All RECs Are Local: How In-State Generation Requirements Adversely Affect Development of a Robust REC Market

While most U.S. states have now adopted renewable energy portfolio standards, most also require a certain percentage of such generation to be “home grown.” These requirements lead to volatile and reduced-value markets for renewable energy credits and ultimately increase the cost of renewable energy. A review of the requirements suggests that either national or regional markets be fostered to reduce such adverse impacts of the requirements.

I. Introduction

The production of electrical energy from various renewable energy resources has long been promoted as an alternative to fossil fuel generation. Advocates over the years have highlighted, among other things, the environmental and national security (or energy independence) advantages of renewable energy. Since the enactment of the Public Utility Regulatory Policies Act of 1978, American regulators, policymakers, and other stakeholder groups have sought...
to incentivize the investment in, and development of, renewable energy generation, at the federal, state and local levels. Renewable energy production also enjoys broad popular support. A recent Pew Center poll found that 87 percent of the Americans polled would favor comprehensive energy legislation requiring utilities to produce more electricity from renewable sources.1

Since the late 1990s, states, in increasing numbers, have enacted renewable portfolio standard (RPS) regimes in order to support renewable energy investment, by requiring retail electricity suppliers to purchase a specified percentage of renewable energy to serve their customers over a specified period of time. Renewable energy certificates (RECs) were created to facilitate compliance with RPS regimes by allowing the environmental attributes of renewable generation to be bought and sold independently of the underlying energy. RECs have also been developed in part to catalyze renewable energy generation development by monetizing the environmental benefits inherent in such generation. RECs can provide renewable energy developers with an additional revenue stream and increase the financeability of renewable energy projects. In order to maximize the incentives RECs present to renewable energy developers, and therefore, increase the likelihood that more renewable generation will be built, there is a general consensus that the market for RECs should be robust and liquid.

Although a majority of U.S. states and the District of Columbia have enacted statutes which are intended to foster the development of compliance-based REC trading regimes, the United States currently does not have a single, unified REC market. Instead, varying state-specific regulations have largely fragmented the trading in RECs, creating differential REC values across various states and regions. Varying state-specific regulations have largely fragmented the trading in RECs, creating differential REC values across various states and regions. As long as REC trading is so fractured by state-specific regulations, volatility in the various REC markets will persist, which decreases their collective benefit to renewable energy developers and impedes the overall development of renewable energy generation in the United States.

In particular, regulations limiting the eligibility of renewable energy generation to produce RECs in a given state based on the geographic location of the underlying renewable energy (collectively referred to as “in-state generation requirements”) contribute heavily to the fragmentation of REC markets in the United States. Despite increasing use by many states of regional transmission organizations to monitor and validate RECs, geographical barriers to REC trading remain in various forms. While these types of regulations generally seek to maximize the local benefits of renewable energy development and promote in-state development, their effect is to hinder the development of any national or regional REC market and, thus, hinder U.S. renewable energy development as a whole.

Two recent developments may compel states to reconsider in-state generation requirements. First, the constitutionality of such requirements has been called into question. TransCanada Power Marketing Ltd. (“TransCanada Power Marketing”), a U.S. affiliate of Canadian energy developer TransCanada Corporation, recently mounted the first official challenge to the validity, under the Interstate Commerce Clause, of the in-state generation requirements included in Massachusetts’ solar REC trading scheme. Though TransCanada has since agreed to drop these claims in a partial settlement agreement with the state, this action could prompt challenges to similar limitations in other states. If any such challenge is successful, states may be required to eliminate (or limit) in-state generation requirements.
in their respective REC trading regimes.

Second, federal legislators continue to consider the enactment of a federal RPS or, alternatively, a clean energy standard (CES). Although Congress failed to pass an RPS in 2009 and 2010, certain lawmakers likely will continue to try to enact some form of federal renewable energy purchasing mandate. For instance, President Obama and several key lawmakers, in an effort to appeal to a broader range of interests, have recently focused on the passage of a federal CES in lieu of an RPS. A federal CES appears more probable than a federal RPS in the current political and economic climate, but it remains speculative whether a federal CES will be adopted, and even if it were to pass, what such a federal CES would entail.

This article begins with a general description of RPS regimes and RECs, before describing the in-state generation requirements of a representative selection of RPS regimes. Next, this article illustrates the collective disincetivizing effect on renewable energy development of individual states’ in-state generation requirements. This article then concludes by examining how two developments may, or could, affect states’ ability to enact or enforce in-state generation requirements in the future—constitutional challenges to such requirements and the enactment of a federal RPS or CES.

II. Renewable Portfolio Standards and the Promise of a Renewable Energy Certificate Market

A renewable portfolio standard is a regulatory mechanism employed to promote the production of electricity from renewable energy resources. Massachusetts and Connecticut were among the first states to enact mandatory renewable portfolio standard requirements. Since that time, about 30 U.S. states and the District of Columbia have enacted mandatory RPS requirements. An RPS typically requires utilities that serve retail customers (also known as “load-serving entities”) to demonstrate that a certain percentage or volume of the power that they supply to retail customers stems from renewable energy. Under many RPS regimes, a load-serving entity may satisfy its RPS obligations by purchasing renewable energy certificates from eligible renewable energy resources. A REC is a tradable instrument that represents the beneficial environmental attributes of renewable energy generation. When RECs are unbundled from the underlying energy being produced, RECs provide a separate product, which can be sold or traded separately from the energy. RECs thus provide an additional stream of income for renewable energy developers and promote the efficient allocation of renewable energy investment.

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This potential additional income stream helps to attract additional investment in renewable energy generation. Generally speaking, the development of renewable energy facilities, like conventional energy facilities, requires large up-front capital expenditures. Many renewable energy facilities obtain debt and/or equity financing for such expenditures on a nonrecourse, project finance basis. Under a project-based financing structure, facility assets and any revenue-producing project products or revenue-producing contracts serve as collateral for the debt, and debt obligations are repaid from the cash flow produced by such project contracts. Under this type of financing structure, potential debt or equity investors “base credit appraisals on the projected revenues from the operation of the facility, rather than the general assets or the credit of the promoter of the facility.” In theory, renewable energy developers should be able to obtain more favorable credit appraisals and credit terms if they
are able to generate and sell both renewable energy and RECs separately, than they would if they were only able to sell RECs bundled with the renewable energy produced.10

III. The Reality of Renewable Energy Certificate Trading: Fractured, Volatile Markets

RECs have the potential to create additional value in the development and financing of renewable energy projects, but because of regulatory issues, this potential has not yet been fully realized. As Norbert Wohlgemuth and Reinhard Madlener point out, the importance of the effect of RECs on renewable energy development “depends on the market price of the certificates and as such on supply and demand characteristics.”11 The United States currently does not have a single, unified REC market and its regional markets are still developing; instead, varying state-specific regulations have created a large number of disparate REC trading regimes, with less supply and demand than would be available in a more harmonized national market or series of regional markets.

One component of current state-based RPS regulations which has had perhaps the most deleterious effect on the market’s ability to realize the full potential of RECs is the in-state generation requirement. In-state generation requirements in part stem from states’ self-interest in promoting renewable energy within their own borders, as certain Montana legislative findings illustrate well: “renewable energy production promotes sustainable rural economic development by creating new jobs and stimulating business and economic activity in local communities across Montana,” “increased use of renewable energy will enhance Montana’s energy self-sufficiency and independence,” and “all consumers and utilities should support expanded development of these resources to meet the state’s electricity demand and stabilize electricity prices.”12 These rationales succinctly describe many of the primary justifications for the general promotion of renewable energy. Indeed, as the Montana legislature has found, “fuel diversity, economic, and environmental benefits from renewable energy production accrue to the public at large.”13 Although the public benefits of renewable energy are not hindered by governmental boundaries, many states promote renewable energy generation and its attendant public benefits within their own borders. In-state generation requirements appear in a wide variety of forms across the states. A brief survey of the regulatory regimes governing renewable energy certificate markets in several states highlights this point.

A. Texas

In Texas, retail electric providers, municipally-owned utilities, and electric cooperatives may satisfy the minimum renewable energy requirements applicable to such entities by purchasing RECs from eligible renewable energy resources.14 Texas regulations define a “renewable energy credit” in relevant part as one MWh of renewable energy “that is physically metered and verified in Texas.”15 The Electric Reliability Council of Texas (ERCOT), which administers the REC trading regime and tracks the production and transfer of RECs in Texas,16 has further defined this requirement to allow out-of-state renewable energy resources to produce RECs eligible to be sold in the Texas market only if the underlying energy satisfies certain deliverability requirements within Texas. That is, an out-of-state REC is only eligible to be sold in the Texas market if (1) the...
first metering location for the underlying generation is located within Texas, (2) the renewable energy resource utilizes a dedicated transmission line into Texas (i.e., all generation metered at the injection location must come from the same facility), and (3) the renewable energy resource obtains certification from the Public Utility Commission of Texas. As of the end of 2009, there was no out-of-state participation in the Texas REC trading program.

B. Ohio

In Ohio, all electric utilities and all electric service companies serving retail customers may satisfy the minimum renewable energy requirements applicable to such entities by purchasing RECs from eligible renewable energy resources. Ohio statute dictates that at least half of the total renewable energy (including any unbundled RECs purchased in lieu of purchasing renewable energy bundled with its environmental benefits) utilized by a regulated entity to fulfill such requirements must be produced by renewable energy resources located in Ohio. Any remainder must come from renewable energy resources that “can be shown to be deliverable into” the state. Ohio regulations further define the deliverability requirement to require that renewable energy originate from a renewable energy resource within a state that is “contiguous to Ohio” or other locations, so long as it can be demonstrated that “the electricity could be physically delivered to the state.”

Ohio law provides that regulated entities may request from the Ohio Public Utilities Commission (Ohio PUC) a “force majeure” determination excusing all or a portion of such entity’s minimum renewable energy requirements for a given compliance year. The Ohio PUC is required to consider the availability of renewable energy resources and RECs in the State of Ohio as well as in other jurisdictions within the Mid-Atlantic and Midwest regional transmission organizations (PJM Interconnection, LLC (PJM) and Midwest Independent Transmission System Operator, Inc. (MISO), respectively), which may not be contiguous to Ohio and/or may not be physically delivered or even deliverable to the state. It is unclear, however, whether the regulations require (or even allow) the Ohio PUC to require regulated entities to purchase renewable energy or RECs from generation resources that cannot be physically delivered to the state.

C. North Carolina

In North Carolina, electric public utilities, electric membership corporations and municipalities may satisfy the minimum renewable energy requirements applicable to such entities by purchasing RECs, up to 25 percent of which may be derived from out-of-state renewable energy facilities. While out-of-state renewable electric power purchased by electric public utilities in order to meet such requirements must be delivered to a “public utility that provides electric power to retail electric customers in the state,” there is no such deliverability requirement with respect to RECs.

D. Pennsylvania

In Pennsylvania, electric distribution companies and electric generation suppliers may satisfy the minimum renewable energy requirements applicable to such entities by purchasing alternative energy credits from alternative energy sources within the Commonwealth of Pennsylvania or within the transmission systems operated by the regional transmission organizations MISO (with respect to all electric distribution companies and electric generation suppliers located within such state).
entities by purchasing renewable energy certificates issued by the New England Power Pool Generation Information System (NEPOOL GIS), so long as (1) such certificates are for energy produced using a renewable energy technology that is eligible under Connecticut law and (2) the underlying energy was (i) produced by a generating unit located within the jurisdiction of the transmission system operated by the regional transmission organization ISO New England Inc. (ISO-NE) or (ii) was imported into the balancing authority area of ISO-NE pursuant to and in accordance with NEPOOL GIS’s import rules. The Connecticut Department of Public Utility Control has clarified that the RECs eligible to satisfy renewable energy obligations in Connecticut potentially could come from Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and parts of Maine, as well as New York, Pennsylvania, New Jersey, Maryland, or Delaware, “if these states’ Renewable Portfolio Standards meet certain comparability standards.”

F. New Jersey

In New Jersey, which has one of the most aggressive RPS regimes in the U.S., supplier/providers generally may satisfy the minimum renewable energy requirements applicable to such entities by purchasing RECs issued by the PJM Generation Attribute Tracking System (GATS). “Class I” and “Class II” RECs must be generated within the PJM region or delivered into the PJM region through “dynamic scheduling.” Thus, Class I and Class II RECs may be generated in a relatively large number of states. On the other hand, New Jersey has a distinct solar energy requirement, and the generation underlying solar RECs used to comply with this requirement may only occur within the state. On Feb. 10, 2011, the New Jersey Board of Public Utilities also revised the state’s RPS to include an obligation to purchase a minimum percentage of offshore wind energy (or “ORECs”), which will be a component of the Class I renewable energy requirement. To qualify to produce ORECs, an offshore wind facility must be interconnected to New Jersey’s electrical transmission system.

G. Massachusetts

In Massachusetts, retail electricity suppliers, generally
speaking, may satisfy the minimum renewable energy requirements applicable to such entities by purchasing RECs issued by the NEPOOL GIS. Thus, as in Connecticut, the RECs eligible to satisfy most renewable energy obligations in Massachusetts could potentially come from a large number of states, and RECs eligible in Massachusetts may even come from Canada. In fact, the Massachusetts Department of Energy Resources (DOER) recently stated that the supply of RECs produced in jurisdictions outside the ISO-NE balancing authority area increased by nearly 60 percent from 2007 to 2008, “after more than doubling between 2006 and 2007.” For the year 2008, fully 80 percent of the renewable energy used to comply with the Massachusetts renewable energy obligations (whether as energy or RECs) was generated outside the Commonwealth of Massachusetts. New York renewable energy resources (including wind farms and landfill methane plants) “were the single largest source... at 27 percent of the total, closed followed by 26 percent from Maine (mostly biomass), 14 percent from New Hampshire (mostly biomass), [and] 13 percent from wind farms in adjacent Canadian provinces.”

As is the case with other RECs in Massachusetts (which are not tied to in-state generation), solar RECs will be issued and tracked using NEPOOL-GIS. Despite a challenge (described below) to the Solar Carve Out Program on the grounds that, inter alia, its in-state generation requirements violated the Interstate Commerce Clause of the U.S. Constitution, final Solar Carve Out Program regulations, which retain the in-state generation requirements, were promulgated in December 2010.

H. California

Perhaps nowhere else in the country are in-state generation requirements the subject of as much uncertainty and debate as in California. The following sections summarize the rapidly evolving California RPS program.

1. California Renewables Portfolio Standard. The California RPS, enacted in 2002, requires retail sellers of electricity to procure at least 20 percent of their electricity from renewable energy sources by Dec. 31, 2010. The California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) jointly implement the RPS program. The CEC is responsible for certifying renewable facilities and the CPUC is responsible for ensuring compliance with the RPS requirements. To facilitate compliance, the CPUC and CEC established a REC-based accounting system. Electricity generated from a facility cannot count towards meeting RPS compliance obligations until the CEC certifies the facility as RPS-eligible. The CEC has certain additional requirements for out-of-state
facilities beyond those required for in-state facilities:\footnote{51}
- Must be connected to the Western Electricity Coordinating Council (WECC) transmission system;
- Generally must have begun operating after Jan. 1, 2005;
- Cannot cause or contribute to any violation of a California environmental quality standard or other applicable requirements within California; and,
- If located outside the United States, must be developed and operated in a manner that is as protective of the environment as would a similar facility be if it were located in California.

Out-of-state facilities must also satisfy electricity delivery requirements under the RPS.\footnote{52} Electricity is considered delivered when it is either generated at a California facility or is “scheduled for consumption by California end-use retail customers” pursuant to Cal. Pub. Res. Code § 25741(a).\footnote{53} Electricity that is scheduled for consumption by a California end-use retail customer may be “generated at a different time from consumption by a California end-use customer” by allowing “firming” and “shaping” of electricity. Firming and shaping “refers to the process by which resources with variable delivery schedules may be backed up or supplemented with delivery from another source to meet customer load.”\footnote{54} A facility located outside of California but with a first point of interconnection to the WECC inside of California need not comply with further delivery requirements.\footnote{55}

The CEC guidelines provide that “to count generation from out-of-state facilities for RPS compliance,” the RPS-certified facility must enter into a power purchase agreement (PPA) with a retail seller, procurement entity, or third party.\footnote{56} Under the terms of the PPA, the retail seller or procurement entity will then secure transmission into California, either by facilitating transmission directly to California, or by entering into another agreement with a facility in the WECC transmission system to deliver the electricity to California.\footnote{57} The CEC then compares the amount of RPS-eligible electricity generated by the facility with the amount actually delivered into California, and the amount actually delivered to California earns RECs.\footnote{58}

The CPUC has imposed an additional layer of restrictions on California utilities’ ability to rely on out-of-state facilities for RPS compliance. Either bundled RECs or unbundled RECs (generally called tradable RECs (TRECs)) can be used towards RPS compliance obligations after the CPUC issued a decision on Jan. 14, 2011, creating a TREC trading regime.\footnote{59} The CPUC decision, however, imposes significant limitations on the use of TRECs. In particular, the CPUC has defined most out-of-state procurement of RECs as unbundled TRECs, and only allows the three largest investor-owned utilities (IOUs) to obtain 25 percent of their RECs through TRECs.\footnote{60} The remaining 75 percent must be obtained through bundled REC transactions, which include transactions where the generator’s first point of interconnection is with a California balancing authority (such as the CAISO), or the RPS-eligible energy is dynamically transferred to a California balancing authority area. Unlike states such as Texas, the CPUC has not yet determined whether out-of-state renewable transactions that are delivered into California through dedicated transmission arrangements should be classified as bundled RECs, and therefore not subject to the 25 percent cap. The CPUC decision extends the period of time in which these limitations will remain in effect to December 2013.\footnote{61} Requests for rehearing of Jan. 14, 2011, decision have been filed, and subsequent judicial challenges may also occur. As a result, policies concerning TRECs

are likely to continue to shift and evolve.

2. California Renewable Electricity Standard. On Sept. 15, 2009, California Gov. Arnold Schwarzenegger issued an executive order requiring the California Air Resources Board (CARB) to adopt regulations, pursuant to the California Global Warming Solutions Act of 2006 (AB 32), that would require California utilities to meet a 33 percent renewable energy target by 2020. The executive order was issued after Gov. Schwarzenegger vetoed two bills that would have increased the RPS to 33 percent, as Gov. Schwarzenegger expressed concern that the legislation too greatly restricted the use of out-of-state renewable resources to meet that requirement. The CARB regulations are intended to increase the use of renewable energy while facilitating the use of out-of-state energy to meet this goal.

On Sept. 23, 2010, CARB unanimously adopted the Renewable Energy Standard (RES) to require a 33 percent by 2020 renewable energy procurement mandate for most retail sellers of electricity in California, including but not limited to publicly-owned utilities (POUs) and the state’s three largest IOUs, Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E). Similar to the RPS, the RES uses an REC-based accounting system to ensure that regulated entities are in compliance with the required percentage of renewable energy. However, the RES differs from the RPS because it likely will increase the availability of out-of-state renewable resources for RES compliance. In particular, the RES would:

- Eliminate the delivery requirement, which would permit more out-of-state facilities to provide electricity to California under the RES than the RPS;
- Allow for an unlimited use of unbundled or TREC; and
- Create a more flexible certification process, and
- Allow the banking and trading of RECs.

While the RES is more flexible than the RPS, there remain obstacles to compliance for out-of-state facilities. Under the RES, out-of-state facilities must continue to meet certification requirements that are not required of other facilities, including that a facility must not contribute to a violation of California environmental quality standards. Facilities located outside the United States must also be developed and operated in a manner that is protective of the environment similar to if it were located in California.


Senate Bill SBX1 2 expands the RPS to cover publicly owned utilities. Senate Bill 2X1 2 sets new limits on the use of out-of-state renewable resources. After an initial phase in period, Senate Bill 2X1 2 limits the use of out-of-state renewable resources to 25 percent of a utility’s RPS obligations, subject to limited exceptions for out-of-state facilities located near California. Senate Bill 2X1 2 establishes maximum limits for using TREC: up to 25 percent of RPS requirements until Dec. 31, 2013; up to 15 percent during the Dec. 31, 2014, to Dec. 31, 2016, compliance period; and up to 10 percent thereafter. Therefore, after Dec. 31, 2016, only 10 percent of a utility’s RPS obligations can be satisfied with TREC. Firmed and shaped electricity can be used to satisfy the portion of a utility’s compliance obligation that is not required to be satisfied by minimum in-state resources but cannot be satisfied with TREC.
The CPUC may waive or delay certain compliance obligations if a utility can demonstrate that it has taken all reasonable steps to comply and certain enumerated constraints exist that prevent its timely compliance.\textsuperscript{75}

IV. Effects of REC Market Fragmentation

In-state generation requirements, in addition to other variations among state RPS requirements,\textsuperscript{76} contribute to significant volatility in REC prices in individual markets and significant variability in REC prices among the different REC markets. For example, prices for Texas RECs, which experienced a critical price drop from 2005 to 2006 (from $10–15 per REC in January 2005 to approximately $5 per REC by July 2006),\textsuperscript{77} now seem to be relatively stable but have become among the lowest-priced RECs available in any U.S. market. Texas prices throughout 2010 held steady at approximately $1 per REC.\textsuperscript{78}

Compare these prices to average Class I REC prices in Connecticut, which have been among the highest across state REC trading programs. Class I REC prices in Connecticut have varied from a low of less than $5 per REC around the end of 2005 to a high of around $50 per REC throughout the latter half of 2007.\textsuperscript{79} Throughout 2010, Class I REC prices in Connecticut ranged from a high of approximately $30.50 per REC to a low of approximately $11 per REC.\textsuperscript{80} In Pennsylvania, “there were more Tier II credits created in each of the years from 2005 through 2008 than will be needed in 2021. As a result, there will likely be many more Tier II credits created in any given year than are needed to meet annual requirements during the 2010–2021 period.”\textsuperscript{81} Such excess credits may be eligible for use in another state, depending on applicable eligibility requirements, and Pennsylvania RECs are valid for two compliance years after the compliance year in which they were created. However, excess Tier II credits may also cause price fluctuations or depress prices for such credits.

In REC markets with relatively restrictive in-state generation requirements, REC prices can become very sensitive to the timing and size of even individual projects, which renders rational economic planning infeasible with respect to RECs. Ohio’s recent REC experience illustrates this point. As discussed above, Ohio requires that at least half of the renewable energy or RECs used to comply with Ohio’s renewable energy requirements be generated within the state and allows the remainder to be generated in contiguous states (absent a force majeure determination as described above). Ohio-generated REC prices increased steadily within 2009, from approximately $9 per REC to approximately $35 per REC.\textsuperscript{82} Ohio REC prices as of mid-2010 remained within the high end of this range. Jack Velasquez, vice president for environmental products at Spectron Energy, has stated, “It’s safe to say the Ohio REC prices are the highest in the country.”\textsuperscript{83} Velasquez attributes these high prices to lack of supply. Indeed, according to a recent Platts article, “Ohio lacks the wind energy capacity, with only about 4 MW of installed capacity as of June 2010.”\textsuperscript{84} In August 2010, however, the Ohio Public Utilities Commission approved a plan to retrofit an Ohio coal energy facility to enable it to burn wood pellets and allowed the facility to generate extra RECs, pursuant to a biomass-focused incentive included in the Ohio RPS.\textsuperscript{85} Platt’s has predicted that in-state Ohio REC prices could fall to as low as $1 per REC once this facility commences commercial operation.\textsuperscript{86} If Ohio’s RPS did not include restrictive in-state generation requirements, in-state REC prices may not have increased to the levels they did in 2009, but they also would not be likely to fall from $35 per REC to $1 per REC and be nearly as volatile. While higher REC prices
are attractive to developers in the short term, volatility in the market is likely to undermine the value of those prices to investors and lenders in the long term.

Bloomberg New Energy Finance recently conducted a REC markets survey, in which respondents were asked to anticipate REC prices in various REC markets for the 2013–2020 time period, which highlights REC price uncertainty in U.S. markets. With respect to the PJM REC market, for example, respondents generally expected future REC prices to be high, but specific expectations regarding REC prices varied considerably. Twenty-three percent of respondents felt REC prices for this time period would be in the $0–5 per REC range, while 39 percent of respondents believed REC prices for the same time period would be over $40 per REC.87 As Christopher Berendt has noted, “It is difficult for renewable energy investors to ascertain what they will get from the sale of the RECs their projects generate next year, let alone in five or 10 years.”88

Many U.S. renewable energy facilities are developed and constructed using a limited-recourse project finance structure. Under such a structure, the borrower typically is a special-purpose entity created by the project sponsor and the collateral typically consists of, *inter alia*, a pledge of the membership or other ownership interests of the borrower and the facility’s current and future assets and assignments of the facility’s various contractual rights. Facility revenue is the most typical method of repayment in such project financings. The borrower’s ability to repay a project finance loan, as described above, then depends largely on the amount of, and certainty with respect to, the facility’s projected revenues. Financing parties thus consider these factors when making initial credit approvals, sizing project finance loans and negotiating terms and conditions of credit agreements. When financing parties perform due diligence reviews of a potential borrower’s project, then, the facilities’ offtake agreements play a central role. Because REC prices historically have been so varied (across states and regions) and volatile (within states and regions), financing parties tend to prefer that renewable energy developers enter into long-term REC offtake agreements. However, given the volatility of such markets, as well as the uncertainty with respect to federal action, long-term REC purchase and sale agreements at sustainable prices are not always available in every market.

As an initial matter, if a borrower is unwilling or unable to fully contract its projected REC supply over the term of the loan, financing parties may elect to discount, or even eliminate, projected REC revenues from the financial models such financing parties use to size loans (thus making less debt financing available to the borrower), or they may attach additional conditions a borrower must satisfy prior to accessing debt that is based on projected REC revenues. REC offtake agreements preferred by financing parties can have terms of as long as 20 years or more. In order to enter into such long-term agreements, renewable energy developers often must enter into bundled agreements to sell RECs and other products, such as capacity, energy, or ancillary services, to offtakers. The potential pool of offtakers interested in entering into such long-term agreements tends to be limited to public utilities, to the exclusion of energy and/or REC marketers, which sell these products in the spot market. Renewable energy developers often must shoulder much of the pricing risk with respect to RECs in such long-term contracts. Change of law risk is also heavily negotiated between developers and offtakers and REC agreements may include “regulatory out” clauses that provide for contract abrogation or
termination due to regulatory changes that negatively affect the applicable REC market(s).

Because they are not able to capture the full potential value of RECs in long-term contracts, renewable energy developers may not be able to realize the full potential benefits of RECs when project financing their facilities. The amount of debt financing available to such developers may still be lower than the amount that theoretically could be obtained if a thriving, stable REC market allowed for consistent long-term REC price projections. Interest rates and other terms and conditions also may be less favorable than otherwise would be obtainable, and financing institutions may require additional sponsor support or other assurances. The effects of REC market fragmentation indeed touch all aspects of the development and construction of renewable energy facilities in the United States.

V. Recent Developments Potentially Threaten In-State Generation Requirements

Two recent developments may force significant changes with respect to in-state generation requirements in state RPS programs. First, the constitutionality of in-state generation requirements in REC trading regimes recently was called formally into question. On April 16, 2010, TransCanada Power Marketing Ltd. (“TransCanada”), a U.S. affiliate of Canadian energy developer TransCanada Corporation, challenged the validity, under the Interstate Commerce Clause, of the in-state generation requirements included in Massachusetts’ Solar Carve Out Program (described above).

Article I of the U.S. Constitution vests in Congress the authority to “regulate Commerce...among the several States.” This grant of exclusive federal power carries an implicit consequence for states’ powers. When states regulate commerce within their own borders, they cannot enact laws that discriminate against out-of-state economic interests in favor of in-state competitors absent congressional authorization or some other source of constitutional authority.” In its recent complaint, TransCanada argued that the in-state generation requirements under the Solar Carve Out Program are facially invalid under the Interstate Commerce Clause, arguing that such requirements represent “differential treatment of in-state and out-of-state economic interests that benefits the former and burdens the latter.” It sought (1) a judgment from the United States District Court for the District of Massachusetts, Central Division, declaring that the Solar Carve Out Program was “unconstitutional, invalid and unenforceable” to the extent that it requires retail electricity suppliers to purchase Solar RECs “from generation units located in Massachusetts to the exclusion of generation units located outside Massachusetts” and (2) temporary and permanent injunctions against enforcement of the Solar Carve Out Program.

On May 28, 2010, the parties entered into a partial settlement agreement which required the State of Massachusetts to amend certain regulations governing the Solar Carve Out Program but allowed the State to retain the in-state generation requirements.

While the partial settlement agreement resolved the immediate uncertainty that plagued Massachusetts’ Solar Carve Out Program during pendency of the challenge, the constitutionality of in-state generation requirements remains unresolved. This action could prompt challenges to such requirements in other states. If any such challenge is successful, states may be required to eliminate or significantly modify...
in-state generation requirements in their respective REC trading regimes.

Second, federal legislators continue to consider the enactment of a federal RPS or CES. Congress failed to pass an RPS in 2009 or 2010 despite a concerted effort by the Democratic leadership. The results of the November 2010 elections make it unlikely that a political consensus will form around RPS legislation in the near term. President Obama and several key lawmakers, in an effort to appeal to a broader range of interests, have recently focused on the passage of a federal CES. Although not strictly defined, a CES would likely require utilities to procure a certain percentage of energy from renewable sources similar to an RPS but would also allow other energy sources with cleaner greenhouse gas profiles than traditional coal-based generation, such as nuclear, clean-coal, and possibly natural gas, to count towards compliance obligations. A CES appears more probable than an RES with the current Congress but it remains speculative whether a CES will be adopted, and if it were to pass, what such a CES would entail. In particular, it is difficult to predict whether and to what extent a federal CES may preempt more aggressive state RPS programs or how the two types of programs may coexist.

Even to the extent a federal RPS or CES program passes Congress, it remains unclear whether the program would fully eliminate in-state generation requirements, though doing so would be critical to the success of any federal, or even regional, REC trading regime. For example, Sen. Jeff Bingaman introduced the American Clean Energy Leadership Act of 2009 to the Senate, which was considered front-runner RPS legislation. Although the Bingaman legislation did not pass, it is informative of proposed RPS legislation and a CES would likely contain some similar attributes. The Bingaman legislation would amend Title VI of the Public Utility Regulatory Policies Act of 1978 and would require electric utilities to obtain 15 percent of their “base quantity” of electricity from renewable resources by 2021. Utilities would comply with this requirement through the use of RECs, federal energy efficiency credits, or alternative compliance payments at the rate of 2.1 cents per kilowatt hour, adjusted for inflation. The legislation would direct the Secretary to create a tradable REC program, but does not detail specifics of how a REC market would function.

The Bingaman legislation did not, however, solve the problem of geographic discrimination that exists under the state RPS programs. In particular, the Bingaman legislation specifically stated that “nothing in this section diminishes any authority of a State or a political subdivision of a State to adopt or enforce any law or regulation respecting renewable energy or energy efficiency, or the regulation of electric utilities,” and provided further that there would be “coordination between the Federal program and state programs.” Indeed, a utility would be in compliance if it was subject to a state RPS program and complied “with the state standard by generating or purchasing renewable electric energy or renewable energy certificates or credits representing renewable electric energy.” Thus, Bingaman’s legislation would not preempt state legislation, and it would be possible to comply with the federal standard simply by complying with state programs.

VI. Conclusion

RECs have been created by states, in part, to allow developers of renewable energy facilities to realize monetarily the environmental benefits inherent in renewable energy generation. Many states have understandably chosen to impose in-state
generation requirements on RECs used to qualify with such states’ RPS regimes, in an effort to promote the myriad benefits of renewable energy development within state lines. By geographically limiting qualifying RECs in this way, however, states that have adopted in-state generation requirements have (perhaps unintentionally) created small, disparate markets in RECs and have also impacted the ability of renewable energy projects to obtain price transparency in regional markets, all of which ultimately increases the net cost to produce (and ultimately the cost to utility ratepayers) of renewable energy. Such price volatility and variability will ultimately reduce the amount and efficiency of renewable energy projects and transactions in any given state market. Renewable energy developers typically are forced to shoulder these price volatility risks, which diminishing the catalyzing effect RECs were intended to create. At the margin, REC price variability and lack of liquidity may negatively impact renewable energy developers’ appetites for renewable energy development in certain states or regions, regardless of renewable resource availability in such areas.

Federal legislators continue to consider the enactment of a federal renewable portfolio standard or, alternatively, a clean energy standard.
Some in-state generation requirements may also be judicially vulnerable, as the TransCanada litigation attempted to accomplish, under the Interstate Commerce Clause of the U.S. Constitution. But even a judicial ruling that limits or prevents imposing in-state generation requirements would not necessarily solve the problem, without any regional or national market for RECs. As part of its ongoing evaluation of national energy and environmental policy, we suggest that Congress legislatively eliminate or limit in-state generation requirements at the federal level, by adopting either a federal RPS, that preempts state RPS in-state generation requirements, either in whole or, at a minimum, with respect to the minimum renewable energy purchase obligation set forth in the federal RPS, or a federal CES that does not discriminate or allow discrimination against out-of-state renewable resources. At a minimum, Congress should consider incentives to foster regional REC markets that are coincident with regional transmission organizations, if not a fully national market. Even in the absence of federal action, states can – and some states currently are – developing unified regional REC markets, with standardized rules for trading within, and in limited cases among, such markets. However, unless in-state requirements are eliminated or limited, such regional markets will still suffer from price volatility and lack of liquidity. Federal action should help to consolidate the market for RECs in the United States, stabilize REC prices and encourage the growth of long-term, unbundled REC purchase and sale agreements.99

Endnotes:


2. Other names for an RPS include renewable energy standard, renewable electricity standard, and environmental portfolio standard.


6. A single REC typically represents the environmental attributes of 1 MWh of renewable energy.


10. See, e.g., Norbert Wohlgemuth and Reinhard Madlener, Financial Support of Renewable Energy Systems: Investment vs. Operating Cost Subsidies, Proceedings of Norwegian Association for Energy Economics Conference, “Towards an Integrated European Energy Market,” Bergen, Norway, Aug. 31–Sept. 2, 2000 (“With such a system, renewable electricity is fed into the electricity grid and sold at market prices, but the renewable electricity producer also receives a certificate that is sold on the market for certificates and improves the competitiveness of the renewable production, because it has the effect of a subsidy.”)

11. Id.


13. Id. at § 69-3-2002(4) (emphasis added).


16. See Tex. Admin. Code § 25.173(g); see also Electricity Reliability Council of Texas, Inc., State of Texas
unique challenges in Texas. See interstate REC trading may pose ERCOT region. For these reasons, only limited jurisdiction over the ERCOT region and the Federal limited interstate interconnections in Note that Texas currently has only press_releases/2010/nr-05-14-10. www.ercot.com/news/Contemporary Appraisal Jurisdictional Status: A Legal History and Jared M. Fleisher, generally energy resources, whether located within or outside of the state. See Tex. ADMIN. CODE § 25.173(o).


19. OHIO REV. CODE ANN. §§ 4928.64(B)(2), 4928.65 (year). Renewable energy credits traded in Ohio are tracked using the PJM-GATS and M-RETS tracking systems. OHIO ADMIN. CODE § 4901:1-40-04(D)(2).

20. OHIO REV. CODE ANN. §§ 4928.64(B)(3).

21. OHIO ADMIN. CODE § 4901:1-40-01(I) (year). Note that the regulations are ambiguous as to whether the underlying energy must be delivered into the state in order for such energy to produce renewable energy credits eligible to be traded in Ohio.

22. OHIO REV. CODE ANN. § 4928.64(C)(4).

23. Id.

24. N.C. GEN. STAT. §§ 62-133.8(b)(2)(e); 62-133.8(c)(2)(d) (year). Note that the 25 percent limitation does not apply to electric public utilities with fewer than 150,000 retail jurisdictional customers in North Carolina as of Dec. 31, 2006. Id. As of July 1, 2010, North Carolina Renewable Energy Tracking System (NC-RETS), which was developed and will be implemented by Automated Power Exchange, Inc. (APX), has been responsible for issuing and tracking RECs sold in the North Carolina market. See North Carolina Renewable Energy Tracking System (NC-RETS), at http://www.ncrets.org/; see also, APX, Inc., Solutions & Services for the Energy & Environmental Markets, http://www.apx.com/. Note that APX, Inc. also developed and currently administers the Michigan Renewable Energy Certification System (MIRECS), M-RETS, NEPOOL GIS, PJM GATS, and WREGIS, and developed and initiated the Texas REC program.

25. Id. at § 62-133.8(b)(2). Note that electric membership corporations and municipalities may not purchase out-of-state renewable energy to meet the minimum renewable energy requirements. See id. at § 62-133.8(c)(2).

26. Id. at § 62-133.8(b)(2);

27. Though precise definitions vary among jurisdictions, an “alternative energy credit” is defined substantially similarly to a “renewable energy credit” or “renewable energy certificate.”

28. PA. STAT. ANN. §§ 1648.3(e); 1648.4 (year); Pennsylvania Public Utility Commission, Final Rulemaking Order, Docket No. L-00060180 (May 28, 2009), at 11.


30. Id.


32. CONN. GEN. STAT. § 16-245a(b).


34. New Jersey has enacted distinct RPS requirements with respect to Class I renewable energy and Class II renewable energy, each of which is defined to include different renewable energy resources. For example, Class I renewable energy includes, among other resources, wind, solar, geothermal and wave or tidal energy. Class II renewable energy includes certain hydropower and resource recovery facilities. Class I RECs may be used to satisfy Class II renewable energy requirements, but the reverse is not permissible. See 8 N.J.A.C. § 14.8-2.3(f).

35. 8 N.J.A.C. § 14.8-2.7.

36. 8 N.J.A.C. § 14.8-2.9(d).


38. MASS. GEN. LAWS ANN. 25A §11F (2009); 225 MASS. CODE REGS. §§ 14.05(1)(c)-(d); 14.05(5).


40. Id. at 3.

41. Id.

42. Id.

43. 2008 Mass. Acts Ch. 169, Sec. 11F(g) (emphasis added). The production capacity limit in this requirement was subsequently increased to 6 MW. See 225 Mass. Code Regs. § 14.05(4)(a).


46. See S.B. 1078, Gen. Assem. 2002, Reg. Sess. (Cal. 2002); Cal. Pub. Util. Code § 399.15(b)(1); see also Cal. Pub. Util. Code § 399.12(g) (“‘Retail seller’ means an entity engaged in the retail sale of electricity to end-use customers located within the state, including any of the following: (1) an electrical corporation ... ; (2) a community choice aggregator ... ; or (3) An electric service provider ...”).


51. Id. at 35.


54. Id. at 37.


56. RPS Eligibility Guidebook, at 38.

57. Id. Note that under both scenarios, the electricity must eventually be delivered to California within the calendar year. See id. These transactions are “marked” with what is called a “NERC E-Tag” that tracks the electricity. Id.

58. Id.


60. Id. In a separate Decision 11-01-026, on Jan. 13, 2011, the CPUC also imposed a 25 percent cap on TRECs for Energy Service Providers in California, but declined to impose the $50 per TREC price cap.

61. Id.


64. See id. (discussing that Gov. Schwarzenegger vetoed legislation that increased the RPS percentage to 33 percent due to concerns that the RPS restricts utilities’ ability to purchase out-of-state RECs).


66. See Staff Report at VI-3.


68. See proposed 17 Cal. Code Regs., § 97007(a). The RES would allow for certification in one of three ways: (1) by the CEC based on the current RPS program guidelines; (2) by the CEC under an interagency agreement with CARB based on the RPS program guidelines except for any delivery requirement; or (3) by a CARB Executive Officer, his designee, or a third party contractor.

69. See proposed 17 Cal. Code Regs., § 97005(d); See Staff Report at p. VIII-4.
The authors wish to emphasize that in-state generation requirements, though an important impediment to the growth of a unified REC market, are not the only impediment to such growth. Other state-specific regulations which can impair the tradability of RECs across different RPS regimes include the types of renewable energy resources eligible to produce RECs and restrictions on the capacity and vintage of facilities qualified to produce RECs, among others.


90. U.S. CONST. art. 1, § 8, cl. 3.


92. Complaint, at 3–4, quoting Family Winemakers of California v. Jenkins, 592 F.3d 1, 9 (1st Cir. 2010).

93. Complaint, at 22.

94. Complaint, at 22–23.


98. Id. § 610(b)(1).

99. Id. § 610(b)(2).

100. Id. §§ 610(h)(1), 610(h)(3).

101. Id. § 610(h)(4).

102. The authors wish to emphasize that in-state generation requirements, though an important impediment to the growth of a unified REC market, are not the only impediment to such growth. Other state-specific regulations which can impair the tradability of RECs across different RPS regimes include the types of renewable energy resources eligible to produce RECs and restrictions on the capacity and vintage of facilities qualified to produce RECs, among others.