Addressing Leakage in a Cap-and-Trade System: Treating Imports as Sources

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1. Problem statement

In a supply-side cap-and-trade system with a limited geographic scope and the potential for power supply imports (i.e., a system like RGGI), generators outside the capped region could export power to load-serving entities within the region without being covered by the regional carbon cap. This is called "leakage." This paper also uses the term, "carbon export" to recognize that power imports *per se* are not a problem – it is the *carbon* associated with the generation behind the imports that concerns policy-makers. Leakage raises at least six problems:

(1) Most importantly, imports could undermine the effectiveness of the program by allowing incremental emissions that are not counted against the region's emissions limits even though they are associated with power consumed by capped-region customers, and have displaced capped/counted resources that otherwise would have served that load;

(2) Uncapped imports will have a competitive advantage compared with capped, in-region generation, both disadvantaging local generation and leading to greater reliance on remote sources and transmission links needed to bring that power to the region;

(3) Without the discipline that comes from capping imports in some way, outside generation could displace energy efficiency and incremental, cleaner generation within the capped region;

(4) Allowing generators in non-RGGI states to sell power to RGGI-state LSEs erects an additional political barrier to the geographic expansion of RGGI. Once those non-RGGI generators have the commercial advantage of selling power without the necessity of retiring allowances, they would be more likely to resist losing that advantage. And if they were asked to join a RGGI in which leakage *remains* unaccounted-for, they would be further disinclined by knowledge that generators in other border states could now sell into their backyards at a commercial advantage.[1]

(5) Failure to address leakage makes it more difficult to create a large consumer allocation or auction of allowances. When generators are disadvantaged by having to compete with outside generators who face no carbon constraint, policymakers may be reluctant to require

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[1] For example, generators in Pennsylvania would lose their exporter's commercial *advantage* by joining RGGI, and would further suffer the commercial *disadvantage* of competing with Ohio generators, who now could sell into Pennsylvania without needing the allowances that the Pennsylvania generators would now be required to possess.

them to purchase their allowances in the first place. Generators are likely to argue that having to purchase allowances places them at further competitive disadvantage.

(6) Finally, emissions leakage has the effect of discounting, and adding uncertainty to, the value of RGGI carbon credits. This weakens the value of the RGGI "currency," and will impede RGGI's ability to trade credits with other cap-and-trade schemes in the United States, or with international programs, such as the European Trading System.[2] In this regard, it makes little sense to adhere to strict standards for RGGI-approved offsets while imposing no standards at all on the "free" allowances permitted by uncontrolled leakage.

2. Definitional question: what counts as leakage?

An initial question is defining what counts as leakage under RGGI. RGGI rules could take a range of approaches:

(a) Leakage is incidental to operation of the power grid, and won't be counted at all unless, over time, monitoring finds it to be a large problem.
(b) RGGI causation -- RGGI will count and attempt to control only incremental imports that are found to be *caused by* creation of the RGGI system (requiring modeling and causation analysis for any changes in generation and imports patterns);
(c) Changes in *net imports* -- RGGI will count all changes in net imports from a baseline period, crediting RGGI generation that is exported from the region against outside generation that is imported;
(d) Changes in *total imports* – RGGI will count as leakage any increase in carbon exports associated with imported power.

Since the goal of the RGGI program is to achieve verified GHG reductions in the real world, (c) and (d) above are the obvious preferred approaches to measuring and accounting for leakage. Approach (d) is somewhat better at meeting this goal, since it would ensure reductions in in-region generation and also control for external generation serving in-region load.

3. Four practical realities:

(a) It is very difficult to try to model or predict leakage years in advance. Leakage modelers often try to guess how big leakage will be by modeling the price of carbon credits and asking whether the rate differential would be large enough to inspire cross-border arbitrage. This is relevant information, but quite incomplete in modeling potential leakage over more than a decade. All else equal, it's reasonable to assume that high carbon prices would add leakage pressure. But there are many other non-price factors that can also greatly affect the amount of leakage: e.g., physical availability of new transmission capacity; ease of siting new generation in

[2] Knowledgeable observers in California have already noted this problem and pointed out that trading between California and RGGI may not be possible for this reason. California's new legislation mandates a power sector cap that accounts for imports, and requires the implementing rules to "minimize leakage." Allowing credit trades with a system that does not control leakage would be allowing indirectly that which is directly barred.

coal regions vs. siting a new coal plant within RGGI; the desire of LSEs to add stable-priced coal to a mix that's too heavy in more volatile gas; improved capacity factors at existing external fossil units; ISO reliability rules that give capacity revenues to existing generators; and so forth. Factors like these could lead to additional leakage without any large price differential due to carbon credit costs.

(b) Powerful external influences will affect leakage, and thus the success of the RGGI program. In the spring of 2006, AEP announced a proposal to build a major new transmission line from West Virginia to New Jersey. Other major links, not reflected in RGGI's plans or model runs, are also on the drawing boards across the Mid-Atlantic and Northeast states. Meanwhile, the Department of Energy is considering designations of national interest transmission corridors to promote new transmission investments even if they are opposed in state and local siting decisions. The transfer capability offered by these potential lines could have a significant effect on the success of the RGGI program. While the AEP proposal is an eye-opener, it's important to understand that it does not require anything of this magnitude to punch a big hole in the cap (see (b) below). One of the reasons it's hard to predict is that l**eakage rates will be affected by many things**, not just cap-caused price differentials between in-region and external resources.

An additional factor is the so-called "resurgence of coal" taking place across the nation, including many states bordering the RGGI region. In 1994, the National Energy Technology Lab assembled a list of all of the planned new coal plant proposals announced in the nation. At that time developers had announced plans for 94 plants, totaling 62 GW in capacity, at a projected cost of $72 billion. In September 2006, NETL updated this list. Developers are now proposing *154 new plants*, with capacity totaling 93 GW, at a projected cost of $137 billion. – this is an increase in planned coal plant builds of 50% in just two years. Almost 7,000 MW of that capacity is proposed to be built in states bordering RGGI.[3] These large numbers are driven in part by the recent increases in the price of natural gas. Some observers believe that they are also influenced by a "race to grandfather" coal builds before the imposition of a national carbon management plan, which is increasingly expected by industry leaders. One doubts that the architects of RGGI wish to encourage that race by permitting new coal plants to sell into the RGGI region without any carbon responsibility.

(c) Unfortunately, it only takes a small shift in purchasing patterns to result in quite large leakage percentages. Suppose "leakage happens." Is this a big deal?

Considering the safety valves added to the RGGI program design in late 2005, leakage may not rise to the 70% range suggested in some earlier model runs. But it might, and it is possible that it could easily turn out to be in the 40% to 60% range if not controlled. On the optimistic side, the new safety valves mean lower carbon prices, meaning lower in/out price differentials and thus less "pull" on imports. On the pessimistic side, if power purchasers are choosing among (a) in-region gas with potentially volatile prices and uncertain availability, (b) in-region renewables—

[3] Scott Klara et al, National Energy Technology Laboratory, "Coal's Resurgence in Electric Power Generation – Proposed New Plants" OCES 2-24-2004 and 9-29-2006.

stable, but intermittent and higher-priced, and (c) imported coal, available long-term at more stable prices, their choice will be influenced by more than just the carbon price differential.

So how much new coal is enough to worry about? The answer is "not much." Here is how critics might look at it:

(i) RGGI is reducing total emissions in stages up to 10% over 10 years (2009-2018). Total reductions are roughly 55 million tons over that 10-year period (5.5 million less in 2015, rising to 22 million less in 2018, for a total of 55 million.)
(ii) Thus, if we lose 55 million tons over 10 years to new imports, RGGI will "give back" ALL of the total program reductions.
(iii) 55 million tons = ~55 million MWh of new coal imports, or on average 5.5 million MWh per year over a decade. Actually, we only have to lose 55 million tons over 13 years -- any new imports in the period 2006-2009 just make the situation worse.
(iv) RGGI's total power consumption (7 states) was roughly 280 million MWh in 2000, projected by ICF to rise to about 375 million MWH by 2019.
(v) 5.5 million MWH is just 1.5% to 2% of total sales in those years.

So: **What this means is that all it would take is new coal imports equal to 1.5% to 2% of the region's power supply over the 10-year period to offset 100% of the actual reductions attributed to RGGI.** Since load growth alone is projected to be about 1.2% to 1.4% per year, an increment as small as 1/8th of load growth served by new coal imports could erase *all* of RGGI's planned reductions or about half of the estimated difference between BAU and the cap.[4]

(d) Motivation and causation are irrelevant. Sometimes conversations on leakage turn to ideas of causation—e.g., if RGGI did not "cause" the new imports or emissions to occur, then the RGGI program needn't find a way to manage them. This is just plain inconsistent with the idea of a sector cap. Remember that imports are on-sector activities, not off-sector activities outside of the cap system where additionality is important to consider.

By way of analogy, suppose someone suggested giving offset credits for in-region energy efficiency or renewables on the ground that RGGI has "caused" some additional EE or RE to occur. RGGI designers would rightly say that this would lead to double counting unless the cap were then reduced and the associated credits retired. Importantly, that answer would be the same for ALL EE and RE in the region, including both "RGGI-inspired" and "independent" resource additions. In other words, we would not care if the EE or RE in question were "caused" by RGGI or not—either way, it is not entitled to offset credits. Under a cap, tons are tons, and we don't have to try to read into the hearts and minds of the emitters and reducers in order to measure them.

[4] Milder notes: (a) if we measure the percentage lost to leakage against the projected BAU baseline, which grows higher than the 221 million ton cap, the leakage percentages will be smaller. But critics are likely to focus on what leakage takes back from the 10% reduction; and (b) MWh imports from lower-emitting sources will of course have a smaller impact than increased coal imports. With the math above, even importing 1.5% to 2% new gas into the region could take back 50% of the overall reductions from RGGI.

Similarly for imports. The tons associated with imports either go up or go down, and we can measure this. We don't have to know the reasons, or the motivations of the buyers and sellers, (or, more obliquely, of the system operators who amend congestion policies and capacity rules), in order to measure changes in imports. It doesn't matter *why* leakage happens, only *if* it happens.[5]

Conclusion: ignoring leakage unless it is found to be "caused" by RGGI is inconsistent with cap-and-trade fundamentals, and it allows double counting. Besides, causation is almost impossible to determine and, therefore, as a practical matter, should not be the basis for a regulatory mechanism. RGGI can and should deal with this issue simply by measuring and accounting for changes in imports. It is unnecessary to debate predictions, or to determine causation, and it forestalls serious program erosion.

4. Potential leakage solutions

There are several ways to approach the leakage challenge, ranging from very general influences to specific and direct accounting approaches. Choices include:

(a) Simply **monitor** leakage and deal with it later if it seems to be a problem.

(b) Create **carbon performance standards** for LSEs to forestall carbon exports;

(c) Promote **complementary energy policies** to lower in-region demand for power generally, and especially for fossil power, thus reducing "pull" for imports ;

(d) Create **regional or statewide set-asides** to offset leakage at the program level, making generators or consumers "pay" for leakage out of their allocations; and

(e) **Assign carbon responsibility to importers or load-serving entities (LSEs)**, requiring them to retire credits to account for carbon imports due to their power purchase decisions.

There are pros and cons to all of these options, and a thorough review will probably look at all of them. This white paper focuses on the two options that have attracted the most recent attention: Option (b) **carbon emissions performance standards** for generation acquisitions, and Option (e), counting and **treating carbon exports on the same basis as local emissions**, which is the most direct way to deal with the import leakage problem. These options are discussed in sections 5-8 below.

[5] Note: If RGGI's goal is to reduce emissions to a level that is X% below *that which it would have otherwise been (including imports)*, then, in an effort to determine a baseline, everybody can spend the next decade arguing over what imports would have been, and where they would have come from. Although this is not a useful way to approach the problem, even here we would have to track and measure imports against that projected baseline in order to employ a cap system, and here again, "causation" would be beside the point.

5. Carbon Emission Performance Standard

Over the past several months, the California PUC has been developing a new Emission Performance Standard for regulated load-serving entities, which would bar major new financial commitments by LSEs to power facilities and contracts that emit more CO2 per MWh than a well-performing natural gas combined-cycle power plant. The pending Rule would apply equally to in-state and out-of-state facilities, but only to the subset of power supply acquisitions that are (a) new commitments, (b) over five years in length, and (c) for power from baseload facilities. Blending emission rates across multiple sources would not be permitted, and the standard does not apply to most elements in LSE resource mixes today.

The California EPS is thus *not* a portfolio standard, but a binary threshold standard that either permits or forbids a major new long term resource choice. It would be applied on a "gateway" basis, at the time a contract or facility is proposed, rather than continually over its life. The PUC's suggested approach to this standard was ratified in basic terms by the state legislature in August 2006 with the passage of SB 1368. The new law mandates such a rule by the PUC, and through the California Energy Commission, would apply it also to public power LSEs in California.

Press accounts on this proposal suggest that some developers of coal-fired facilities in the interior West are rethinking their projects now that they might not be able to secure significant long-term sales into the California market. There has been some discussion among RGGI decision-makers as to whether the adoption of a California-style EPS by RGGI states would be an appropriate and effective means to combat leakage in the RGGI region.

Evaluation. In general, a California-style EPS for major new power supplies is unlikely to be of much help in combating leakage in the RGGI region, and it has structural limitations that do not make it a good complement to RGGI's cap and trade program.

On the positive side, if each RGGI state were to adopt a binary gateway EPS, it would put general downward pressure on carbon emissions, including emissions associated with power imports. This might at least eliminate the prospect of major new long-term high-emissions contracts between RGGI-state LSEs and out-of-RGGI generators. The EPS is also relatively easy to administer, since it applies to few supply options, is applied only once in the life of each resource commitment, and the standard yields a clear-cut "go" or "no-go" decision. Strightforward, non-discriminatory application to in-region and out-of region commitments is also possible.

These positives are outweighed by some significant limitations.

To begin with, the EPS does not restrict growth in total emissions from power serving California. Combined cycle plants can meet the standard and gain approval under it. Other, higher-emitting resources can sell to California LSEs under contracts shorter than five years in term, or for any term if they are intended to operate at less than a 60% annual capacity factor (i.e., they are not

defined as "baseload facilities" under the statute). And there is no limitation on emissions from *existing* utility-owned units or *existing* contracts. Finally, by its very nature, an EPS is not a cap.

If applied to RGGI, an EPS of this sort is likely to miss many of the facilities, contracts, and sales that would drive leakage in the RGGI region. The region's advanced power markets clear a large number of MWhs on a short-term basis, and without regard for whether they are "baseload" units or something else. And a very large fraction of acquisitions by default service providers, standard offer providers, and competitive suppliers are for terms much shorter than five years. Since small increases in imports could erode a large fraction of RGGI's gains, an EPS geared only to major new commitments would not necessarily protect the RGGI program from excessive leakage. On the other hand, an EPS that applied to a large number of individual, smaller acquisitions would be more complicated to administer without having any of the advantages of trading or averaging across multiple sources.

Second, while relatively easy to administer, the EPS still requires the collection of average emissions data from neighboring power systems in order to assign emission rates to system power contracts or other arrangements that do not specify particular generating units. Such data are also needed to administer more flexible anti-leakage policies (see the following section); adopting a blunt EPS does not avoid this measuring and attribution requirement.

Third, one of the fundamental limitations of a binary go/no-go standard for individual facilities is that it does not permit trading among sources, even where, taken together, they could meet the prescribed standard. While this is acceptable for an interim Rule pending adoption of a cap and trade program, on a permanent basis it would exclude any economic gains that could come from blending power sources, trading across contracts, and so forth. This is not consistent with RGGI's approach to carbon management generally, which is to promote trading as a means to lower total program compliance costs.

The EPS was developed by the California PUC as a means to forestall "backsliding" and attempts to grandfather high-emission power acquisitions by LSEs pending adoption of the state's future cap and trade program for the power sector. It is intended not as a permanent Rule, but just as a blunt tool to protect the status quo while the anticipated load-side cap system is developed.

Finally, those considering adopting an EPS-style rule for RGGI should be aware that it could not be applied solely to imports. The California EPS applies on an even-handed basis to all new resource commitments, wherever located. This evenhanded treatment is desirable on policy terms, and under the commerce clause of the US constitution it is also required. Within RGGI, an EPS rule intended to limit major new LSE commitments or renewals to imported high-emissions power would also need to apply to similar commitments with the RGGI region's existing and proposed fossil fleet. Thus, high-emitting units within RGGI states, even if permitted to run under cap and trade when they have acquired adequate allowances, might nevertheless be barred by the evenhanded application of the EPS.

For these reasons, a binary EPS is not highly compatible with RGGI's cap and trade system on a long-term basis, and is not the most effective means to control leakage.

6. Recommended approach: Counting and accounting for imports as sources of carbon emissions

The most direct means of controlling leakage under RGGI is to (a) count emissions associated with imports serving RGGI load, and (b) treat these emissions as sources under the RGGI cap. Simply stated, this policy would extend the cap to cover power supply that is either generated within the RGGI region ***or*** serving load within the region.

Essentially, for the purposes of the cap-and-trade program, states would treat imported power in the same fashion as power generated within the RGGI region. Legal responsibility for the emissions associated with imported power would lie with the load-serving entity (LSE) within the RGGI region that has purchased and delivered the power to in-region customers. Supervision of LSEs for this purpose could be done in each state by the same agencies that supervise implementation of Renewable Portfolio Standards and other power portfolio attributes (usually the state utility regulatory commission) or it could be assigned to the air agency implementing other aspects of RGGI.

7. Essential elements of the proposal The key features of the proposed approach are:

a. General requirement. On an ongoing basis, the RGGI model rule should require each RGGI state LSE to certify that adequate carbon credits have been retired to cover the emissions associated with each MWh of its retail sales to RGGI-state customers. For power supplied by RGGI units, the LSE can simply pass on a certification from the generators that allowances were retired by them as required by RGGI. For imports, either the LSE or another market participant (e.g., generator, power broker, credit broker) will need to retire the credits.

   Conceptually, imported power can be thought of as though it were being generated at the LSE's delivery location or metering point. The regulated entity for the purposes of this aspect of the RGGI program would be the LSE – either the distribution company for standard offer or franchise service or the competitive supplier, depending on the situation in each state. These are state-jurisdictional entities within the RGGI region.

b. RGGI cap levels and apportionment. Treating imports as sources is compatible with a supply-side cap-and-trade system that focuses mainly on capping emissions from sources located physically within the RGGI region. To extend the cap to imports, the initial caps and goals for the RGGI region (and individual states, if applicable) could be set at levels that include the emissions associated with historic imports on the same basis and timeframe as historic in-region generation. Thus, for example, the New Jersey apportionment would include both its historic local generation and its historic level of imports. If RGGI Principals do not wish to alter the existing RGGI MOU, cap, and state-

by-state apportionment, the allowances needed to accommodate imports could be separately authorized under a separate MOU.

c. Equality of treatment. The baseline for apportionment purposes should be set, if at all possible, so as to closely match the baseline period used to set the in-region generation cap. The cap's structure and rate of decline should also match the curves set for in-region generation – or, if it is different, it should not discriminate against out-of-region sources.

d. Allocation to LSEs. States could take different approaches to allocating allowances to cover imported power. They might be allocated directly to LSEs in proportion to their historic imports baseline (protecting high-quantity importers), or they might be allocated to LSEs in proportion to total load (rewarding those with cleaner average mixes). Alternatively, a state might choose to allocate them to distribution companies or other consumer trustees, who would then sell them to out-of-RGGI generators or to LSE importers, using the revenue for customer and public benefits.

e. Trading and transferability One advantage of this approach, compared with the EPS approach discussed above, is that trading would be permitted among sources and among LSEs in order to meet the cap objectives. LSEs that import less power (or cleaner power) than their baseline allocation can sell excess credits, while LSEs or their suppliers needing more credits can buy them in an open credits market.

One interesting question is whether a RGGI "imports ton" ought to be able to trade on even terms with a RGGI "generator ton," or whether there should be two types of credits that do not trade with each other, like RPS RECs and NOx credits. While this may still require some practical analysis, for commerce clause purposes it seems highly desirable to permit trading on even terms among all sources in the LSEs power supply mix.

Moreover, allowing trading between RGGI emissions and imports emissions is consistent with the purposes of RGGI.[6] If a RGGI LSE imports less power than its historic baseline, and sells its extra credits to a RGGI unit that is increasing emissions, total emissions associated with the RGGI power sector[7] remain unchanged; increased local emissions are offset by decreased leakage. The same is true if the directions are reversed.

8. Assigning Carbon Attributes to Imports

Determining the carbon contribution of power generated outside of a capped region is not as straightforward as it might seem. A rule that assigns carbon attributes solely on the basis of

[6] Provided that there is adequate discipline in the baseline determination, and in measuring and verifying emissions associated with imported power.

[7] This is also consistent with the whole idea behind controlling leakage in the first place, which is a recognition that the RGGI program ought to manage all emissions serving load in the region, not just the portion from smokestacks located physically in the region. Since the underlying power can trade freely between inside and outside sources, the emission credits attached to the power should trade freely also.

power units *assigned to a sale* in a bilateral contract will likely understate the actual contribution caused by the sales in question. This is because it would be advantageous to sellers to contractually assign clean power to export sales into RGGI, while increasing carbon-intensive power assigned to the non-RGGI sales, without necessarily improving the generator's emission profile at all. As policymakers setting standards for green pricing programs and renewable portfolio standards have learned, it is relatively easy to "greenwash" power sales when not all sales are subject to the regulation in question. RPS and green power rules have already been developed to address this problem, so power sector regulators have some experience dealing with the issue. The following rules could provide a more accurate basis for assigning carbon responsibility to imports:

a. As a general matter, imports should be deemed to have the characteristics of the average of all power generated in the exporting control area. Alternatives to this rule can be discussed: they include using a larger region as the exporting region (e.g., the entire power pool rather than the control area) or assuming the import was generated at the margin of all generation in the exporting region. For imports from PJM, it might make sense to use the weighted average emissions of all PJM units located *outside* of the RGGI states.

b. One exception to the "average emissions" rule can be permitted: attributes can be tied to bilateral contracts when the generation is (a) "new and incremental" in the exporting region, and (b) sold through a bilateral contract to a RGGI LSE. While this rule could apply to any incremental generation, it would probably be invoked only to encourage creation of new clean resources outside of the RGGI region. (Rules of this sort have been used for both RPS and green power programs.)

c. Spot market sales must also be addressed, especially those that will occur on a routine basis among entities within PJM on both sides of the RGGI-region boundary. The simplest way to deal with such spot purchases is to assign them a pro-rata fraction of all spot-market imports in each hour, and to assign to those imports the average system characteristics of the non-RGGI units in the PJM region.

d. The RTOs within the RGGI region would need to calculate and track emissions associated with imports into their systems, and provide those data to state regulators supervising the cap-and-trade system. While not a simple task, this challenge is consistent with the purposes of the GIS and GATS tracking systems in place or being developed in the region's ISOs.

9. Legal Issues

Do states within the RGGI region have the necessary authority to extend a cap-and-trade system to imports? There are at least three legal questions involved:

a. First, does the proposal impermissibly burden interstate commerce and violate the commerce clause of the US constitution?

As a general matter, states can impose police power restrictions on goods and services in interstate commerce when state regulation serves a legitimate state interest, and does not discriminate against out-of-state commerce. This proposal, like renewable portfolio standards and green pricing rules, seems to satisfy those tests.

The text above discusses how an anti-leakage policy can be designed so as to treat in-state and out-of-state generation and emissions on an even-handed, non-discriminatory basis. It is understood that these rules affect interstate commerce differently from a RGGI that does not control leakage at all. Under the "dormant commerce clause" of the US constitution, states may regulate so as to affect interstate commerce, provided they do not discriminate against out of state commerce and the impact on interstate trade is incidental and the public benefits outweigh the burden on commerce:

> "Where the statute regulates evenhandedly to effectuate a legitimate local public interest, and its effects on interstate commerce are only incidental, it will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits," *Pike v. Bruce Church, Inc.* (US Supreme Court 1970)

Matters of "legitimate" local concern to states, e.g., "to protect the health and safety of its citizens and the integrity of its natural resources," can justify imposing burdens on interstate trade, providng that the means chosen are reasonably necessary to achieve the public goal. *Maine v. Taylor*, 106 S.Ct. 2440, 2454 (1986). In this case, reducing CO_2 emissions will provide both environmental and public health benefits to RGGI states and it is reasonably necessary to include imported power within the cap in order to achieve these reductions. In addition, controlling greenhouse gases provides external benefits to non-RGGI states; this is not an example of parochial interests seeking to avoid environmental harms by imposing them on others – quite the opposite!

As for discrimination, a cap-and-trade system that does NOT include imports actually discriminates—in favor of imports and *against* locally-generated power. By treating imports as sources on the same basis as RGGI-region power, the proposal is non-discriminatory in intent and effect. In order to have a non-discriminatory effect, however, it is important that the initial cap and allocation be set so as to include imported sources from the outset, on the same basis as in-region sources. Moreover, there should be no pre-set limit on imports; import-related carbon and in-region carbon can be traded on an even basis, and the ratio of local generation to imports can change freely over time.

b. Second, is state jurisdiction preempted by FERC under the Federal Power Act?

Electric power transmission and wholesale power transactions are FERC jurisdictional under the FPA. In the absence of a FERC rule that would address the carbon content of RGGI-region imports (a fair assumption), it is important to structure the RGGI model rule so that the regulation here is not a restriction on transmission or on wholesale transactions *per se*. For this reason the proposal is structured as a requirement on LSEs, and then only on their sales to

ultimate customers within the RGGI region. It is not a restriction on transmission or on wholesale sales into the region. A power transaction might, for example, pass through a variety of middlemen before it is sold to ultimate customers. The carbon credit requirement only applies to the last (retail) seller to retail customers in the RGGI region. That sale is state-jurisdictional. The extensive legal analysis supporting RPS and many other state requirements on retail sales would apply here.

c. Do individual states have the authority needed to manage the carbon content of imported power purchased by regulated LSEs?[8]

Legal research is needed to answer this question for individual states. First, state law should be examined to determine whether state environmental regulators could impose these restrictions on LSEs as a necessary component of a source-based regulatory scheme. If this is not possible in particular states, state law should be examined to determine whether state PUCs would have that authority, either on their own or as regulatory partners with state environmental agencies.

As a general matter, the authority of PUCs to regulate retail sales in the public good is quite broad. Treating imports as sources under a broad carbon management plan could be found to serve economic, environmental, and reliability purposes (e.g., it is not in the interest of any state to create a regulatory environment that discriminates against local generation in favor of long-distance imports). Moreover, even in states where the independent environmental jurisdiction of the PUC has been limited, it may be possible for the PUC to assist environmental regulators to implement a comprehensive management plan. These issues will require careful state-by-state review.

[8] Whether states can extend their regulatory schemes to include carbon under the Clean Air Act and relevant state law is not addressed here. This is a basic proposition of the RGGI program, and has been researched elsewhere. The question here is whether, in a supply-side cap-and-trade system, carbon caps could be extended to cover imports as an additional category of sources.