively any lingering flirtation of Texas law with equating hydraulic fracturing with trespass," and "say categorically that a claim for 'trespass-by-frac' is nonexistent in either drainage or nondrainage cases." *Garza*, 268 S.W.3d at 29. Throughout his opinion, Willett cited the importance of oil and gas to economy and industry of Texas.

The *Garza* dissent took the position that, until the issue of whether the hydraulic fracturing activities amounted to a subsurface trespass was decided, Coastal's fracturing into the plaintiff's tract must be considered an illegal trespass. And, as Coastal conceded, the rule of capture only applies to gas obtained legally; thus, the rule of capture should not preclude the plaintiff's trespass claim.

FPL

In the 2011 case *FPL Farming Ltd. v. Envtl. Processing Sys., L.C.*, 351 S.W.3d 306 (Tex. 2011) decided by the Texas Supreme Court, FPL, which owned two tracts of land used for rice farming, sued Environmental Processing Systems (EPS), which operated a wastewater injection well on land adjoining FPL's tracts. EPS had a permit from the Texas Commission on Environmental Quality to drill and operate its well. FPL alleged that the injected wastewater likely migrated onto its property and contaminated its water supply, and filed suit based on subsurface trespass.

FPL lost in a jury trial and appealed. The appellate court did not address the merits of the trespass claim, and instead relied heavily on *Manziel* in holding that FPL could not recover because the wells were authorized by EPS's permit.

But the Texas Supreme Court did not give the same deference to the permit, stating that "a permit is not a get-out-of-tort-free card." *Id*. at 311. The court made clear that it was not deciding "whether subsurface wastewater migration can constitute a trespass, or whether it did so in this case," and reversed the court of appeals' judgment and remanded. *Id*. at 315.

Lessons from the Texas Supreme Court

In reviewing the *Garza* majority opinion, concurrence, and dissent, the court's concern with the realities of hydraulic fracturing is evident. The majority opinion referred to numerous amicus curiae briefs filed by the RRC and various organizations and companies "from every corner of the industry," and noted that all opposed liability for hydraulic fracturing, "almost always warning of adverse consequences in the direst of language." *Garza*, 268 S.W.3d at 16–17. Justice Willett's concurrence refers to oil and gas as the "muscle" of Texas, *id.* at 27, and that imposing liability on fracturing activities would result in "exorbitant costs on society." *Id*. at 30. And the dissent, while it argued for a finding of liability, proposed that courts should weigh the claim and the interests involved and allow such equitable considerations to influence the assessment of damages. Additionally, the dissent was influenced by a practical concern for the rights of unsophisticated individuals who own small parcels of land and are unlikely to utilize such remedies as self-help and pooling; the majority's opinion reduces incentives for operators to lease from such property owners. The court similarly deferred to the importance of hydraulic fracturing in its *Manziel* opinion over 40 years earlier. Clearly the impact of hydraulic fracturing activities is at the front of the Texas Supreme Court's mind.

And reviewing *Manziel*, *Garza*, and *FPL* together provides further valuable insights, specifically as to when a subsurface invasion based on hydraulic fracturing activities can constitute an actionable trespass.

First, the court has suggested that a subsurface invasion resulting in actual damages could constitute an actionable trespass; the *Garza* court noted that the plaintiff did not "claim that the hydraulic fracturing operation damaged his wells or the Vicksburg T formation beneath his property," damages which would apparently be recoverable. *Garza*, 268 S.W.3d at 13. Additionally, comparing the *Manziel* and *FPL* decisions provides evidence that actual damages could lead to an actionable trespass. *Manziel* declared that it is not a trespass when injected, secondary recovery forces move across leased lines if the RRC authorized the project, while *FPL* declared that the court of appeals was in error in determining that because the Texas Commission on Environmental Quality permitted the injection wells, there was no trespass. While these are seemingly contradictory, the *Manziel* decision only authorized *movement across leased lines* of secondary injected forces, as opposed to authorizing any injurious movement of the forces. Additionally, the *Manziel* court explicitly stated that it was not granting injecting operators a "protective cloak," and the *FPL* ruling held that a permit does not preclude all liability for trespass. In both decisions, the court seems to have left the door open for an actor to be found liable for subsurface trespass when actual damages result.

Second, the court has suggested that an actionable trespass may be based only on nominal damages if the plaintiff retains a possessory interest in the mineral rights. In *FPL*, the court characterized its *Garza* opinion as holding that the plaintiff could not sue for trespass based on nominal damages because he was not in possession of the mineral rights. The *FPL* court pointed to language in *Garza* stating that a trespass against a possessory interest "does not require actual injury to be actionable and may result in an award of nominal damages." *Garza*, 268 S.W.3d at 13 n.36.

Conclusion

Outside of Texas, where hydraulic fracturing activities are not as prevalent and courts have yet to consider how these activities relate to claims of subsurface trespass, courts can look to the Texas Supreme Court's opinions for guidance. As the *Garza* court's internal debate illustrates, the impact of hydraulic fracturing and its importance to states' economies are sure to be considered by future courts in considering whether to impose liability on fracturing activities, especially in absence of actual damages.

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Tree Planting Events

The Section has undertaken a five-year project with the goal of planting a million trees by 2014. As part of that effort, the Section is sponsoring local tree plantings this spring in thirteen locations around the country. If you live in one of these cities, we strongly encourage you to get out and help with a project—have some fun as well as make a lasting and tangible contribution to your community. For details please visit www.ambar.org/EnvironTrees.

If you can't plant a tree in person, please consider making a contribution to one of the Section's partner tree organizations. The Section's One Million Trees Project will get credit for one tree planted for every dollar donated through the Section website.

For current tree planting events or to make a donation to one of our project partners, please visit

www.ambar.org/EnvironTrees

A TALE OF TWO PROJECTS: NEPA'S EIS V. MITIGATED FONSIS

K.K. DuVivier and Ian London

The National Environmental Policy Act (NEPA) poses a major burden for developers whose projects depend on federal approval. NEPA compliance through an environmental impact statement (EIS) is time-intensive and may still result in cost-prohibitive litigation against the developer. For project opponents, the years of litigation are no less expensive and may still result in the project proceeding as originally proposed.

The Council on Environmental Quality recently affirmed its support for an alternate solution: mitigated "findings of no significant impact" or "mitigated FONSIs." 76 Fed. Reg. 3843 (Jan. 21, 2011). Under a mitigated FONSI, federal agencies can fully comply with NEPA in most projects by compiling an environmental assessment (EA), the EIS's customarily less costly cousin. The EA then conditions federal approval on incorporation of certain mitigation measures, which reduce a project's impacts below the "significant impact" threshold.

Renewable energy projects would appear to be perfect candidates for the mitigated FONSI course of action. Many of these projects' adverse environmental impacts should be inherently mitigated by tangible environmental benefits, such as the reduced CO_2 emissions and fuel transportation costs associated with taking a fossil fuel-oriented power plant offline.

Yet, many of the most successful examples of mitigated FONSI use involve projects without renewables' inherent mitigating benefits. In two recent examples, the U.S. Army Corps of Engineers used a mitigated FONSI to issue a Clean Water Act permit (1) authorizing a developer to fill 40 acres of wetlands for a residential subdivision in *O'Reilly v. U.S. Army Corps of Engineers*, 477 F.3d 225 (5th Cir. 2007) and (2) authorizing road and bridge construction adjacent to navigable waterways in *Audubon Soc'y of Cent. Ark. v. Dailey*, 977 F.2d 428 (8th Cir. 1992).

One of the most salient examples of mitigated FONSI use is the case of *Ohio Valley Envtl. Coalition v. Aracoma Coal Co.*, 556 F.3d 177 (4th Cir. 2009). In *Aracoma Coal*, three coal mining companies sought to open a mountaintop removal (MTR) mining project in the hills of West Virginia. In contrast to traditional underground mining methods, MTR involves blasting up to 400 feet of mountaintop rock to access the underlying coal seams. The blasting greatly expands the waste material, known as "overburden" or "spoil." To get the spoil out of the way, mining operators dump it into lower lying areas near the mine, often at the headwaters of streams. The spoil can bury the stream, and minerals in it can leach acidic chemicals into areas located further downstream. As proposed, the MTR project would have affected 23 valleys and 13 miles of streambed.

Because the project involved streambeds and releasing chemicals into waterways, the mining companies were required to secure Clean Water Act permits from the U.S. Army Corps of Engineers. The Corps, in turn, was required to perform NEPA analysis before issuing the permits. Ultimately, the Corps performed an EA. Generally speaking, the mitigation provisions in the permits required the companies to protect the quality of existing streams where possible; take steps to restore streams damaged by the project; and provide new streambeds where the damage would be unmitigable or unavoidable.

The Corps found that, provided the companies complied with the mitigation provisions, the project would have no significant impact on the environment. The Fourth Circuit agreed, upholding the Corps' decision as a valid use of the mitigated FONSI.

Objectively speaking, the MTR project in *Aracoma Coal* entailed filling numerous valleys and streams with mining overburden for the purpose of extracting a mineral that ultimately emits significant quantities of CO_2 and other air pollutants in the generation of electricity.

Contrast the case of *Aracoma Coal* with the case of Cape Wind. Cape Wind is a proposed wind farm almost five miles offshore of Cape Cod, Massachusetts. As proposed, Cape Wind would contain 130 wind turbines that are approximately 440 feet tall. Its overall footprint would be 24 square miles.

The Cape Wind project has required approval under a myriad of federal, state, and local laws. This article will focus purely on Cape Wind's path through NEPA. Cape Wind's proponents first sought a Corps permit in 2001. As the initial lead agency, the Corps prepared a draft EIS in 2004. This EIS was never finalized. In 2005, pursuant to the Energy Policy Act of 2005, the Department of the Interior took over as lead agency. DOI initiated its own NEPA analysis, releasing a draft EIS in 2008 and a final EIS in 2009. DOI's record of decision followed in 2010.

Cape Wind obtained its final federal permits in January of 2011. Nevertheless, lawsuits continue to buffet the project from all sides. In July 2011, the Wampanoag Tribe sued over the record of decision, alleging that the current DOI agency responsible for the project, the Bureau of Ocean Energy Management (BOEM), failed to adequately consider the cultural significance of Nantucket Sound in approving the project. This is only one of many legal challenges Cape Wind has faced.

Cape Wind first sought federal approval in 2001, and over a decade later, it is still on hold. By contrast, the *Aracoma Coal* project was first submitted to the Corps for approval in 2005, and the Fourth Circuit upheld the Corps' approval in 2009—going from proposal to resolution at the federal circuit court level in roughly four years.

Some of the time discrepancies can be blamed, of course, on Cape Wind's unique setting and complex permitting requirements. Renewable projects are also caught in a cycle of additional permitting time constraints because they are first of a kind, so they cannot benefit from categorical exclusions or other shortcuts conventional projects enjoy.

But speaking broadly, the MTR project and Cape Wind both have extraordinarily significant impacts on the environment. And while Cape Wind would reduce negative environmental impacts elsewhere by offsetting the need for fossil-fuel powered electricity, *Aracoma Coal* inherently results in using more coal as an energy source.

Without taking a position on the wisdom of approving or executing the *Aracoma Coal* or Cape Wind projects, this article's intent is merely to draw attention to the divergent experiences of the proponents of these two projects. Why should one be completed in four years, while one is still bogged down in litigation over a decade later? One possible answer is the various lead agencies' choices of paths through NEPA.

Using the mitigated FONSI, the Corps was able to usher a massive MTR project through NEPA in roughly four years. In exchange, the mining companies agreed to a set of mitigation provisions not unlike those commonly found in a full EIS.

Cape Wind took the EIS path through NEPA. The first EIS, prepared by the Corps, took roughly three years and was never used. The second EIS, prepared by DOI, took five years and is still bogged down in litigation.

It is too simplistic to conclude that Cape Wind would have enjoyed a similarly quick approval process had its lead agencies elected to prepare a mitigated FONSI rather than an EIS. The differences between the projects are, after all, great. Also, as the EA becomes the NEPA document of choice for many agencies, it may become as costly and burdensome as an EIS. But if there is a fast lane through NEPA, wouldn't it make sense to have renewable projects share that advantage?

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CARBON AND THE CONSTITUTION: BARRIERS TO LIFE-CYCLE ASSESSMENT THREATEN THE CREDIBILITY OF STATE BIOENERGY POLICIES

Jody Endres and Daniel Szewczyk

Justice O'Connor emphasized in her dissent in *Gonzales v. Raich* that "[one] of federalism's chief virtues . . . is that it promotes innovation by allowing for the possibility that 'a single courageous State may, if its citizens choose, serve as a laboratory; and try novel social and economic experiments without risks to the rest of the country.'" As with the medical marijuana use that was at issue in *Raich*, California leads the country in development of innovative strategies to combat climate change, including the nation's first low carbon fuel standard (LCFS) and cap-and-trade program. A recent federal court decision, however, has placed in doubt the constitutionality of life-cycle analysis (LCA)—a widely used measurement tool in greenhouse gas (GHG) regulation—when used by states to control emissions.

California's Use of LCA in Climate Change Regulation

The California LCFS requires suppliers and distributors to reduce the carbon intensity of transportation fuels sold in California by at least 10 percent by 2020 (Executive Order S-01-07; 17 Cal. Code Reg. § 95480). A fuel's carbon intensity score reflects its carbon dioxide equivalent (CO_2e) emissions "cradle to grave," spanning the entire process of producing and refining feedstocks, and distribution and end use by the consumer (*Id.* § 95481(a)(28)). This prevents shifting of carbon emissions among phases to avoid accountability. Although not required by statute, the California Air Resources Board (ARB) deploys LCA to arrive at default carbon intensity scores. Alternatively, regulated parties can customize their fuel "pathway" to lower its carbon intensity score.

Life-cycle carbon measurement necessarily includes CO_2e emissions from energy expended in fuel transport, as well as the energy efficiency of production processes. ARB thus assigns higher carbon intensity to otherwise chemically identical Midwestern corn ethanol because of the transportation distance to California and refiner's use of coal-based electricity. A regulated entity's total carbon intensity score will be higher if it includes Midwestern ethanol in its fuel portfolio. If a regulated party's overall portfolio score is higher than the state average, it must cancel out the deficit by retiring accumulated credits or purchasing credits from others (*Id.* § 95485). Where lower, it generates credits that can be sold or traded. Penalties apply under general air pollution control statutes for noncompliance (*Id.* § 95484(d)).

Litigation Challenging the Use of LCA as Unconstitutional

A coalition of farmer and ethanol advocacy groups, and petrochemical interests, challenged in federal court ARB's discriminatory LCA treatment of Midwestern ethanol and petroleum as an unconstitutional interference with interstate commerce and preempted by the federal renewable fuel standard (RFS) (*Rocky Mountain Farmers Union v. Goldstene*, 2011 WL 6934759 (E.D. Cal. Dec. 29, 2011)). California countered that its broad authority under the federal Clean Air Act and the Energy Independence and Security Act (EISA) to regulate fuels insulates the LCFS from application of the dormant Commerce Clause even if it interferes with interstate commerce. Rejecting the argument, the district court opined that Congress had not been "unmistakably clear" in the Clean Air Act that a state regulation like the LCFS be exempt from Commerce Clause scrutiny. The court then denied plaintiffs' summary judgment preemption claim without prejudice because neither party properly briefed the appropriate standard of review. The court did, however, base its preliminary injunction on both its conclusion that the LCFS violates the dormant Commerce Clause and "serious questions related to [Plaintiffs'] preemption claim."

Plaintiffs claimed that California's LCFS triggers the dormant Commerce Clause (DCC) because it facially favors in-state suppliers at the expense of out-of-state corn ethanol interests, and through application of its carbon scoring system that regulates conduct wholly outside of the state. The DCC invalidates state laws that impose commercial barriers or discriminate against articles in commerce by reason of their origin or destination out of state. The district court agreed that LCA from a methodological perspective may legitimately include an additional carbon value for transportation and choice of power source for refining to avoid leakage. It still concluded, despite California's argument that LCA applies equally to California-based fuels, that ARB's LCA application is undeniably discriminatory from a legal perspective. Where facially discriminatory, and motivated by simple economic protectionism, such discrimination is subject to a virtually per se rule of invalidity. The court pointed out that Midwestern corn ethanol was priced higher than California-made ethanol, thus disadvantaging the former economically.

California could only overcome the presumption of invalidity by showing that no other way exists to advance a legitimate state interest. California failed to convince the court that alternative means are not available to reduce GHG emissions even though the court acknowledged that states have a legitimate state interest in combating global warming. The court noted that California could implement a fossil fuel tax, require increased vehicle efficiency, or reduce the number of vehicle miles traveled. The court hinted in a footnote that a national standard would be useful to California in its efforts, highlighting the elephant in the room—Congress' failure to pass comprehensive climate change legislation that includes a low carbon fuel standard.

Plaintiffs also prevailed on their argument that default assumptions regarding Midwestern biorefineries' use of coal-fired electricity within LCA, however legitimate in the court's eyes, were "overtly favorable" to California producers and penalized out-of-state interests. California had countered that the assumption is not blanketly location based if a producer pursues a customized carbon intensity pathway versus accepting ARB's default values. Despite evidence that several Midwestern corn ethanol entities had successfully lowered their carbon intensity using this method, the court found that the customized pathway option increased costs for out-of-state interests relative to in-state ethanol production. The court further noted that ARB requires any customized pathway to achieve a greater than 5 gram carbon dioxide equivalent per megajoule CO_2e/MJ less than any default pathway, making it impossible to qualify as merely equivalent to California-based ethanol production. California was unpersuasive in its argument that some out-of-state sugar cane ethanol producers actually scored better in default carbon intensity values than in-state producers, thus evidencing a lack of discriminatory intent.

In addition to the application of strict scrutiny to facial discrimination, the court applied the same test to the LCFS carbon intensity values because of their effect of regulating extraterritorial conduct. The district court found that California's use of LCA that measures activities occurring outside the state, including the availability and choice of electricity sources and farming practices, violates the dormant Commerce Clause when those assumptions have the practical effect of controlling out-of-state conduct. California unsuccessfully argued that LCA's treatment of various production practices merely acted as an incentive to reduce emissions, not a mandatory regulation as the district court reasoned.

The Future of States' Climate Change Policies That Rely on LCA

California's appeal of the district court's decision is currently pending before the Ninth Circuit. The Ninth Circuit must first decide whether and how to address both the DCC claim and the preemption claim in light of the district court apparently basing its preliminary injunction on both premises but without analyzing at all why the LCFS is preempted by Clean Air Act section 211(o) (the renewable fuel standard). California emphasizes in its motion to stay the lower court's injunction that U.S. Supreme Court precedent does not invalidate a state regulation merely because it causes some businesses to shift from one interstate supplier to another. It emphasizes too, among other arguments, that if a regulated party is free to choose however and wherever to reduce GHG emissions, the LCFS cannot amount to an extraterritorial regulation.

On the issue of preemption, plaintiffs argued at the district court level that Congress balanced GHG reduction with the priority of achieving energy independence through support of the domestic corn ethanol industry. Thus, the LCFS unlawfully interferes with the RFS grandfathering of certain types of corn ethanol to meet its 20 percent GHG threshold. California now counters to the court of appeals that "serious preemption concerns" cannot support a preliminary injunction absent a finding that the balance of equities tips strongly against ethanol and oil's interests. The court of appeals must decide if the LCFS indeed acts as a substantial obstacle to Congress' goals so much that the entire regulation is constitutionally invalid.

The district court's DCC conclusions cast great doubt on the viability of LCA as an effective tool for state attempts to reduce GHG emissions and mitigate climate change. If upheld on appeal, states have no incentive to use LCA as a tool to decrease emissions; they can either exclude the offending factors from LCA, thereby decreasing its accuracy and severely limiting its effectiveness, or find another method of achieving GHG emission reductions.

Carbon accounting that may result in discrimination against out-of-state entities is not unique to the LCFS. Both California's Cap-and-Trade Program and renewable electricity standard require carbon accounting that prevents leakage of regulated emissions to jurisdictions outside of California that do not have similar requirements. Despite similar potential discrimination and conflicts with federal law, curiously neither statute has been challenged on constitutional grounds. LCA appears to have uniquely opened the door to legal challenges that lead ironically to more uncertainty, albeit of the legal versus scientific kind.

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TRIANGULATION: CALIFORNIA'S LOW CARBON FUEL STANDARD, CAP-AND-TRADE, AND THE COMMERCE CLAUSE

Keith M. Casto and Bradley M. Tanner

In 2006, California took a bold step when it passed the Global Warming Solutions Act of 2006 (AB 32) whose intent was to reduce the state's carbon footprint. Two of the major pillars of this landmark initiative are the low carbon fuel standard (LCFS) and the cap-and-trade program. One of the barriers to implementing effective programs to meet the lofty objectives of this initiative is the problem of leakage. Leakage does not reduce overall carbon output, but merely moves carbon-producing sources out of California where they face potentially less stringent regulation and take with them economic opportunities and jobs. California addressed this problem comprehensively in both programs.

A federal district court in California recently struck down certain LCFS provisions which addressed this issue as violating the Commerce Clause. In *Rocky Mountain Farmers Union, et al. v. Goldstene* (1:09-cv-02234, E.D. Cal., Dec. 29, 2011), the court took issue with how LCFS treated in-state ethanol versus out-of state ethanol. LCFS's primary mechanism and the central issue of the lawsuit was the use of the "carbon intensity" (CI) of fuels to estimate their estimated GHG emissions under a fuel life-cycle analysis. Among the many factors the CI addressed to arrive at the estimated GHG emissions from a particular source was the transportation factor, or the distance the ethanol travels from its production source to the California retailer, which in effect adversely impacts out-of-state ethanol's CI value. Thus, the court determined that it appeared on its face that California was treating in-state ethanol differently than out-of-state ethanol because out-of-state ethanol will always have to travel farther than in-state ethanol, and thus will always have a higher CI value. Once the court found facial discrimination, the state's position was considerably weakened because the court then utilized a strict scrutiny analysis (which placed the burden on the state to justify its analysis) instead of a rational basis balancing test approach that shifts the burden to the challenger. Had LCFS used a different approach or factors in its CI value that did not appear facially discriminatory, the court could have used the much less-stringent rational basis approach, which would have afforded the state some deference and probably would have allowed the court to find the LCFS provisions constitutionally sound.

The district court found that the LCFS was violative of the Commerce Clause because LCFS in essence imposes a surcharge on an out-of-state product made in an identical fashion irrespective of substantial policy reasons to do so. In-state corn ethanol from California and out-of-state corn ethanol from the Midwest are physically and chemically identical. The court dismissed the state's arguments that there was no discrimination because LCFS could, in some instances, also benefit out-of-state producers or burden in-state producers, or the fact that LCFS contained provisions that would allow a regulated party to amend its CI score by replacing the estimated GHG emissions derived from the CI factors with a facility's measured GHG emissions. The state did convince the court that LCFS served a legitimate local purpose under the *Massachusetts v. EPA* argument that states have a local and legitimate concern in reducing global warming, but failed to convince the court that no nondiscriminatory means existed which could accomplish the same effect. Under strict scrutiny, the court found LCFS violative of the dormant Commerce Clause because of its impermissible burden on interstate commerce, struck down the LCFS provisions, and preliminarily enjoined further implementation of LCFS.

The aftermath of the court's decision has left many to ponder whether similar constitutional arguments would invalidate analogous cap-and-trade provisions that apply to the electricity sector. California's cap-and-trade program, which goes into practical effect in 2013, will impose a GHG emissions cap and allocate the right for entities to emit GHGs through allowances and other compliance components. In its first phase, California's cap-and-trade program imposes an allowance requirement on imported electricity to disincentivize leakage. In particular, the program requires the "first deliverer" of electricity imported from out-of-state allowances to surrender allowances corresponding to the emissions associated with the generation of that electricity, much of which is coal-based and thus much dirtier, thereby requiring significantly more allowances. Therefore, some argue that California directly discriminates against out-of-state electricity providers and treats them differently than in-state electricity providers.

However, others argue that the fact that California will regulate only the first delivery importer of the electricity into the state means that it treats in-state and out-of-state electricity the same and does not discriminate. That first deliverer, a plant that is also located in California, is treated the same as an in-state electricity provider in terms of having to reduce its GHG emissions. Both operators of facilities in California as well as first deliverers of electricity to California have a compliance obligation for every metric ton of CO_2e for which a positive or qualified positive emissions date verification statement is issued. Thus, the electricity is treated the same and all entities have the same obligation as to reporting and compliance.

Another concern that opponents of cap-and-trade have voiced involves the fact that, like ethanol, electricity is the same end product regardless of whether it is produced from an out-of-state coal producer or through an in-state solar or wind producer; the same electricity is the result. Thus, these opponents argue that electricity under cap-and-trade is subject to the same pitfalls as ethanol under LCFS: since the end product is identical, the only difference is where and how electricity is derived, which again appears to burden interstate commerce. Proponents respond, however, that cap-and-trade does not in any way regulate electricity generation out of state, but only energy that is delivered into California. This may help explain why a similar challenge has not yet been asserted against this aspect of cap-and-trade.

Such an argument may still make cap-and-trade vulnerable to allegations that cap-and-trade has the "practical effect" of attempting to control conduct beyond the borders of the state, which would burden interstate commerce. Even assuming that was true, however, a court could most likely employ the rational basis test for facially neutral statutes instead of those that on their face appear to be discriminatory. This differing standard is what could save cap-and-trade from the same fate LCFS currently faces. Because cap-and-trade appears to be drafted in a manner which does not utilize factors such as the distance the product must travel, which would appear to always adversely affect out-of-state products, it could be considered to be facially neutral. This would pave the way for the court to utilize the less stringent balancing approach of the rational basis test and allow the court to find that cap-and-trade is a reasonable means to achieve legitimate state goals.

An additional reason why there have not yet been similar constitutional challenges to cap-and-trade is the unsettled landscape of this issue. The state has appealed the district court's decision. Irrespective of the outcome in the Ninth Circuit, it is likely the case would eventually end up in the hands of the U.S. Supreme Court, whose ultimate determination could decide the destiny of both LCFS and perhaps cap-and-trade.

Currently, the *Rocky Mountain Farmers Union* decision precludes California from taking into account the distance fuel travels to reach buyers in California as a determining factor. Practically, fuel from sources outside the state (i.e., the Midwest) has to travel farther than sources within the state's borders. To save the LCFS, California might either need to determine a CI score without taking transportation into consideration which could lessen the effect of a CI evaluation, or find a completely different method to rate different fuels. Beyond distance, the court also took issue with the fact that the CI evaluation differentiated between different farming methods that are used and even the different types of electricity used by the plant that produces the fuel. Based on this decision, if California continues to use any factor that appears to differentiate fuel from in-state producers with fuel from producers in other states or countries, there is a strong risk the dormant Commerce Clause claims will be sustained. Conversely, if California reverses course and modifies the LCFS so as to avoid treating fuel from out-of-state sources differently than fuel from in-state sources, either facially or by its practical effect, the state may thus moot these Commerce Clause claims and save the LCFS before the Ninth Circuit decides and the case reaches the U.S. Supreme Court.

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