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The Impact of Long-Term Generation Contracts on Valuation of Electricity Generating Assets under the Regional Greenhouse Gas Initiative

Nathan Wilson, Karen L. Palmer, and Dallas Burtraw

1616 P St. NW
Washington, DC 20036
202-328-5000 www.rff.org

RESOURCES FOR THE FUTURE

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Abstract

The Regional Greenhouse Gas Initiative is an effort by nine states to constrain carbon dioxide emissions from the electric power sector using a cap-and-trade program. This paper assesses the importance of long-term electricity contracts under the program. We find that 12.2% of generation will be accounted for by long-term contracts in 2010, affecting select nuclear, hydroelectric, and cogeneration units. The contracts will have a negligible effect on the wholesale marginal cost of electricity and a small effect on retail price. States may want to consider contracts on a case-by-case basis when making decisions about the initial distribution of emission allowances, but they should account for effects on the portfolio of plants owned at the firm level, not the effects on individual facilities. Because of their relatively small effect, it seems unnecessary to allow the existence of long-term contracts to dictate the design of the overall program.

Key Words: climate, state policy, Regional Greenhouse Gas Initiative, long-term contracts, electricity

JEL Classification Numbers: Q54, Q58, L14, L94

Discussion papers are research materials circulated by their authors for purposes of information and discussion. They have not necessarily undergone formal peer review.

Contents

The Effect of Long-Term Generation Contracts on Valuation of Electricity Generating Assets under the Regional Greenhouse Gas Initiative

Nathan Wilson, Karen Palmer and Dallas Burtraw[*]

1. Introduction

The Regional Greenhouse Gas Initiative (RGGI) is an effort by nine northeastern and Mid-Atlantic states to reduce greenhouse gas emissions.[1] The program initially will constrain carbon dioxide (CO_2) emissions from the electric power sector using a mandatory cap-and-trade program. An investigation and deliberative process involving staff and stakeholders from the participating states is expected to culminate in 2005 in a memorandum of understanding and model rule that would be implemented by the states' governors beginning later this decade. Ultimately, the program could be expanded to address other sources of CO_2 and other greenhouse gases. If successful, it could become a model for a more comprehensive, national cap-and-trade program for greenhouse gases.

The implementation of RGGI could affect profoundly the market value of electricity generation assets in the region and in neighboring regions. For instance, a coal-fired power plant with a relatively high CO_2 emission rate could face substantial new costs relative to other facilities. Consequently, it may experience a reduction in utilization that would affect its market value negatively. If generation prices are set competitively, as they are in most RGGI states, then the market price of electricity will rise to the extent that emitting sources determine marginal generation cost and the retail electricity price. This price increase partially will counterbalance the higher costs faced by coal plants. However, nonemitting and low-emitting electricity generators, including nuclear units and many types of renewables as well as relatively efficient natural gas units, will experience little increase in cost but will be able to capture increased revenues. Nonemitting and low-emitting sources can also expect higher utilization given their lower costs. These changes could lead to significant increases in their market values.

One of the most important factors that affect the value of individual facilities is the method through which CO_2 emission allowances are allocated initially. Burtraw, Palmer, and Kahn (2005) examine three basic methods of initially distributing emission allowances: based on historic measures, updating measures of performance, or through an auction. The authors show that the way that allowances are distributed significantly affects the increase in electricity price and the ability of generators to pass on costs to

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[1] The nine states are: Maine, New Hampshire, Vermont, Connecticut, Rhode Island, Massachusetts, New York, New Jersey, and Delaware.

consumers, which ultimately determines the effect of the program on the asset values of generators.

The study by Burtraw, Palmer, and Kahn is built on a model of efficient electricity markets to determine wholesale electricity prices. In practice, however, electricity markets may not behave as characterized in the study. One primary reason is the existence of long-term contracts between electricity generators and distribution companies that may prohibit electricity prices from adjusting to accommodate the cost of compliance with the RGGI policy as predicted by the model. In that case, the predictions in the study about changes in electricity prices and the effect on consumers and producers of a greenhouse gas policy will be incorrect. If long-term contracts constrain the change in wholesale electricity prices, then the price effect of the policy will be less than forecast in the study. While this result is relevant to the industry in general, it is especially important to those individual facilities affected by these contracts, especially those that also face an increase in costs because of their emissions of CO_2. In some cases, owners of facilities may face an unexpected increase in costs due to the RGGI policy and they may not be able to offset that cost through an increase in electricity price.

This paper assesses the importance of long-term contracts to the determination of electricity price and to the calculation of the change in the market value of electricity generation assets as reported in Burtraw, Palmer, and Kahn. We provide information based on a survey of all the states involved in the RGGI process. Given the limited resources available for this inquiry and the proprietary nature of some contracts, we do not provide a comprehensive accounting of contracts. Instead, we develop an upper-bound estimate of the amount of electricity generation that is under long-term contract based on interviews with state public utility commission (PUC) staff as well as other interested parties in each state. We characterize this generation by the type of generation technology and fuel. On this basis, we assess the importance of long-term contracts to the forecasts provided in the previous study.

The next section of this paper outlines the way that long-term contracts can affect electricity price and the change in revenue that will be received by individual facilities. Subsequently, we provide the results of our survey organized into six categories of potential contracts: special nuclear arrangements; public hydropower; non-utility contracts made according to the Public Utility Regulatory Policies Act of 1978 (PURPA); contracts for generation that resulted from the restructuring of the electricity sector; tolling contracts; and miscellaneous types of contracts. We conclude with an assessment of the role of long-term contracts and how policymakers should consider the long-term contract issue when deciding which allocation scheme to pursue.

In brief, we find that long-term contracts for electricity generation are not widespread in the RGGI region. The results of our survey suggest that for the entire region no more than 13.8% of total generation in 2003 will still be under fixed price contract in 2010 and probably somewhat less. Three quarters of this generation is in New York State. If there is an increase in total generation from 2003 to 2010, the percentage will shrink accordingly. For example, if electricity demand increases 13.4%, as suggested by growth rates estimated in the *Annual Energy Outlook 2005*, then only 12.2% of total generation will be accounted for by long-term contracts (Energy Information Administration 2005).

We find that long-term contracts will have a negligible effect or no effect at all on the wholesale marginal cost of electricity. Most customers face a retail electricity price that is a weighted average of power purchased at the wholesale marginal cost and power purchased at contract prices. Hence, the increase in the retail electricity price is likely to be slightly less (roughly 13% less) than what is forecast by recent studies (Burtraw, Palmer, and Kahn, 2005, and other modeling for the RGGI staff working group). Accordingly, the increase in revenue going to the industry as a result of higher prices, which serves to partially offset the increase in costs, is overestimated because generation facilities under long-term contract will not benefit from the increase in the wholesale marginal cost due to the RGGI policy. The vast majority of the facilities under long-term contracts are select nuclear units, hydroelectric units, and cogeneration units operating under PURPA contracts. Because of their relatively small effect, it seems unnecessary to allow the existence of long-term contracts to dictate the design of the overall allocation scheme. Since these contracts may have significant effects on the individual plants involved, however, states may want to consider their status on a case-by-case basis when making decisions about the initial distribution of emission allowances. Some generation facilities will gain value and some will lose value under the RGGI policy. It is the portfolio of plants owned at the firm level that should be considered in making adjustments to allocation for the purpose of compensation.

2. Long-term Contracts Affect Electricity Price and Asset Value

As stated above, in a competitive electricity market the implementation of a cap on CO_2 emissions could lead to higher wholesale electricity prices as generators pass through the costs of constraining their emissions. Long-term contracts that force individual generators to forego this higher price and continue to provide power at the pre-RGGI price level could have a significant effect on the market value of these generation assets.

To illustrate the effect of a long-term contract on electricity price, consider the determination of electricity price in regions of the country with market-based prices, which characterizes the RGGI region. Except for those few, mostly industrial customers who have time-of-day or real time prices, electricity price is a weighted average of the real time marginal cost. Let us denote the real time marginal cost ($/MWh) in time block t by C_t and let g_t represent generation (MWh) in this time block. Denote total generation over time period $T=\{t\}$ as G_T. Then in the absence of fixed price contracts, the electricity price for the average customer for period T will be the average of marginal costs weighted by generation in each time period, or $\sum_t \frac{g_t}{G_T} C_t$. This is the representation of the competitive electricity price in competitive regions in the Burtraw, Palmer, and Kahn study if one ignores further distinctions in the model between generation price, reserve price, capacity payments, transmission and distribution costs, and customers facing real time prices.

If a share (s) of generation is delivered under fixed price contracts at marginal cost C^f there can be two effects on electricity price. One concerns the determination of the real time electricity price and the other concerns the electricity price faced by retail customers, which is an average of the real time electricity price and the contract price.

The determination of the real time electricity price is affected if the generation under fixed price contract would be the technology determining marginal cost in the absence of the contract. We find that this is seldom the case. Most of the generation under fixed price contract includes nuclear, hydroelectric, and renewables, which are not the marginal technology in most time blocks. Natural gas generation usually is the marginal technology and is rarely under long-term contract, with the exception of natural gas fired non-utility cogeneration facilities. In 2003, these facilities accounted for 34% of all natural gas generation, 63% of non-utility generation providing power to the electricity grid, that is, excluding industrial and commercial cogeneration, and about 9% of total generation. By 2010, when the program may take effect, we estimate that only about 20% of the generation under these contracts in 2003 will be under the original contract. The remainder of these contracts will have expired and/or have been renegotiated in light of the RGGI program. Moreover, cogeneration facilities often operate under other technological or contractual constraints that reduce their flexibility and the likelihood that they would ever determine the marginal cost of electricity generation in the market.

The second effect of fixed price contracts results because retail electricity price will be an average of that portion of power purchased at the competitive electricity price and that portion purchased at the fixed price. Where the implementation of RGGI raises the marginal cost of generation while some portion of wholesale electricity is purchased at a fixed price, those generators under a fixed price contract lose potential new revenue while their customers or other various stakeholders downstream gain as a consequence. Who is the winner among downstream stakeholders will depend on the specific rate plans in place for distributors. For example, if a distribution company's retail rates are still partially cost-based while wholesale costs increase, then retail consumers benefit from the presence of the long-term contract because the distribution company's costs do not increase. On the other hand, in some cases a distribution company obtains power from a generator under a fixed price contract but only a portion (x) of its sales to retail customers are at a fixed price and the utility charges the remaining portion ($1-x$) of its downstream retail customers the competitive electricity price, which is not affected by the fixed price contract.[2] Including this possibility, the average retail electricity price (P) for all customers is:

$$P = s\,x\,C^{f} + \left(1 - s\,x\right)\sum_{t}\frac{g_t}{G_T}C_t$$

[2] Despite the restructuring of electricity markets in all RGGI states, most of the electricity sold by distribution companies is sold under a fixed price arrangement, and thus in most RGGI states x is very close to 1 for residential customers. Using the percentage of load that is served by alternative providers as a proxy for (1-x) (Rose 2004) suggests that only New York has a substantial amount of switching to alternative providers among residential customers (roughly 5% of total residential load). Looking at all customers taken together, the share of total load served by alternative suppliers ranges between 38% (Maine) and 2% (Connecticut).

The difference between the retail price and the weighted average marginal cost may be negative or positive, depending on the terms of the fixed price contract, that is, whether C^f is greater than or less than the weighted average marginal cost term. However, if the effect of a RGGI policy is to raise costs for at least some generators, then the change (Δ) in the retail electricity price is strictly less than the change in cost: $\Delta P = (1 - sx)\Delta\left(\sum_t \frac{g_t}{G_T} C_t\right)$. Burtraw, Palmer, and Kahn account for the change in generation cost and in generation in each time block due to the increase in the electricity price and its effect on demand, but they do not account for the contribution of fixed price contracts. The actual change in electricity price due to the RGGI policy is likely to be smaller than Burtraw, Palmer, and Kahn forecast by approximately *s x*. One of the purposes of this paper is to assess the potential magnitude of the overestimate of the change in electricity price in that study.

Another important finding in Burtraw, Palmer, and Kahn is the effect on the market value of generation assets as a result of the RGGI policy. The authors use a discounted cash flow model to calculate market value as the net present value of future revenues minus future costs for the equilibrium solution. The most important source of future revenues in the model is the real time marginal cost of power (including the payment for reserve capacity). If the presence of fixed price contracts has virtually no effect on the real time marginal cost, as suggested above, then the main effect is that the change in aggregate revenues for the industry under the policy is based on the change in retail price, ΔP, rather than the change in marginal cost, $\Delta\left(\sum_t \frac{g_t}{G_T} C_t\right)$. The change in revenues for individual facilities also will differ; those facilities under contract will receive the contract price rather than the market price, and hence they will receive no increase in revenue. For these facilities, the authors' findings about the change in the value of generation assets will be overly optimistic. The second purpose of this paper is to assess the extent of this difference.

Finally, a central factor that determines whether long-term contracts deserve special consideration is timing. Many contracts may expire before the RGGI policy takes effect or before the policy ramps down the emission cap to a level that imposes important changes in the costs for the industry. These contracts do not seem to be important to the questions we are interested in. Second, contracts between privately owned facilities and distribution utility companies reflect expectations about future events. If these contracts were signed under the shadow of a potential carbon policy, then to some degree the negotiated price reflects the expected change in market conditions. To some degree, the fixed price contracts may already be adjusted to account for the change in costs of the RGGI program.

3. Survey Findings

We surveyed state officials to obtain a characterization of fixed price contracts and an indication of their effect on the change in electricity price and on the change in the value of generation assets. To the extent that it is possible, we identify the share of generation under contract in the aggregate and for specific technologies and the degree to which retail contracts reflect the fixed price wholesale contracts. We analyzed six types of contracts that we believed to be relevant.

3.1 Nuclear Contracts

The buyers and sellers of some nuclear facilities signed long-term contracts during the competitive restructuring process. These were designed to serve two purposes. First, the contracts guaranteed distribution utilities—the plants' former owners—a large amount of the base-load capacity and generation they required. Second, the new owners of the nuclear facilities were assured of a buyer for their power, ensuring that they would be able to achieve a return on their investment. Our survey of different state utility commissions suggests that contracts of long enough duration to still be in effect during the RGGI cap-and-trade program are not common; there appear to be only three in the RGGI region. Each contract is unique; even contracts signed for power from different reactors at the same facility are not analogous.

For example, at the Nine-Mile Point nuclear power plant in New York, the first reactor's power is contracted through 2009, when its operating license expires. The second reactor (9M2) has a 20-year contract that began in 2001. The generator receives a fixed price during the first 10 years of the deal, and a revenue sharing approach is taken for the second half of the contract. During this period, the price of power is allowed to fluctuate if it is within a given band. If the cost exceeds the upper bound, then the difference is split 80/20 between the purchaser and the generator. If price falls below the price floor in any month, then 80% of the difference is accounted for and credited against any potential future payments for months where prices exceed the upper bound. If there are negative balances at the end of the term, the investor-owned utility does not pay them to the generator—they are just ignored (money can flow only from the generator to the utilities purchasing power). The contract with 9M2 accounts for 90% of total output; the remaining 10% is not constrained by the contract and is sold at market price.

The R. E. Ginna nuclear facility in Rochester, NY, has a deal that is similar to the first 10 years of the 9M2 contract. Finalized in June 2004, the contract obliges the plant's buyer to provide 90% of the facilities' generation to Rochester Gas & Electric at a fixed price. The Vermont Yankee plant is the only other nuclear facility with a long-term contract in the RGGI region. Unlike the two New York facilities, it signed a 10-year contract promising 100% of its output to its former owner when it was sold in July 2002. Depending on market conditions, the price it received would fluctuate within a pre-established band.

None of the other nuclear plants in the region, including those in New York, has a contract longer than five years and none extend beyond 2004.[3] The PUC officials of other states in the RGGI region (and major observers) assert that the remainder of nuclear plants bid into the independent system operators-operated day-ahead markets like any

[3] Based on personal conversations and Nuclear Energy Institute (2005).

other base-load generators. This is true even in New Jersey, where nuclear power accounts for more than 50% of total generation.

Table 1 provides a list of all nuclear units in RGGI and an indication of its contract status or the date that the contract expires. The final two columns indicate the capacity of each nuclear unit and the general contract terms, including the amount of generation that is expected to be under contract in 2010, the year we assume RGGI will take effect.

Having gained an understanding of how much nuclear generation will remain under long-term contract after RGGI takes affect, we consider who benefits: the distribution companies that purchased the power or the consumers that ultimately will use it. As stated above, the answer to this question is dependent on the nature of the rate agreement negotiated by the local PUC and the distribution company. At present, rate arrangements in both New York and Vermont suggest that the bulk of the benefits accrue to consumers. In the notation introduced in the previous section, $x = 1$.

In New York, only 25% or so of most utilities' consumers chose rate plans other than the fixed, cost-of-service option. Since the rate plans that consumers' chose elapse in 2005, it is possible that competitive options will have a much larger share by the time RGGI is implemented. However, there have been no indications of broad consumer unhappiness and no suggestion that distributors will be able to stop offering a cost-based option. Therefore, we believe it more reasonable to assume that consumers will reap the benefits of the long-term nuclear contracts in New York.

Moreover, at present the New York Public Service Commission has structured electricity rates so that even those consumers who eventually choose to purchase their electricity from a competitive supplier would benefit from the existence of fixed price contracts. Broadly, the process works as follows. Consumers receive a credit for the difference between the market rate of generation and the long-term fixed price from their initial distribution utility. This credit is often referred to as a hedge. Though it nets out to the same effect, the credit is kept separate from the price (generally set at the average cost) of the commodity they are purchasing. If a given ratepayer switches to a competitive power supplier, they no longer have to pay the average cost of electricity provision, instead paying whatever the competitive supplier is charging. But the ratepayer retains the credit (some call this "taking the hedge with you when you go").

At the present time, there is even more limited access to competitive power providers in Vermont. Large industrial or commercial plants were given the right to contract with suppliers in 2004, but the Public Service Board has not moved away from its 2001 statement that the state's wholesale power markets were not sufficiently developed to allow retail competition for at least a few years (American Public Power Association 2005).

In conclusion, we find that the vast majority of power from nuclear plants will not be under fixed price contracts during the period that RGGI will be in effect, beginning approximately in 2010. Where there are fixed price contracts for power from nuclear plants in effect, we find that the vast majority of benefits would accrue to the ratepayer.

Table 1. Nuclear Plant Sales in the RGGI Region

Plant	State	Date Sold	Capacity (MW)	Contract Details
Pilgrim	MA	7/13/99	670	5-year contract at 3.5 to 4 cents/kWh
Oyster Creek	NJ	8/8/00	619	3-year contract at 3.4 cents/kWh
Vermont Yankee	VT	7/1/02	510	10-year contract at 3.9 to 4.5 cents/kWh with "low market adjuster"
Indian Point 3	NY	11/21/00	965	3.6 cents/kWh through 2004
Fitzpatrick	NY	11/21/00	778	3.2 cents/kWh for 46% of output and declining to 31% in 2004; 500,000 KW at 2.9 cent/kWh (balance of output)
Nine Mile 1	NY	11/7/01	613	Fixed price (dependent upon year) contract for 90% of output from date of sale through the end of license in August 2009
Nine Mile 2	NY	11/7/01	937	10-year fixed price contract, followed by 10-year revenue sharing agreement; 90% of output
Millstone Units	CT	3/31/01	2680 (before unit 1 shutdown down)	n/a
Indian Point 2	NY	9/6/01	975	3.9 cents/kWh through 2004
Seabrook	NH	11/1/02	1161	Unknown
Ginna	NY	6/10/04	495	90% of output sold for 10 years

Source: Nuclear Energy Institute 2005; discussions with PUC officials.

3.2 Public Power

New York is the only state in the RGGI region with long-term contracts for publicly owned hydroelectric power. The New York Power Authority (NYPA) operates two major facilities: the Niagara Falls and St. Lawrence River projects. In accordance with federal law, the plants provide very low cost power to municipal and rural electric cooperatives. The NYPA also sells some of its power at cost to government agencies, private companies, and private utilities for resale.[4] The principal reason that New York is the only state with long-term hydroelectric contracts is that there are no other large

[4] Information on NYPA can be found at its website: http://www.nypa.gov/about/whoweare.htm.

publicly owned dams in the Northeast. Most of the dams in the region were built prior to the 1940s. Table 2 contains a description of NYPA's two public hydroelectric facilities.

At present there is no indication that the current arrangement of selling public hydropower at or close to cost will change prior to 2010 or at any point thereafter. In other words, it is likely that NYPA will not receive the higher wholesale electricity prices expected to prevail after RGGI's enactment. The Niagara Falls and St. Lawrence River projects are publicly owned and exist to benefit consumers. As the current contracts were established to help consumers, the fact that consumers will benefit from them even more under RGGI does not pose a redistributive problem. Retail customers are likely to receive the overwhelming majority of the benefits since as we noted in 3.1, most of them continue to receive cost-of-service rate plans.

Table 2. Public Hydroelectric Contracts in RGGI

	State	Capacity (1999)	% Sold	Length of Contract	Generation (2003)	Expected Affected Generation in 2010
St. Lawrence Power Project	NY	912	100%	Perpetuity	6,129,198	6,129,198
Niagara Falls	NY	2625.9	100%	Perpetuity	12,066,078	12,066,078

Source: New York Power Authority, http://www.nypa.gov/facilities/default.htm; EIA, 906 and 920 historical databases, http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html.

3.3 PURPA Contracts

By far the most common form of long-term generation contract is with non-utility generators (NUGs). These contracts date largely from the 1980s under the rationale that allowing entrepreneurs to supply power to utilities could increase the efficiency of the generation sector, coupled with growing concern about the environmental consequences of traditional generation technologies. PURPA facilitated contracts with NUGs. Under PURPA, utilities were obliged to purchase power from qualifying facilities (QF) at a price equal to the cost they "avoided" having to pay to develop new facilities themselves. The QFs were mostly small combined heat and power (cogeneration or "co-gen") facilities or non-hydroelectric renewable plants (Borenstein and Bushnell 2000).

In retrospect, it is clear that many of the PURPA contracts were signed during a period of high electricity prices. By the late 1990s, the fixed prices paid for NUG power consistently were above current market prices. Because the contracts have proven uneconomic in this way, utilities in the RGGI region have been working with PUCs to buy their way out of the contracts. Where this has proven impossible, the utilities were able to incorporate the contracts into their stranded cost recovery process during restructuring. While the PURPA contracts are a widespread phenomenon, they vary widely in nature. Most are small in scale, but others, like the Panda Brandywine and

Warrior Run plants in Maryland (a state that has observer status in the RGGI process), are 180-megawatt projects.

Maine probably has both the most PURPA contracts and generation (relative to overall consumption) inside the RGGI region. At one time, the state had as many as 80 contracts with NUGs, a substantial proportion of which remain in effect. It should be noted, however, that the capacity of most of the plants is very small, perhaps even too small to be subject to RGGI caps. However, even if the plants have no compliance obligation, the asset values of these plants could be affected by changes in electricity price if they are not operating under fixed price contracts. Public utility commission officials from both Pennsylvania (another RGGI observer) and Massachusetts also acknowledge that their states still have a fair number of contracts with NUGs in force. Most of these in Massachusetts are due to expire in 2012, while those in Pennsylvania will remain a factor through 2020. Long-term contracts for the aforementioned projects in Maryland were signed in the late 1990s; the contract for Warrior Run's power will not expire until 2029.

It is difficult to determine an exact estimate of the amount of power still covered by long-term PURPA contracts. The existing contracts were catalogued during the industry restructuring process at the beginning of the decade, but since that time many have been paid down without attracting much attention, and hence they are difficult to itemize. One can approximate an upper bound for the amount of generation accounted for under PURPA contracts using available data.[5] Our estimate of an upper bound is reported in Table 3 for each of the states within the RGGI region. The first component is the combined heat and power generation devoted to the electric power sector (as opposed to powering specific commercial or industrial plants) (column 1), and the second component is the non-hydroelectric renewable generation (column 2) that was operating in 2003. The sum of these components (column 3) is a generous upper bound because not all of this generation remains under contract.

[5] We use the Energy Information Administration's historical data for these calculations. The data can be found at: http://www.eia.doe.gov/cneaf/electricity/epa/generation_state.xls.

Table 3. Components of PURPA Generation in RGGI Region, 2003 (*MWh)*

State	(1)**Total Electric Sector Co-Gen**	**(2) Non-Hydro Renewables Net of Electricity Co-Gen**	**(3) TOTAL Potential PURPA-Affected Generation**
CT	1,985,668	1,565,942	3,551,610
DE	109,420	0	109,420
ME	1,691,119	1,134,889	2,826,008
MA	5,378,236	2,026,483	7,404,719
NH	0	854,067	854,067
NJ	12,777,285	1,265,262	14,042,547
NY	15,614,581	1,751,570	17,366,151
RI	9,295	101,768	111,063
VT	0	405,136	405,136
TOTAL	37,565,604	9,105,117	46,670,721

The second step is to assess how much of the total power potentially under PURPA contract in 2003 will remain under contract when RGGI would take effect. We estimate this to be 20% of our estimate of initial PURPA generation. We feel this is a cautious estimate, meaning that it is an upper bound of the amount of NUG power under long-term contract. This estimate reflects several insights gleaned from our conversations with PUC officials. First, most of the existing PURPA contracts will have elapsed by 2010 or soon thereafter, having been signed in the 1980s for periods of 20 to 25 years. Second, as noted above, many of the contracts were terminated early because they were not economical.

Hence, we conclude that these culling processes are likely to leave no more than 20% of our estimate of potential PURPA power in 2003 under long-term contract in 2010, and they do not account for a significant proportion of total generation. Even in Maine, we project that by 2010, long-term PURPA contracts will account for no more than 5.2% of the power generated in the state in 2003. Estimates of the amount of generation that will be affected are displayed in Table 4.

Table 4. Estimate of PURPA Generation in RGGI Region (*MWh*)

State	(1) **Total Potential PURPA Generation in 2003**	(2) **Potential PURPA Generation Remaining under Contract in 2010**	(3) **Potential 2010 Generation (Column 2) as Share of 2003 Total Generation**
CT	3,551,610	710,322	2.43%
DE	109,420	21,884	0.32%
ME	2,826,008	565,202	4.23%
MA	7,404,719	1,480,944	3.12%
NH	854,067	170,813	0.80%
NJ	14,042,547	2,808,509	5.02%
NY	17,366,151	3,473,230	2.57%
RI	111,063	22,213	0.40%
VT	405,136	81,027	1.35%
TOTAL	46,670,721	9,334,144	2.91%

Interestingly, officials in several state PUCs noted that despite the failure of PURPA contracts to provide cost savings as predicted relative to other forms of electricity generation, there remains political support for using long-term contracts to spur the growth of renewable generation. In fact, PUC officials in Massachusetts, Maine, Rhode Island, and Pennsylvania all mentioned that such a strategy remains under consideration in their respective states. If these or other states decide to increase the role of renewable generation by using PURPA-style contracts, it would raise the share of generation accounted for by long-term contracts. However, new contracts should be negotiated on the basis of expectations that account for the RGGI process.

Having analyzed how much PURPA generation will remain under long-term contract after RGGI takes affect, we turn to the issue of who benefits. As noted in section 3.1, the answer reflects the nature of the negotiations between the local PUC and the distribution companies. In the absence of compelling information to the contrary, we believe that it is likely that the entirety of the RGGI region mirrors New York and Vermont. Therefore, we judge that the benefits of the long-term PURPA contracts will accrue to consumers rather than to distribution companies.

3.4 Restructuring

In another effort to increase efficiency, many states, including most of those in the RGGI region, chose to liberalize their electricity sectors during the late 1990s and early 2000s. One of the most important aspects of this process was the compulsory separation or divestiture of generation assets from formerly vertically integrated utilities. The rationale for this policy was the fear that in its absence utilities would be unduly prejudiced against purchasing non-affiliated generation. This would undercut the desired improvements in efficiency and result in unnecessarily high prices to consumers. Divestiture came about in a number of different ways. Some plants were sold off to wholly independent firms, while others were transferred to unregulated affiliate companies. Still other plants remained under the control of their utility owners but were subject to new regulatory oversight. While all types of plants were divested, fossil fuel plants were especially likely to be separated from the operational control of the distribution utilities. Divestiture was common throughout the RGGI region, though some states appear to have experienced higher rates of divestiture than others. For instance, Bushnell and Wolfram (2005) found that all of the fossil fuel plants in Connecticut that they examined were divested as of 2003, whereas only 69 percent of those plants in New York were.

During conversations with various state PUC officials, we found further evidence of differences in the extent and manner in which control over generation was separated from the rest of a distribution utility. For example, in Maryland and Rhode Island, the formerly integrated utilities were compelled to disconnect themselves from their generating assets either by placing them in a legally distinct affiliate or by selling them to third parties. Not even voltage support units were allowed to remain under the direct operational control of the distribution utilities.

By contrast, in New Jersey and New York, the restructuring statutes themselves said very little about separation. Nevertheless, the majority of utilities' generation assets were placed into affiliates in New Jersey and sold off in New York. (New York utilities did keep some generation assets. For example, the New York State Electric and Gas Corporation retained ownership of a number of small hydroelectric facilities.) Though not compulsory, these actions did receive the approval of state PUCs.

In Massachusetts, legislation provided strong incentives for the sale or legal separation of non-nuclear facilities from distribution utilities, though it did permit utilities to pursue intra-firm structural separation. The incentives (which were related to the amount of stranded costs that could be recovered) proved sufficiently large that all of the generation assets were sold to fully independent third parties. None were placed in legally distinct affiliates. Other states like Maine pursued a broad policy of separation but allowed utilities some leeway in case it became clear that retaining some generating units for reliability purposes was efficient.

The restructuring process, and especially the divestiture of generation assets, produced several types of fixed price generation contracts. First, divestiture led to bilateral contracts between the buyers and sellers of the generation assets. Just like the nuclear contracts discussed above (themselves a special form of divestiture contract), the deals between fossil fuel plants and their former owners helped both parties to manage their risks. Often, these divestiture contracts were used by utilities to lock in generation for the new “standard offer service” (SOS) rates they offered to consumers.

These rates were the successor to the standard, cost-of-service rates that consumers had received prior to restructuring. Temporary and generally set at a fraction of the last cost-of-service rate, the SOS arrangements were designed to give the public time to prepare for and learn about competitive pricing. Our survey produced no evidence that any RGGI region divestiture or SOS contracts were signed for longer than five years or extended beyond 2004.

When the transition period for SOS rates ended, most consumers shifted to “default service” rates, which are sometimes referred to as “provider of last resort” rates. These are the rate options that consumers receive if they choose not to select one of the competitive options. The power provided under the default rate typically is procured through competitive auctions in which generators bid to supply a given amount of power for a given price. Our survey of different state PUCs overwhelmingly suggests that the contracts for default load are only for between one and three years. This means that generators will have plenty of time to factor in the effects of RGGI when making any future contracts.

3.5 Tolling Contracts

Tolling contracts are different from traditional long-term contracts in which the owner and operator of a given facility commits to providing a certain amount of electricity in exchange for a given amount of money. Under a tolling contract, the owner and builder of the physical plant is removed from its day-to-day operations, having sold the right to the output of the plant to another party, generally the plant’s fuel supplier. By doing so, the builder is able to lock in a return on the capital investment. The operating partner controls the extent to which power is produced and sold. In this sense, unless the operating partner enters into a long-term supply contract of its own, the effect of the RGGI program on the financial status of the operating partner is the same as facilities operating without contracts in the electricity market.

3.6 Other

We also explored whether long-term contracts might exist for other reasons. For example, due to the physics of electricity transmission and lack of transmission capacity, plants in some regions need to run in order to maintain network reliability. These plants have reliability-must-run contracts with the transmission grid operator, but our survey found that they typically are not more than a year or two in duration.

We also explored whether some states may have used long-term contracts to further economic development. For example, a plant in an economically depressed region could receive a long-term, must-run contract to ensure the creation of jobs. The desire to spur job creation in the western part of Maryland influenced the decision to award the Warrior Run PURPA contract. While political considerations definitely effect contract considerations, our survey did not produce any evidence that such de facto subsidies have a direct influence on generation contracts that is distinct from previous categories.

4. Conclusion

We are motivated to examine the role of fixed price contracts because of their potential effect on two important measures. One is the degree to which these contracts mitigate the change in electricity price due to a RGGI policy. Using the notation introduced in Section 2, the contracts lower average electricity price by a factor $s\,x$, which equals the share of generation under fixed price contract multiplied by the portion of sales to retail customers that pass through power purchased at the fixed price. The second effect is that the revenues to facilities under contract will be the contract price rather than the market price. Hence, these facilities will not benefit from the increase in market price due to the policy and potentially they may claim special compensation due to their inability to recover changes in costs through changes in electricity price.

Two factors affect whether facilities under long-term contract deserve special consideration. One factor is whether the contracts expire before the RGGI program takes effect or at least before emission reductions are substantial enough to have an important effect on an individual facility. Since the RGGI program is likely to implement a schedule that starts with small emission reductions in the first years, the program will not affect the cash flow of affected facilities until well after the program is implemented. Many of the long-term contracts that are in place today will no longer be in effect by 2010, and hence the facilities will not be constrained by the existing contracts.

The second factor is whether the contract was signed in a time period when parties reasonably could and should have anticipated climate policy affecting the electricity sector. Climate has been recognized as a major environmental issue since President George H. W. Bush signed and the U.S. Senate ratified the 1992 Rio de Janeiro Climate Convention. Leaders of all parts of industry were made aware of the potentially binding emission reductions that might be required when parties to the United Nations Framework Convention on Climate Change adopted the Kyoto Protocol in 1997. The RGGI process itself began in 2003 when New York Governor George E. Pataki sent letters to the 11 governors from Maine to Maryland inviting their states’ participation. The exact date at which contracting parties should be deemed to have fiduciary responsibility for anticipation of climate policy is debatable, but beyond this date there is little economic rationale for adjustments for contracts negotiated under the shadow of climate policy. At some point in time, parties should have been able to incorporate the possibility of regulatory change into their negotiations.

To assess the role of fixed price contracts, we conducted an informal survey of staff at PUCs and/or other informed individuals in each of the nine northeastern states participating in RGGI plus the observer states of Maryland and Pennsylvania. The results are organized according to six types of potential fixed price contracts. We find that three types of contracts are in evidence, and the magnitude of generation under each type of contract is summarized in Table 5. The first column of data in the table reports total generation by state in 2003. The next three columns report generation under fixed price contract for nuclear facilities, hydropower, and non-hydro renewable facilities operating under PURPA contract. The latter is an upper bound estimate. The fifth data column sums the potentially affected generation in 2003, and the sixth column adjusts this number to account for the amount of this generation that is expected to remain under the current contracts in 2010. The final column expresses the generation in 2010 as a percentage of total generation in 2003.

Our analysis suggests that if regional demand for electricity remained constant at 2003 levels, then no more than 13.8% of generation will still be under fixed price contract in 2010.[6] If there is an increase in total generation from 2003 to 2010, the percentage will shrink accordingly. For example, if electricity demand increases 13.4%, as suggested by growth rates derived from the Energy Information Administration's *Annual Energy Outlook 2005*, then only 12.2% of total generation will be accounted for by long-term contracts (Energy Information Administration 2005).[7] Table 5 also shows that the effect of long-term contracts is not equally distributed either among states or by fuel type. Of particular interest is the fact that three quarters of affected generation is in New York State, where more than half of affected generation is accounted for by two public power facilities.

Table 5 provides a basis for calculating the change in electricity price due to RGGI. The change in electricity price under RGGI is a weighted average of the change in the real time marginal cost and the generation under contract. We assess that all the savings are passed on to customers or in terms of the notation in section 2, that $x = 1$. We assess that the value of s is something less than 0.138. Therefore, we conclude that it is possible that the change in electricity price calculated in Burtraw, Palmer, and Kahn overestimates the true effect on retail customers by up to 13.8%.[8] Since we arrive at this estimate using cautious upper bound values, the overestimate is probably somewhat less than this.

The second question we address is how fixed price contracts affect the change in asset values. For a specific facility, this depends on whether that facility is under fixed price contract and, if not, on the change in revenues. As noted, on average the change in revenues in Burtraw, Palmer, and Kahn is overestimated by up to 13.8%. Knowledge about contracts affecting specific facilities is beyond the reach of this paper, but we can provide average estimates by categories of generators for the industry. These estimates are presented in Table 6. Contracts affecting nuclear and hydroelectric facilities are assigned directly to these technology categories. These facilities do not emit CO_2 and therefore will not face an increase in cost associated with the RGGI policy. The other

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[6] Note that in recent modeling by Burtraw et al. (2005) the average electricity price in RGGI is a composite of prices set in the three constituent North American Electric Reliability Council (NERC) regions (New England, New York, and Mid-Atlantic Area [MACC]), which are forecasted to differ by $20/MWh between New England/New York and MAAC in 2020. Thus, when trying to adjust the price effects from RGGI and different allowance allocation approaches for the presence of long-term contracts, one could disaggregate this 13.8% to find the percentage within each constituent NERC region. Given that most of the affected generation is in New York, there is likely to be some variability in the adjustment across the different regions.

[7] This crude growth estimate is based on the total growth in electricity demand of the three NERC regions that include RGGI states. The estimate is inexact because New Jersey and Delaware cannot be disaggregated from the remainder of the MAAC.

[8] This estimate is based on the assumption that the response in electricity demand to the 13.8% difference in the change in the retail price is too small to cause a change in the mix of generation technology.

types of contract that may be important are those related to PURPA, which can use a variety of fuel types. The vast bulk of the generation associated with this category comes from four prime movers: coal, petroleum, natural gas, and non-hydroelectric renewables.[9] Table 6 indicates that a large portion of nuclear and hydroelectric generation may be affected but that a much smaller portion of other types of generation are affected.

To illustrate how this information can be applied directly to the aggregate numbers in Burtraw, Palmer, and Kahn, let us consider the New York State example. The previous study calculates the change in the value of generation assets as the change in the present discounted value of revenues and costs. The existence of long-term contracts is not expected to have any important effect on the costs faced by different units. Disregarding the change in generation from these facilities, only the change in revenues needs to be considered in adjusting the predicted change in asset values.

Table 6 reports that about 30% of nuclear generation in 2003 will remain under long-term contract in 2010. Therefore, the actual change in revenue for each unit of electricity generated by nuclear plants ($/MWh) is only about 70% of that estimated in the previous study. Because nuclear units face no increase in costs, the change (an increase) in the asset value of the nuclear units in New York is likely to be only 70% of what was reported previously. Since we identify the nuclear units specifically, the change can be attributed directly to the firms owning those units. Similarly the owner of the affected hydroelectric units is known. However, the owners of the affected PURPA units listed in Table 6 are not known and in the absence of additional information that might be provided by firms, to adjust the predicted change in revenues, one could apply the percentages to all generation of that fuel type before recalculating the expected change in asset values.

In summary, the results of our survey suggest that long-term contracts for electricity generation are not widespread in the RGGI region. States may want to consider their status on a case-by-case basis when making decisions about the initial distribution of emission allowances, but this should be done in the context of the effect of the RGGI policy on the portfolio of generation assets owned by a firm. Depending on the nature of the contracts, it may make sense to make adjustments to allowance allocations in different ways. However, it seems unnecessary to allow the existence of this group of contracts to dictate the design of the overall allocation scheme.

[9] A fractional amount of generation is associated with “Other Gases” or “Other” fuel sources.

Table 5. **Summary of Affected Generation (*MWh)***

State	Total Generation (2003)	Affected Nuclear (2003)	Affected Public Hydroelectric (2003)	Upper Bound Total Potential PURPA Affected Generation (see Table 3) (2003)	Total Affected Generation (2003)	Projected Affected Generation (in 2010)	Projected Affected Generation in 2010 as Share of 2003 Generation
CT	29,211,997	-	-	3,551,610	3,551,610	710,322	2.43%
DE	6,793,275	-	-	109,420	109,420	21,884	0.32%
ME	13,360,664	-	-	2,826,008	2,826,008	565,202	4.23%
MA	47,535,574	-	-	7,404,719	7,404,719	1,480,944	3.12%
NH	21,245,461	-	-	854,067	854,067	170,813	0.80%
NJ	55,915,704	-	-	14,042,547	14,042,547	2,808,509	5.02%
NY	135,172,639	12,292,665	18,195,276	17,366,151	47,854,092	33,961,171	25.12%
RI	5,578,298	-	-	111,063	111,063	22,213	0.40%
VT	6,021,886	4,444,152	-	405,136	4,849,288	4,525,179	75.15%
TOTAL	320,835,498	16,736,817	18,195,276	46,670,721	81,602,814	44,266,237	13.80%

Table 6. Projected Affected Generation as Share of 2003 Generation

State	Affected Nuclear	Affected Public Hydroelectric	Total Affected Coal	Total Affected Petroleum	Total Affected Natural Gas	Total Affected Non-Hydro Renewables	Total Affected Generation
CT	0.0%	0.0%	7.5%	0.1%	1.6%	0.0%	2.4%
DE	-	-	0.5%	0.0%	0.2%	-	0.3%
ME	-	0.0%	20.0%	0.0%	2.0%	7.5%	4.2%
MA	0.0%	0.0%	0.0%	0.3%	4.8%	0.0%	3.1%
NH	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%
NJ	0.0%	0.0%	6.1%	4.0%	13.7%	1.9%	5.0%
NY	30.2%	75.2%	1.1%	0.2%	10.1%	3.9%	25.1%
RI	-	0.0%	-	6.4%	0.0%	0.0%	0.4%
VT	100.0%	0.0%	-	0.0%	0.0%	0.0%	75.1%
Total	15.9%	60.0%	2.2%	0.4%	6.8%	2.4%	13.8%

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