LEVITAN & ASSOCIATES, INC.

To: J. Platts, M. Babula
From: E. Cool, A. Hauptman, A. Clowes
Re: RGGI Compliance Strategies in New England
Date: April 14, 2006

Background

Four of six New England states -- Maine, New Hampshire, Vermont, and Connecticut -- signed the Regional Greenhouse Gas Initiative (RGGI) MOU on December 20, 2005. The MOU is an agreement to stabilize CO_2 emissions from electric generators in seven states at current levels from 2009 through 2014, followed by a 10% reduction in emissions by 2019. Regional emissions from all of the MOU states (including New York, New Jersey, and Delaware) would be capped at 121.3 million tons of CO_2 during the stabilization period.[1] The total cap has been distributed among the seven RGGI states, in accordance with Table 1. Each state's budget automatically declines by 2.5% per year for years 2015 through 2018. Each state may allocate allowances from its CO_2 emissions budgets in a manner it determines to be appropriate. However, all of the states agreed in the MOU that 25% of their allowances will be auctioned with the revenues earmarked for consumer benefit and/or strategic energy purposes. Each state will determine how the state auction is conducted and who may participate.

Table 1 – RGGI State Budgets

	Base Annual CO_2 Budget (short tons)
Connecticut	10,695,036
New Hampshire	8,620,460
Vermont	1,225,830
Maine	5,948,902
New York	64,310,805
New Jersey	22,892,730
Delaware	7,559,787
TOTAL	**121,253,550**

On March 23, 2006, the RGGI Staff Working Group released a Draft Model Rule for public comment. Once finalized, the Model Rule will form the basis of individual state regulatory and/or statutory proposals to implement the program. The comment period will run for a period of 60 days, closing on May 22, 2006. A final rule is anticipated to be issued in early July 2006.

ISO New England (ISO-NE) engaged Levitan & Associates, Inc. (LAI) to solicit information from generators, regulators, and other stakeholders to identify the anticipated RGGI compliance

[1] On March 31, 2006, the Maryland General Assembly approved a bill requiring the state to join RGGI, and the Governor is expected to sign the bill.

strategies for a range of generator cohort groups. The purpose of this effort is to inform ISO-NE as to the likely compliance methods to be implemented by generators, and potential risks these may present for maintaining system reliability. Using this information more broadly, ISO-NE will be able to evaluate the potential impact of RGGI on system reliability and resource adequacy. In addition, this information may suggest areas where ISO-NE might comment on the RGGI Draft Model Rule. Although Massachusetts and Rhode Island are not currently RGGI MOU signatories, generators in those states are included in the scope of this research. We anticipate that Massachusetts and/or Rhode Island will adopt the RGGI program before it begins, or that Massachusetts' existing regulations governing CO_2 emissions from six large, older power plants will similarly impact their operation.[2]

LAI conducted informal outreach to representative generators in New England who are participants in the RGGI Stakeholder Group. We contacted state regulators who are members of the Staff Working Group responsible for developing the program, and obtained input from several policy advisors to the Staff Working Group. Written stakeholder comments and presentations posted on the RGGI web site (www.rggi.org) or provided directly to us were also incorporated in this review. LAI also relied on our market knowledge and proprietary in-house models to assess RGGI Staff Working Group models and market forecasts.

Critical features of the RGGI program are still undetermined. For example, the Staff Working Group is still attempting to address how imports would be treated; one concept is to require load to cover allowances for imports. Importantly, it is left to each state to determine how it will allocate its budgeted allowances. Some states, such as Vermont (and New Jersey), are leaning toward auctioning 100% of the total state budget for public benefit purposes. Other states are considering freely granting to the generators 75% of the state's allowance budget not set-aside for public benefit. Allocations may be based on historic fuel input or net electric output. Other alternatives under consideration are to allocate allowances to load or to the transmission owners. A set-aside mechanism for new fossil-fueled generation projects would also need to be established in each state. The state programs implementing RGGI will require statutory authority and/or administrative rulemaking, and therefore the state-specific allocation processes and final program elements are unlikely to be finalized until mid-2007, perhaps later.

Given these program uncertainties, as well as the fact that the RGGI allowance market is not yet in existence, generators currently find it premature to fully develop workable compliance strategies. The generators contacted by LAI were forthcoming but offered only generalized compliance strategies for generic plant types, with the proviso that the company identity not be documented. Most generators declined to provide plant-specific compliance information. Plant or project-specific information provided in this memo is limited to information already in the public domain. During interviews, all of the industry representatives were eager to express their concerns and opinions about the RGGI program and the Draft Model Rule.

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[2] The Massachusetts plants affected by 310 CMR 7.29 are: Brayton Point, Canal Electric, Mt. Tom, Mystic Station, Salem Harbor Station, and Somerset Station. These regulations, and the proposed amendments to implement the CO_2 program, have cap-and-trade and offset (credit) features similar to RGGI. The Massachusetts regulations affect fewer facilities and include more conservative "safety valve" mechanisms for allowance pricing.

Draft RGGI Model Rule

The RGGI program is applicable to fossil fuel-fired generators 25 MW and larger. Each affected facility must cover its CO_2 emissions with allowances over a three-year compliance period. The first compliance period begins January 1, 2009 and ends December 31, 2011. The allowance transfer and true-up deadline is March 1 for the three-year compliance period ending the prior December 31. According to the Draft Model Rule, facilities may use allowances banked from a prior compliance period to meet the current period requirements. Penalties apply for shortfalls in allowances not acquired by the true-up deadline. Prior to January 1, 2009, facilities may also undertake projects that create early reductions, and bank those allowances without limit until the start of the program.

As envisioned by the Draft Model Rule, offsets are intended to moderate allowance prices. Offsets are created "above the cap" through a project, outside of the RGGI sector, that creates real, additional, verifiable, enforceable, and permanent reductions in greenhouse gas emissions. A facility may cover only up to 3.3% of its emissions obligation over the three-year compliance period with CO_2 offset allowances unless certain allowance price triggers are exceeded. Initially, offset allowances derived from projects in RGGI states create one CO_2 allowance, but it will take two offsets from U.S. projects outside of the RGGI states to create one CO_2 allowance. However, if the average price of a CO_2 emission allowance remains above the offset trigger of $7.00/ton, offsets may be used from projects across North America at a 1:1 ratio and each generator may use offsets to cover up to 5% of its emissions. A "safety valve offsets trigger" at $10.00/ton would expand the geographic availability of offsets to include international projects and a generator would be allowed to use offsets to cover up to 20% of its emissions. If a safety valve trigger occurs, the compliance period would also be extended for up to three additional years. There is a reset provision associated with each trigger that returns the program requirements to the initial conditions in the subsequent compliance period.

By design, RGGI is intended to be more burdensome for less CO_2-efficient plants, such as older coal-fired steam turbines, relative to more CO_2-efficient plants, such as new gas-fired combined cycle plants. CO_2 efficiency can be defined as the amount of CO_2 emitted per kWh generated and depends on both the fuel type and the unit heat rate. The RGGI program is expected to benefit and encourage investment in renewable and other non-emitting generation.

As a benchmark, LAI estimated the impact of forecasted CO_2 allowance costs relative to other variable operating costs for generic plants. The Staff Working Group forecasts that by 2024, CO_2 allowance prices will range from about $2.50 to $6.50/ton (2005$), depending on the modeling scenario. As illustrated in Attachment 1, an incremental cost of up to $6.50/ton of CO_2 would narrow the gap in the cost of delivered fuel plus SO_2, NOx, and CO_2 allowances among incumbent coal, oil, and gas-fired plants, but it would not invert traditional fuel price parity relationships (all else being equal).[3] The variable cost of delivered fuel plus emission allowances for coal would approach the variable cost for gas only if the CO_2 allowance price exceeds

[3] The variable cost comparison is based on LAI's delivered fuel price forecast.

$60/ton (all else equal.) However, on an output basis, which incorporates the heat rate differences among cohort groups, if the CO_2 allowance price were to exceed $19/ton (2005$) the variable cost for an older coal steam turbine (assumed heat rate of 11,000 Btu/kWh) per unit electric output would approach the variable cost for an existing gas-fired combined cycle plant (assumed heat rate of 7,700 Btu/kWh) per unit electric output.[4] Gas usage would be expected to increase relative to coal or oil as the CO_2 allowance price increases. With increasing allowance cost, the economics of pumped storage hydrogeneration will also be impacted, requiring more fossil fuel on peak.

Compliance Alternatives under the RGGI Program

Market-based cap-and-trade programs such as RGGI are intended to provide generators with a range of compliance options so that each facility can elect the option that makes the most economic sense. Unlike the NO_x or SO_2 allowance trading programs, however, there is no proven and cost effective "end-of-pipe" compliance alternative for CO_2, which somewhat limits the compliance flexibility offered under RGGI. As envisioned by the Draft Model Rule and the MOU, the following are the available compliance strategies:

<u>Trading Mechanisms</u>

- A facility can acquire allowances, either through initial allocations or auction, or in a secondary market, to cover all of its CO_2 emissions over the three-year compliance period. As proposed by the Draft Model Rule, each state will allocate allowances for the first four years of the program prior to January 1, 2009.[5] We have observed in other trading programs that prior to compliance milestones, allowance prices have exhibited price spikes and increased volatility. If the CO_2 market becomes workably vigorous, we anticipate that a variety of risk management products will emerge so that generators can hedge their forward allowance requirements.

- A generator can obtain qualified offsets up to the prescribed limit (3.3% of the facility's annual CO_2 emissions unless a price trigger occurs, then the limit would increase to either 5% or 20%).

[4] It is worth noting that the federal Clean Air Mercury Rule envisions a trading program for mercury allowances, applicable to emissions from coal plants. If such a program is implemented, it would further reduce the fuel price advantage currently enjoyed by coal generators, and likely increase the usage of gas across the system.
[5] Exactly how this provision would be implemented in a state that auctions 100% of its budget allocation is unclear.

<u>Operational Strategies</u>

- Generators may undertake early reduction projects, such as improvements to plant efficiency, and bank those allowances. This strategy would only be available until January 1, 2009, when the first compliance period begins.

- Generators who have or install dual fuel capability may manage allowances by fuel switching. Dual fuel plants currently use this approach for managing NO_x allowances throughout the year.

- Biomass co-firing is an option for some coal plants.

- Generators may curtail output/reduce their capacity factor.

- Asset owners may retire unit(s).

Generator Feedback

Industry participants we contacted are universally concerned about the uncertainties and inherent tensions in the program. The RGGI Staff Working Group and its policy advisors believe that RGGI is a modest program, which will have minimal impact on retail electricity prices, the regional economy, or shareholder value of generation assets. Simulation modeling conducted by NYSERDA and ICF Consulting on behalf of the Staff Working Group supported those conclusions.[6] LAI concurs with most industry participants that the modeling is based, in part, on some very optimistic assumptions, and therefore the model results must be considered in that light. Specifically, the base case model postulates that all renewable portfolio standard (RPS) programs currently promulgated in the RGGI states will function fully as designed, requiring a substantial amount of renewable generation to be sited, financed, and commercially operable. The base case model also assumes that each state's conservation, energy efficiency, and load management targets and initiatives will be fully achieved. Based on these input assumptions, the models reveal that meeting the RGGI cap requires a substantial amount of new wind capacity, and will result in significant leakage (imports) from non-RGGI states. These modeling results and the significance with respect to capacity buildout and resource adequacy are discussed more fully in Attachment 2.

With respect to anticipated compliance strategies, the generators stressed that each firm's compliance strategy will depend not only on the generation technology and fuel of individual

[6] Prior to implementation of the EU greenhouse gas market, modeling suggested that EU allowance (EUA) prices would be in the range of roughly €7 to €10/tonne for the base case scenario. Although the supply and demand fundamentals are materially different in the EU, it is noteworthy that EUA prices have actually exceeded €28.00/tonne and tend to follow fuel price fluctuations. Since the U.S. is not a Kyoto Annex I country, RGGI allowances are not fungible with EUAs. However, EU Certified Emission Reductions (CERs) under the Kyoto Clean Development Mechanisms may be eligible as RGGI offsets if the $10.00/ton Safety Valve Offset (Stage 2) trigger is exceeded. Evolution Markets, LLC recently reported a trade for CERs indexed to the price of EUAs.

plants, but also on contractual arrangements and characteristics of the entire portfolio. These distinctions are identified below.

- Existing gas-fired generation – These generators indicate that they expect to acquire allowances through the initial allocation (as granted or through auction), supplemented as needed from the market, to cover all emissions. Generators will manage these allowances as they currently do for NO_x and SO_2, utilizing forwards and hedges as appropriate. Generators expect that these plants, despite the incremental costs for allowances, will remain on the margin for the majority of hours. Dispatch factors are expected to increase by "a few percent."

- Existing dual-fuel (gas/oil) plants – Owners of incumbent dual fuel steam turbine plants report that they expect to burn more gas under RGGI. These generators will utilize their initial allocation of allowances and acquire additional market allowances and risk management products, as needed.

- Coal and oil plants – Owners of incumbent coal-fired and oil-fired generators report that they expect to utilize allowance allocations, acquire market allowances, and utilize risk management products, as the market develops. However, generators have not yet determined how this will be managed across their fleets over a three-year compliance period. Some of these owners indicated that in the event the allowance price cannot be justified, plants will curtail output. Those plants with cycling capabilities anticipate that their dispatch factor will be reduced by "a few percent." None of the generators contacted believe that an investment in gas-firing capability to comply with RGGI can be justified at this time.

- Regulated versus unregulated generation - Firms with New Hampshire generation assets have greater flexibility and less risk with respect to investments in renewable projects that create offsets or early reduction credits. For example, PSNH has already applied to the NHPUC to convert Schiller Unit 5 from coal to wood and recover all prudently incurred costs associated with the cost of conversion under its existing Stranded Cost Recovery Charge. In contrast, unregulated firms will tend to rely on aggregators or brokers to obtain offset allowances. This is currently a developing market; offset projects meeting all the additionality tests may find it difficult to attract capital. One respondent reported that the firm has been unable to find any qualified offset projects.

- Fossil plant capacity relative to entire portfolio – Firms with a relatively small amount of fossil-fuel capacity in their generation portfolio will have a relatively small exposure to allowance price risk. These firms are more likely to cover their emissions with allowances and/or a risk management product. Cash losses, if any, may be offset by the enhanced value of their non-emitting capacity resources under RGGI.

- Pumped storage – These facilities will indirectly be burdened with the cost of CO_2 allowances associated with off-peak energy. Pumped storage could become less economic as CO_2 allowance prices increase and the spread in operating costs between coal and gas-fired plants diminishes.

- Market sales versus off-take contract – Firms that sell most of their output through forward bilateral contracts for sales have expressed concern that their allowance costs would not be fully recoverable under those agreements. Depending on the terms of the off-take contract, these generators stated that they might curtail output if their emissions are uncovered. LAI is unable to evaluate these generators' claims that these variable costs would be unrecoverable. LAI does not know the provisions or remaining terms of such agreements, which are confidential. Generally, most PPAs include change of law provisions that allow new environmental requirements to be equitably shared. Nonetheless, it is reasonable to expect that some plants under bilateral agreements will reduce their capacity factor to manage this risk.

- Firms with regulated gas LDC affiliates – A small number of RGGI-affected firms operate both generation and gas distribution companies. These firms have the unique ability to create offsets by converting affiliates' customers from oil to gas. LAI has been told that offset allowances resulting from these conversions can be transferred from the LDCs to the gencos, with appropriate accounting treatment.

- Cumulative regulatory impact – Several generators indicated that accelerated plant retirements may occur among older facilities that are currently on the cusp of financial health. New federal caps for NO_x, SO_2, and mercury under the Clean Air Interstate Rule and the Clean Air Mercury Rule, the new federal Section 316(b) requirements for cooling water intakes, and stricter mercury limits in Connecticut and Massachusetts all have compliance dates between now and 2010. Generation owners commented that, while it would be misleading to attribute potential retirements to RGGI alone, the cumulative impact of the multiple new environmental requirements are likely to take a toll on some marginal units.

Impact of RGGI on Resource Adequacy

RGGI is not intended to or expected to cause a seismic shift in the northeast power markets or the existing resource mix. LAI anticipates, however, that the major program unknowns – how allowances will be allocated within each state program, whether RGGI will stimulate a vigorous offsets market, how a new-source set-aside will be structured, and how leakage will be managed – *will chill or stall near-term investment in new generation projects*. The state programs are unlikely to be finalized for another one or two years. The ICF RGGI model, which reassured the Staff Working Group that the economic and reliability impacts of RGGI would be manageable, assumed that the earliest on-line date for a new combined cycle plant would be 2008. In our opinion, certain of ICF's key assumptions appear optimistic, especially in light of the fact that

FERC has not yet approved the FCM settlement[7] and capacity rates during the transitional period through 2010 are materially lower than the cost of new entry. Moreover, fundamental uncertainties about the region's natural gas supply and the timing of new LNG import terminals in the Maritimes and/or New England tend to slow down combined cycle plant development until the value of installed capacity (ICAP) across New England is revitalized – probably no earlier than 2010. Excluding wind and the 345kV transmission improvements in Connecticut, the lack of discernible project development across New England suggests that the next combined cycle plant in New England will not be commercialized until the FCM is implemented in 2010 or 2011. At this time, the potential for adverse interaction effects between the proposed FCM framework and RGGI is not adequately understood.

During development of the Draft Model Rule, the Staff Working Group and Stakeholders held extensive debate on whether allowance prices should be capped. Under Massachusetts 7.29 rules, allowances are effectively capped at $10/ton, and generators would pay a deficiency charge of $10/ton into a carbon trust fund if allowances were not available below that price. However, under RGGI, the $10/ton upper safety valve trigger may be exceeded. If this occurs, the use of offsets expands, which is intended to mitigate price run-ups during scarcity conditions, but not cap prices.

The Draft Model Rule contemplates a robust market trading the 4 million offsets initially allowed under the program across the RGGI states (approximately 874,000 offsets usable in New England). Some brokers and aggregators have expressed interest in this nascent offset market. However, many stakeholders believe that projects that create CO_2 allowance offsets are unlikely to attract capital based on the offset revenues alone. Cash flows from offset revenues bear considerable risk: (1) offsets are granted for only 10 years, with a potential to renew for another 10 years; (2) offset values can change significantly from year to year depending on whether a trigger event or a reset occurs. Furthermore, projects that qualify for RGGI offsets must meet the "additionality" test. They must be projects that would not otherwise be undertaken *but for* RGGI. The "financial additionality" test may therefore be a difficult standard to meet. Many stakeholders contacted in this study expressed concern that sufficient qualified offsets would not be created to mitigate allowance price run-ups. At this juncture, it is not possible to judge whether stakeholders will tolerate sustained high allowance prices resulting from a scarcity of allowances and a shortage of qualified offsets. If such conditions materially exacerbate issues of resource adequacy and fuel diversity, states may be prompted to adjust the rules accordingly.

[7] LAI expects FERC to approve the FCM settlement in Q2 2006 in order for ISO-NE to implement the transitional payments in December 2006 and the FCM in Q2 2010.

Conclusions

Based on this informal survey of generators and other RGGI stakeholders, LAI draws the following conclusions about the potential implications of RGGI for ISO-NE:

- Generation owners have developed preliminary RGGI compliance strategies for their affected plants. Given the remaining program unknowns, these preliminary strategies will likely evolve until each state promulgates its own statutes and/or regulations to implement RGGI.

- Most generators intend to use their allocated allowances, buy allowances in the market, create early reduction allowances where possible, and use/create offsets if needed. They will use risk management tools to manage their compliance similar to what they currently do for SO_2 and NO_x emissions compliance.

- Some plants may curtail operation of their units if their allowance allocations are insufficient to cover operations and CO_2 allowance costs become too high. Generators with bilateral contracts may also curtail operation if they are not able to recover all of their CO_2 allowance costs during the contract period. These practices may affect reliability. Uplift costs may increase if generators who are dispatched out of merit order submit bids that reflect high allowance costs. The magnitude of these impacts has not been determined.

- RGGI compliance strategies will tend to increase reliance on natural gas. Because of the higher CO_2 cost adder for coal and oil relative to gas, coal and oil plants may operate a little less, while gas units, still being on the margin, will likely increase their operation by a few percent. Dual fuel plants will also rely more heavily on gas. Core gas consumption may also increase under RGGI if the LDCs convert customers from oil to gas to create offsets.

- With respect to plant retirements, units that are already in financial jeopardy may be dealt a final blow by the cumulative cost of several concurrent new environmental compliance requirements, including RGGI. Assigning RGGI as the total causal factor may not be appropriate; other federal and state regulations governing emissions and cooling water intakes will require significant investment and increased operating costs at many plants, some of which may already operate at low capacity factors.

- Offsets within RGGI states may not be widely available to supplement any shortage of CO_2 allowances in the market. If the $10/ton upper price trigger is exceeded, then greenhouse gas reductions under the Kyoto Clean Development Mechanism might be available and qualified to substitute for offsets derived within the RGGI states.

- Given the uncertainties already affecting the New England capacity market, RGGI adds another uncertainty that, in combination, may chill or even stall near-term investment in new generator capacity.

- Finally, the RGGI Staff Working Group modeling was performed to evaluate the impact of a regional CO_2 cap using assumptions that seem optimistic with respect to energy efficiency expectations, new capacity buildout, availability of new infrastructure to support new gas capacity, and achieving states' RPS goals. More realistic considerations regarding the feasibility of siting new generation and expanding fuel infrastructure may affect the ability to meet the RGGI cap.

Attachment 1

Table 2 provides the CO_2 emission rates per unit of electric power for generic new capacity resources. In general, coal combustion emits about twice the CO_2 compared to natural gas per unit of generation, even for new technologies.

Table 2 – Characteristics of Potential New Generators in New England

	NG CC	NG CT	Coal ST	IGCC
Technology Type	Combined Cycle	Combustion Turbine	Pulverized Coal	Integrated Gas Combined-Cycle
Fuel Type	Natural Gas	Natural Gas	Coal	Coal
CO_2 Content *(lbs./MMBtu)*	117	117	205	205
Heat Rate (HHV) *(Btu/kWh)*	6,700	9,000	8,600	8,300
CO_2 Emissions Rate *(tons/MWh)*	0.39	0.53	0.91	0.88

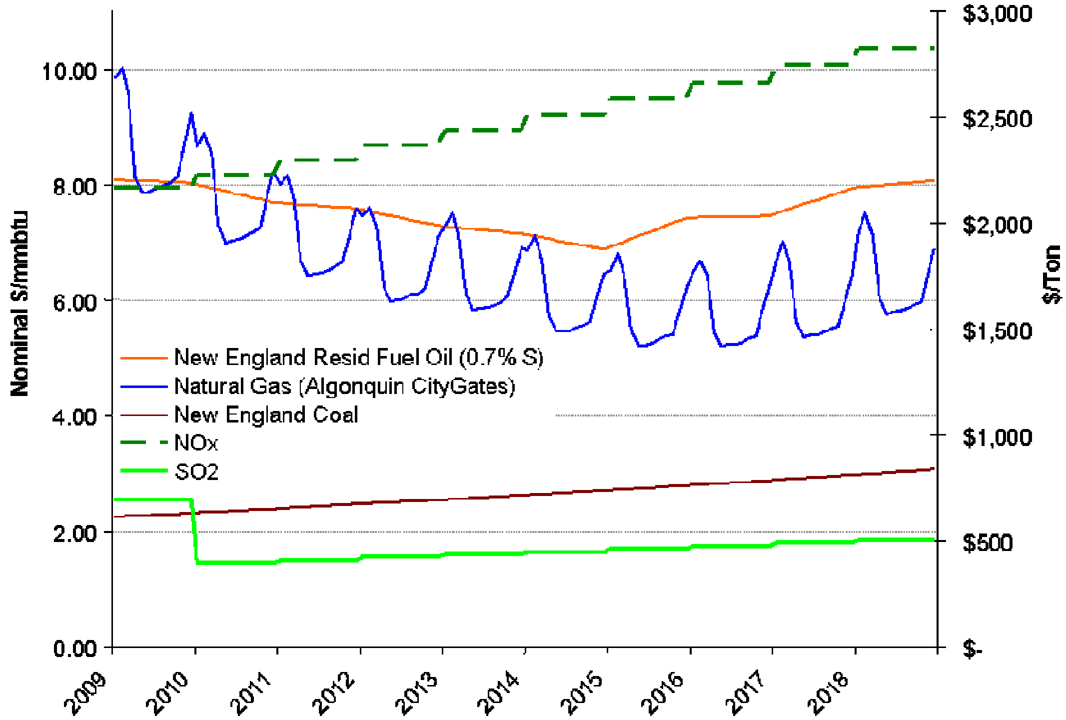
As for existing units, economics of coal-fired generation will be adversely affected relative to other types of generation. Table 3 shows the characteristics of generic incumbent generators in ISO-NE.

Table 3 – Typical Characteristics of Existing Generator Types in New England

	NG CC	RFO ST	Coal ST
Technology Type	Combined Cycle	Steam Turbine	Steam Turbine
Fuel Type	Natural Gas	Resid Oil 0.7% S	Coal
CO_2 Content *(lbs./MMBtu)*	117	160	205
Heat Rate (HHV) *(Btu/kWh)*	7,700	12,000	11,000
CO_2 Emissions Rate *(tons/MWh)*	0.45	0.96	1.13

To relate allowance prices to fuel costs, LAI utilized a fuel price forecast developed in Q1 2006. Figure 1 displays the fuel and emissions price forecast used in this analysis. The SO_2 and NO_x allowance price forecasts are based on reported futures prices through 2010 and 2008, respectively.[8] Beyond the futures data, allowance prices are assumed to escalate at inflation.

Figure 1 – Fuel and Emissions Price Forecast

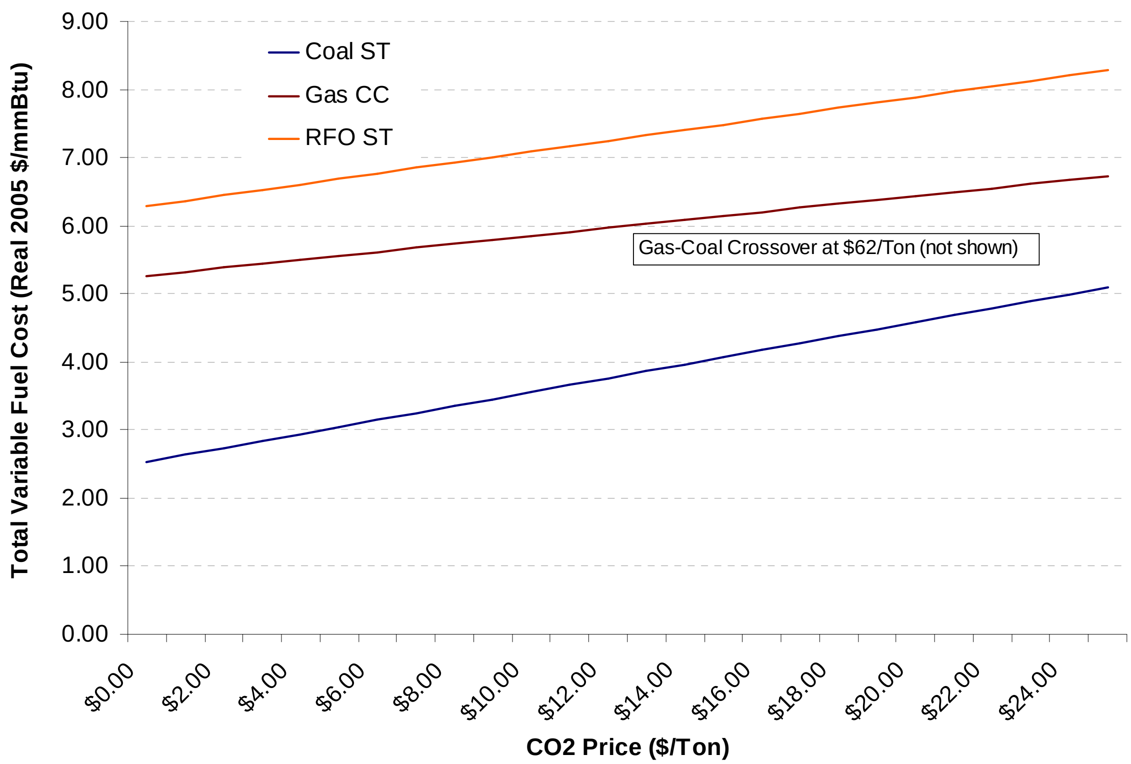


[8] Futures prices reported by Evolution Markets, LLC March 28, 2006 (www.evomarkets.com). Until 2003, SO_2 allowance prices remained stable in a relatively narrow bandwidth of $150-$200/ton. In anticipation of the Clean Air Interstate Rule (CAIR), SO_2 allowance prices soared to over $700/ton beginning in January 2004 Following promulgation of CAIR, SO_2 allowance prices again jumped beginning in October 2005 reflecting upswings in oil and natural gas prices, reaching an all-time high of $1630/ton on December 9, 2005. Since then, SO_2 allowance prices have been declining, but still remain significantly higher than historic levels.

Existing New England Generators

Figure 2 illustrates the average variable fuel cost at varying CO_2 allowance prices for different fossil fuels delivered to New England, applying emission rates typical of existing generators. In this analysis, "total variable fuel costs" include the delivered fuel price plus CO_2, NO_x and SO_2 allowance price adders. Note that natural gas and coal costs converge as the CO_2 allowance price increases. However, it would require CO_2 allowance prices in excess of $60/ton before these total variable fuel costs associated with coal exceed the same variable costs associated with natural gas.

Figure 2 – Total Variable Fuel Costs vs. CO_2 Allowance Price (Existing Generators)



As a percentage of total variable fuel costs, however, the CO_2 allowance cost for coal is material, even at the prices forecasted by the Staff Working Group of less than $6.50/ton (Figure 3).

Figure 3 – CO_2 Allowance Cost as a % of Total Variable Fuel Costs (Existing Generators)

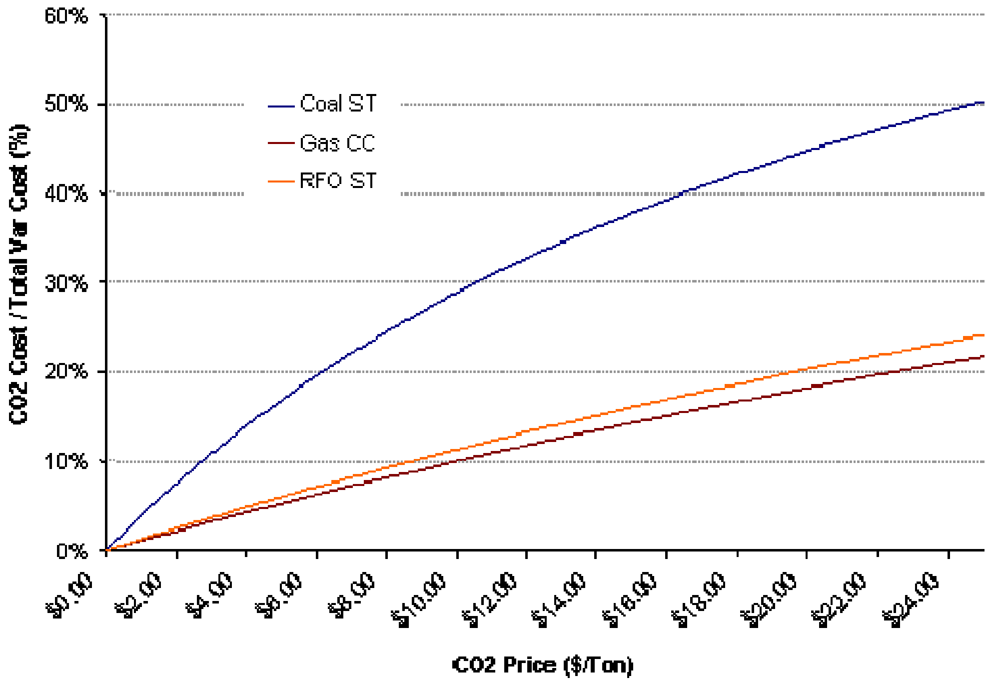
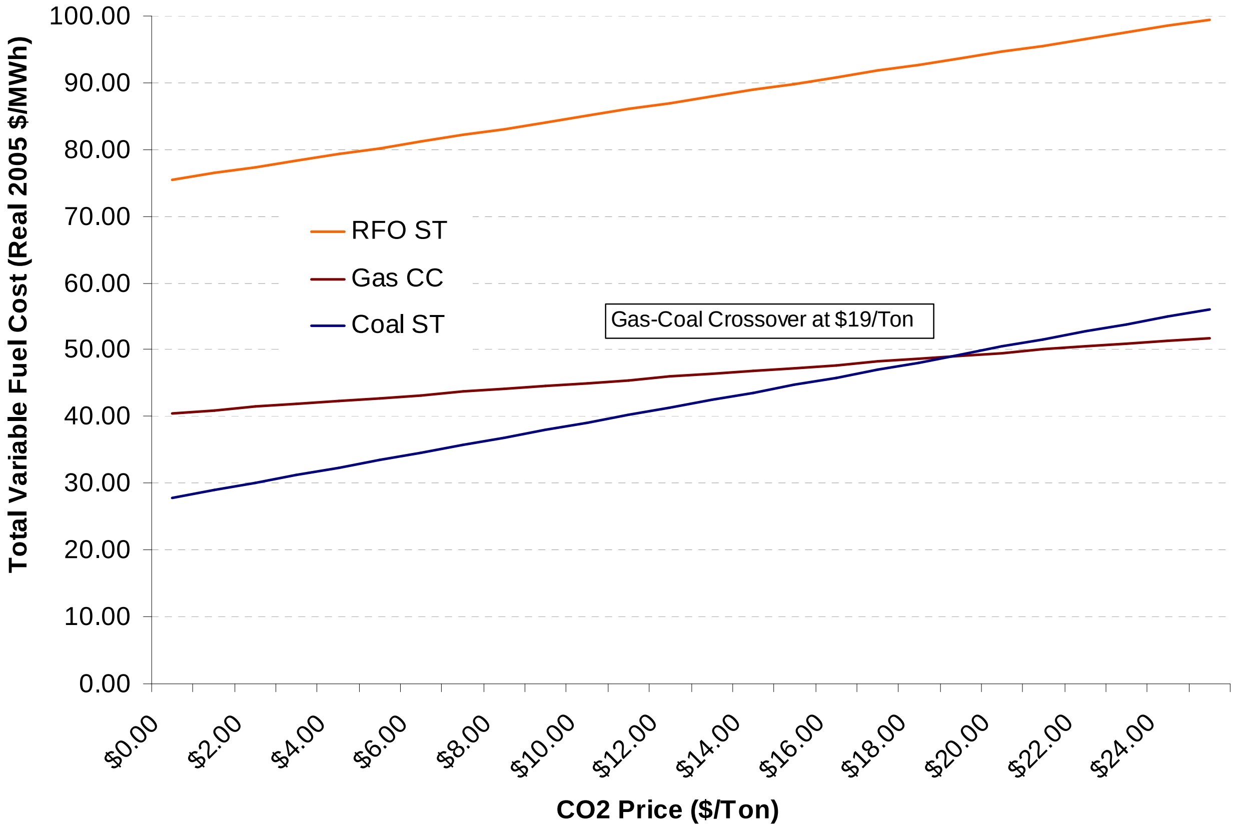


Figure 4 shows the average total variable fuel cost contribution to electricity production, on an output basis, using the heat rates presented in Table 3 for three typical power generation technologies. Because of its superior heat rate, the variable fuel cost of a combined cycle gas plant becomes *lower* than that for a coal steam turbine when CO_2 prices exceed roughly $19/ton. (Note that this chart represents *typical* units and the crossover point should be considered approximate only.) At allowance or offset prices less than about $19/ton, there may be some coal-fired units that can still no longer compete and would weigh retirement against capital expenditure for alternative compliance strategies.

Figure 4 – Total Variable Fuel Costs Contribution to Energy Price (Existing Generators)



New England Potential New Entry

Figure 5 shows the average total variable fuel cost at varying CO_2 allowance prices for potential new entrants in New England. For new entry, coal and gas costs equalize at over $70/ton.

Figure 5 – Total Variable Fuel Cost vs. CO_2 Allowance Price (Potential New Entry)

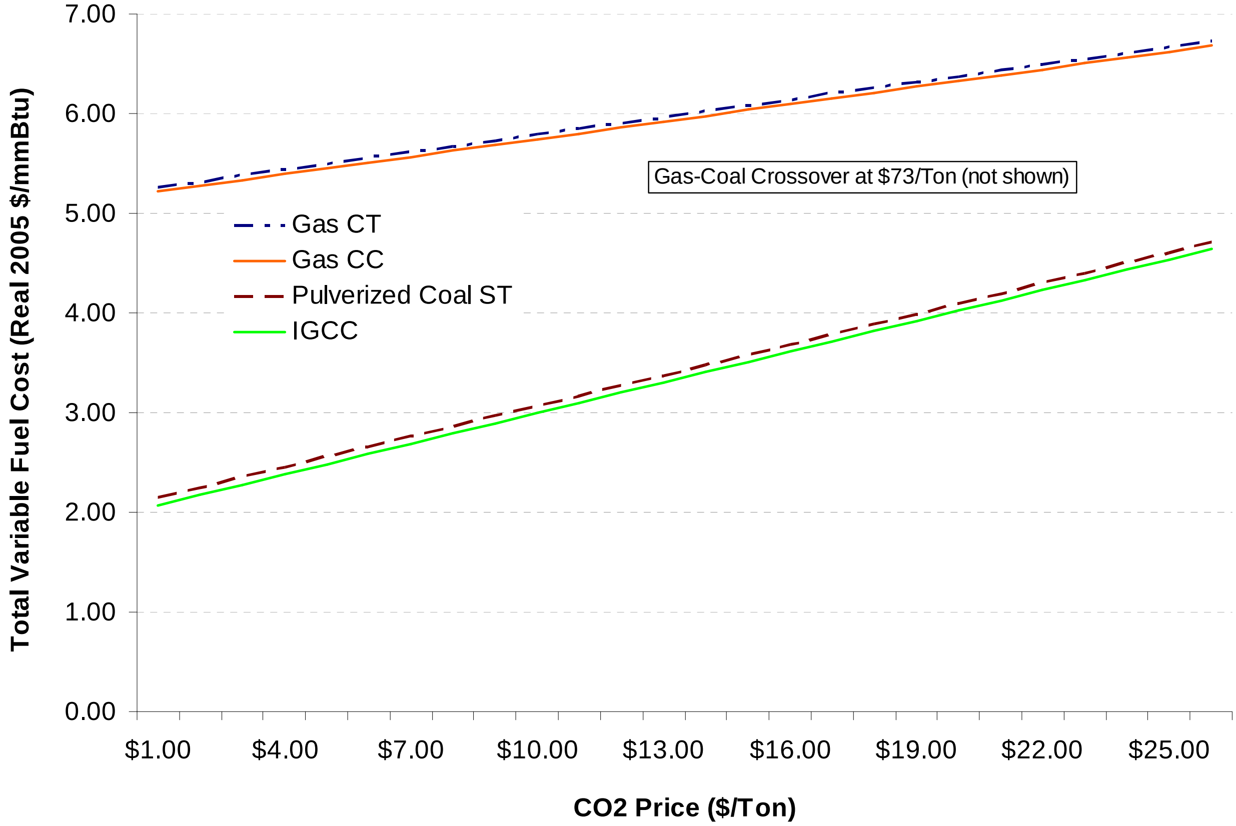


Figure 6 shows the CO_2 allowance cost as a percentage of total variable fuel cost:

Figure 6 – CO_2 Allowance Cost as a % of Total Variable Fuel Cost (Potential New Generators)

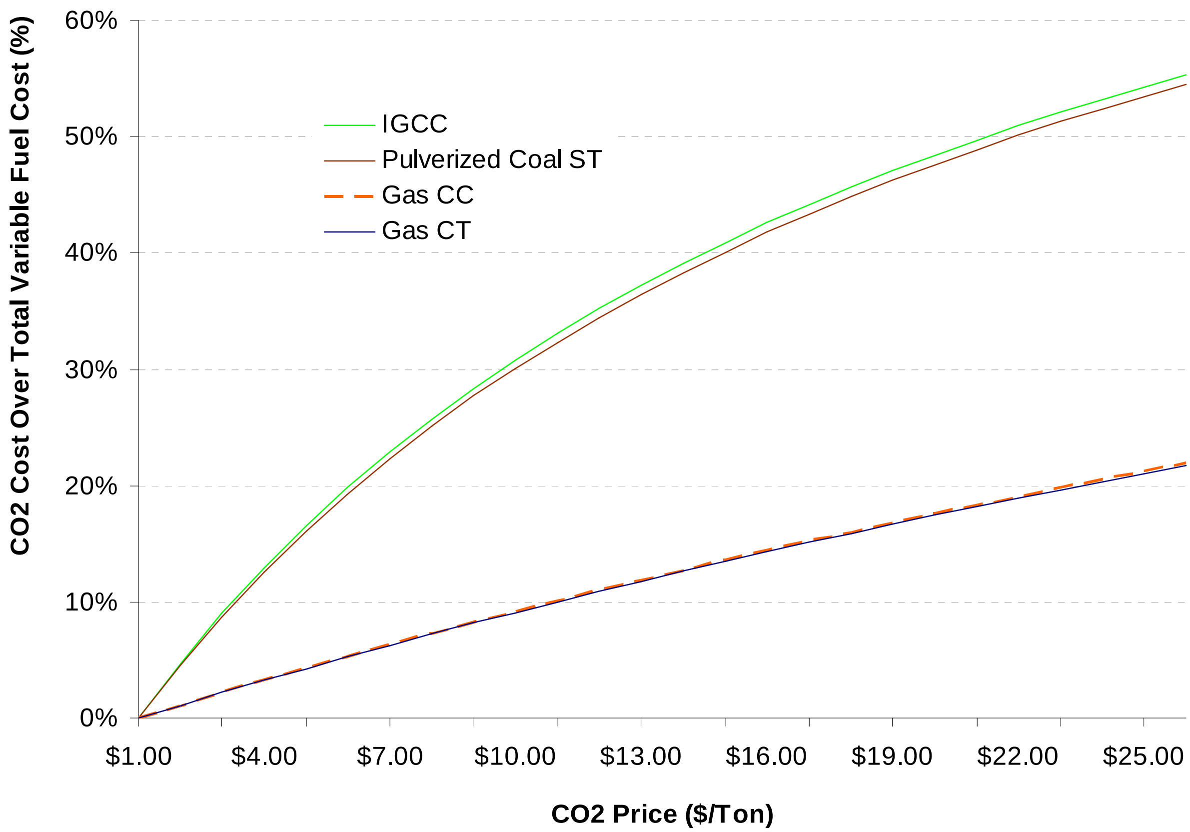
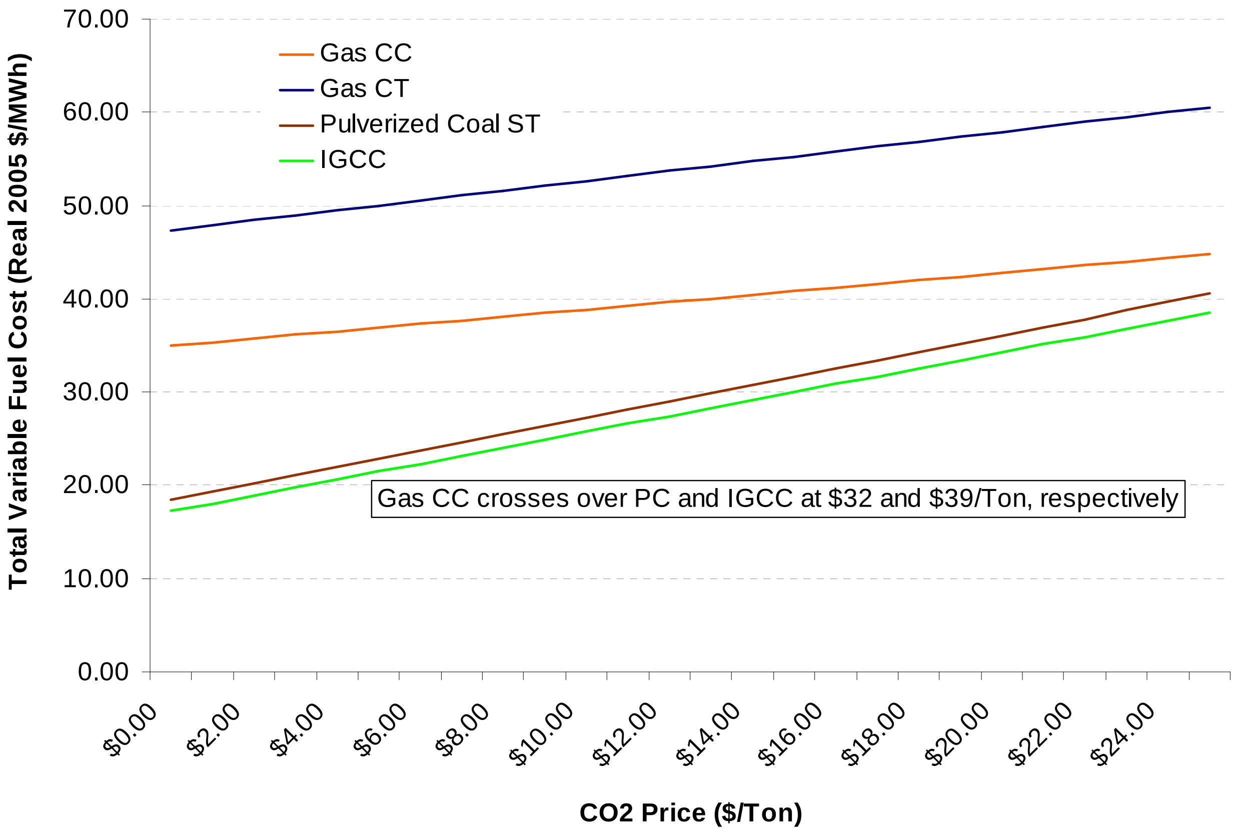


Figure 7 shows the average total variable fuel cost contribution to electricity production, using the heat rates presented in Table 2 for four generic new entrants. Because of its superior heat rate, the variable fuel cost for a gas combined cycle plant becomes lower than that for a new coal pulverized coal steam turbine when CO_2 allowance prices exceed $33/ton, and becomes lower than that for a IGCC unit when CO_2 allowance prices exceed $39/ton.

Figure 7 – Total Variable Fuel Cost Contribution to Energy Price (Potential New Entry)



Attachment 2

On behalf of the Staff Working Group, ICF Consulting applied the Integrated Planning Model (IPM) to forecast electric market conditions under various scenarios.[9] The impact of RGGI was analyzed by comparing a Reference Case – an outlook of the Northeast's electric market without a CO_2 cap – with a range of scenarios in which RGGI is implemented. The model incorporated various assumptions regarding fuel prices, electric demand, expected transmission infrastructure changes, and legislative restrictions. Market parameters resulting from the model included plant dispatch, power and allowance prices, new plant entry and retirement, and natural gas demand over the forecast horizon. Modeling was largely completed prior to the execution of the MOU and most runs are based on nine RGGI states participating. Eight-state RGGI runs were done as sensitivities only. LAI notes that the model runs incorporated a number of very optimistic assumptions regarding implementation of states' RPS and the effectiveness of energy efficiency programs:

- The Reference Case assumed that the RPS programs currently promulgated in the RGGI states will function fully as designed, *i.e.*, the targeted percentage of renewable resources will be sited, financed, and begin commercial operation on schedule. A Reference Case sensitivity tested a scenario in which only 50% of the planned RPS resources are built and become operational. This case is referred to as "Reference + 50% RPS" in the figures below. A comparable scenario to test the RGGI package with only 50% of RPS resources was not modeled by the Staff Working Group.

- The Reference Case did not assume any end-use efficiency gains, but almost all the other scenarios assumed that existing public benefit end-use efficiency programs will be funded at their current levels through 2024 and will achieve gains based upon current payback rates. These cases are all labeled with "1x Efficiency." The Staff Working Group also tested a Reference Case scenario that doubled the end-use efficiency programs and a Reference Case scenario where all end use efficiency programs are implemented (roughly equating to a tripling of the existing programs), but those results are not shown here. The 1x and 2x demand-side programs ramp up from no load reduction in 2006 to reductions of 5% and 10%, respectively, in 2024.

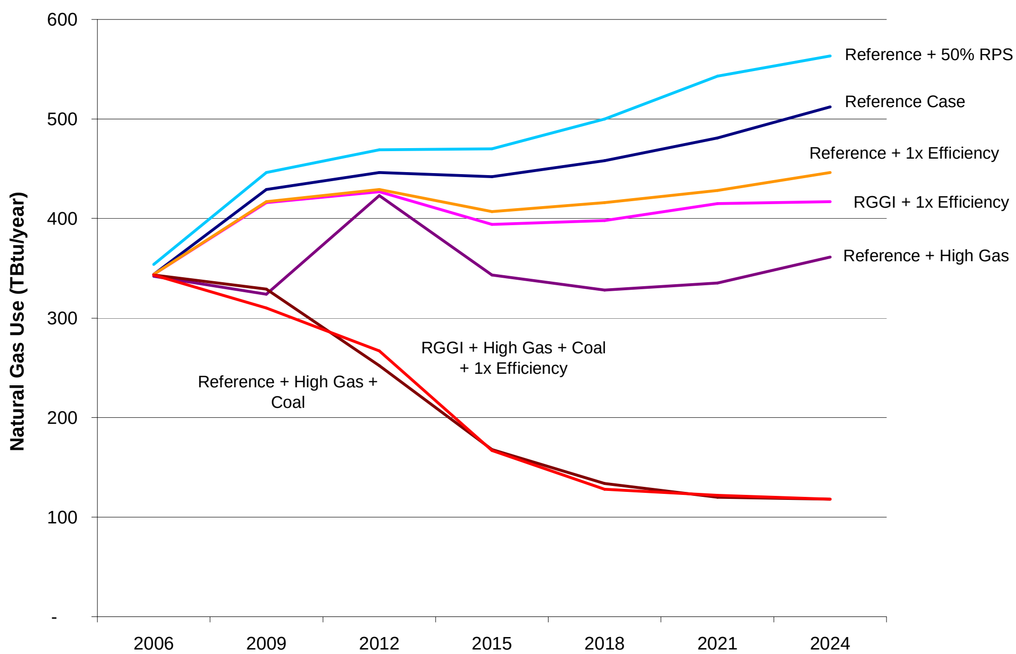
- Most modeling scenarios suppressed any new coal plants in ISO-NE and the rest of the RGGI states. However, new coal projects were allowed in two of the high gas scenarios. In these two scenarios, almost all new fossil generation to meet load is coal-fired, supplanting new gas combined cycle plants in other scenarios. Note that, in the two coal scenarios, the RGGI case is coupled with 1x Efficiency improvements while the Reference Case is not.

[9] IPM is ICF's proprietary linear dispatch electric market and grid operation model. Modeling assumptions were developed by the RGGI Staff Working Group and are discussed in the 2/10/2005 Modeling Assumptions document available at http://rggi.org/documents.htm

The natural gas use forecasts for generation in ISO-NE under the various scenarios are shown in Figure 8. A number of features are notable. The highest gas use emerges under the "Reference + 50% RPS" scenario, which assumed that gas prices ease to $4.80/MMBtu (2003$) across the forecast period, RGGI is not enacted, and only 50% of the planned RPS resources are commercialized. In this scenario, gas consumption for electric generation grows to 563 TBtu/year in 2024. For reference, EIA reports that 368 TBtu of natural gas was used for electric generation in New England in 2005. The ability of New England's natural gas supply infrastructure to handle this growth would require separate study.

Relative to the Reference Case, the 1x Efficiency and the High Gas scenarios result in slower growth in gas demand. Under the two coal scenarios, gas demand diminishes over the forecast period as gas-fired generation is displaced by lower cost coal-generation.

Figure 8 – Natural Gas Used for Generation in ISO-NE



LAI examined generation by resource type to interpret the difference in gas demand between the "Reference + 1x Efficiency" scenario to the "RGGI + 1x Efficiency" scenario. The projected impact of the RGGI Model Rule is a reduction in gas-fired generation and a comparable increase in transmission imports (leakage). Figure 9 illustrates the expected change in generation by resource type attributable to RGGI, calculated as the annual generation for the "RGGI + 1x Efficiency" scenario minus the annual generation for the "Reference Case + 1x Efficiency" scenario. Reductions in gas-fired and coal-fired generation are offset by increases in net transmission imports and a slight increase in on-shore wind generation. All other resource types had net change in generation of less than 300 GWh/year in 2024 and are not shown on this chart.

Figure 9 – Change in Generation by Resource with RGGI Program vs. Reference Case

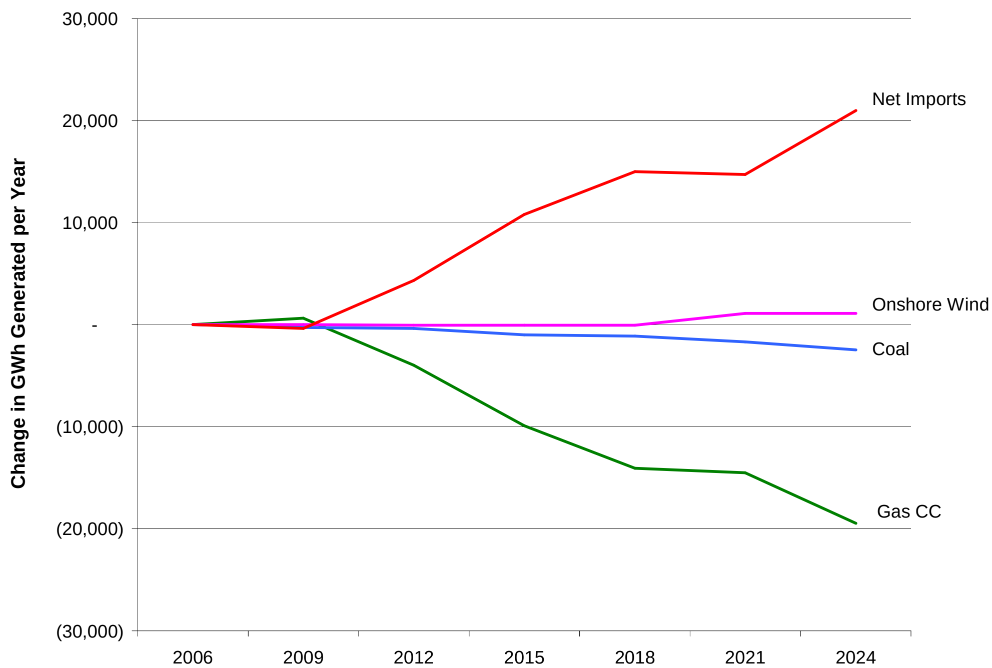
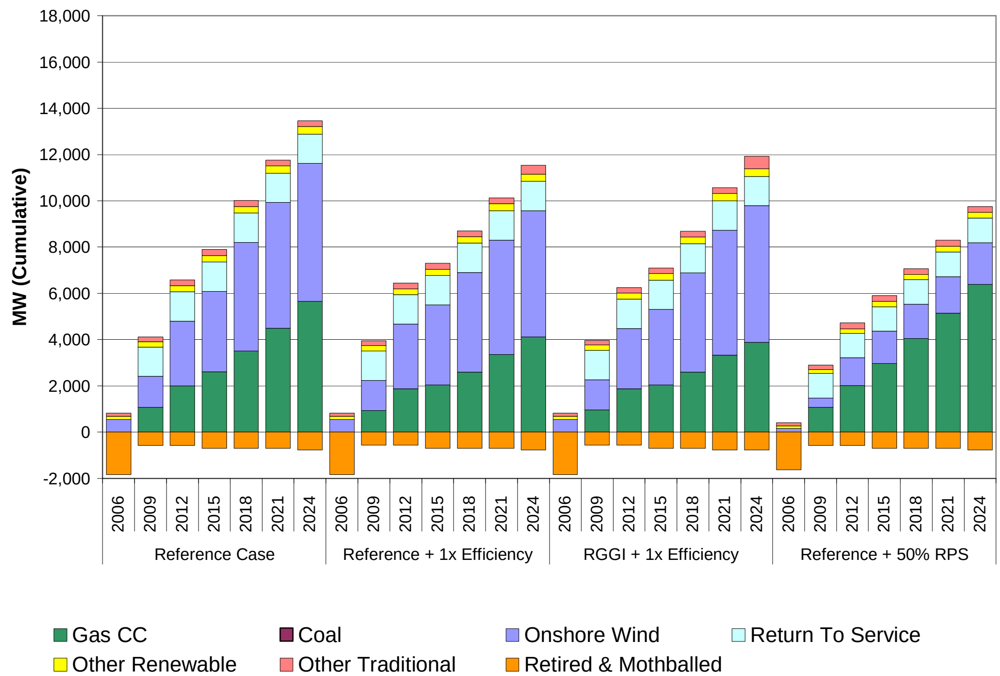


Figure 10 and Figure 11 illustrate cumulative capacity additions and retirements in ISO-NE under each of the model scenarios outlined above. Capacity additions are grouped by resource type. "Other Traditional" primarily consists of nuclear uprates, but also includes coal repowering to supercritical and new gas combustion turbines. "Other Renewable" primarily consists of hydroelectric and landfill gas resources, but also includes biomass and fuel cell capacity. "Retired & Mothballed" is chiefly oil/gas capacity mothballed in 2006 that reappears under "Return to Service" in 2009, with a minor amount of retired oil/gas and coal in other years.

The projected resource mix over the forecast period reflects two of the Staff Working Group assumptions: (1) the states' RPS programs will stimulate investment in new renewable capacity, and (2) energy efficiency programs will significantly reduce the need for new capacity over the forecast period. The four scenarios shown in Figure 10 all utilize the base gas price forecast, which stabilizes at $4.80/MMBtu (2003$), and suppress the addition of new coal capacity. In these cases, the resource mix projections show a heavy reliance on on-shore wind and gas combined cycle to meet load growth over the forecast period. Under the RGGI program, the CO_2 cap is principally met through efficiency and decreased reliance on new gas capacity. Relative to the Reference Case, efficiency programs reduce incremental gas capacity by 1,539 MW by 2024, while RGGI further reduces incremental gas capacity by 237 MW.

Figure 10 – Cumulative Changes in Capacity in ISO-NE, Base Gas Price Scenarios



In the two High Gas scenarios that include new coal capacity in the resource mix, coal displaces new gas combined cycle, but on-shore wind still provides the largest contribution to new capacity. Figure 11 compares the Reference Case (using the base gas price scenario) with the three high gas price scenarios, which assume gas prices average $7/MMBtu (2003$) over the forecast period. Coal completely replaces new gas capacity, but does not result in significant retirement of existing gas-fired capacity. With high gas prices, much more wind capacity than mandated by RPS is constructed. (The model does not consider siting limitations for wind projects.) The "RGGI + High Gas + Coal + 1x Efficiency" case has significantly less incremental capacity because of increased transmission imports and because projected efficiency improvements reduce demand.

Figure 11 – Cumulative Changes in Capacity in ISO-NE, High Gas Price Scenarios