ESTIMATED MARKET EFFECTS OF THE NEW YORK RENEWABLE PORTFOLIO STANDARD

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I. Executive Summary

A. Background

This report analyzes the market impact of the Renewable Portfolio Standard (RPS) ordered by the New York Public Service Commission (NYPSC) in September 2004.[1] The RPS policies are aimed at increasing the proportion of electricity produced from renewable resources in New York from approximately 20 percent to 25 percent by 2013. This goal is to be accomplished by providing financial incentives to encourage the development of renewable resources that serve the New York ISO (NYISO) markets. Under current proposals, the program is to be administered by the New York State Energy Research and Development Authority (NYSERDA) which will establish a solicitation process that would procure sufficient resources to meet the renewable portfolio targets.

The NYISO requested that Potomac Economics evaluate the potential market impacts of the RPS policies. Our review of the RPS policies focuses on two areas that represent the most significant economic issues. The first is the short and long-run effects on energy and capacity prices as the result of the addition of new low-marginal-cost RPS resources. This impact is assessed by estimating energy market and capacity market prices with and without the renewable resources that are assumed to result from the RPS policies. In differentiating between the short- and long-run effects of the RPS policies, the long-run is a timeframe in which entry and exit decisions will fully adjust capacity levels in response to the additional RPS resources. The report finds that in the long run, the net costs of the REC payments for consumers in New York will be $174 million annually.

Our second area of analysis examines how alternative procurement mechanisms can impact the market through the location decisions of renewable developers. In general, this assessment evaluates whether the extent to which the alternative procurement mechanisms provide efficient incentives for renewable resources to locate where capacity is most valuable, and the extent to which they provide for efficient allocation of risk.

[1] *Renewable Portfolio Standard*, New York Public Service Commission Case 03-E-0188.

Our analysis of price impacts is based on cases modeled for us by General Electric Power System Engineering Consulting (GE-PSEC) using the GE Multi-Area Production Simulation model (GE MAPS). In turn, these models were based largely on the assumptions about the RPS policy that have been developed by the New York Department of Public Service (DPS) in conjunction with NYSERDA. DPS and NYSERDA produced a comprehensive cost study, hereinafter "the DPS/NYSERDA Cost Study".[2] The cost study was based on simulations using key assumptions regarding the type of resources that are projected to be installed under the RPS policy during the 2006-2013 time period. We used many of the key assumptions including, but not limited to, the timing of the RPS resource investments, the capacity and technology of the new resources, the short-run and long-run NYISO load, and future non-RPS retirements and additions.

The projected resource additions are specific regarding their location, technology, and capacity. It is projected that 4500 MW of renewable capacity will be added by 2013. Of this amount, almost 50 percent is expected to be wind resources in Western New York and almost 25 percent is expected to be hydro resources from Canada.[3,4] Canadian RPS resources will flow over interfaces located in the Western portion of the New York Control Area. Hence, 75 percent of the anticipated RPS resources will supply low-cost energy to the part of the state West of the Central-East interface. *A priori*, we expect the primary price impact to be in the West.[5] Indeed, as discussed more below, our analysis shows this to be the case.

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2 "New York Renewable Portfolio Standard Cost Study II", Department of Public Service, *et al*. NYPSC Case 03-E-0188, February 2004, p. 2. Various elements of this study were revised and became part of the PSC Order in this case and we rely on many of the assumptions and conclusions underlying the study. As explained more below, we did not use the assumption that Canadian Hydro RPS resources were dispatched strictly off-peak, as the cost study assumes.

3 *Id*. p. 12.

4 Because of the significant addition of wind resources that are expected, NYSERDA has made a more focused analysis of the integration of wind resources. This study was conducted by GE-PSEC, i.e., "New York State Wind Integration Study," for the NYISO by GE-PSEC (January 2005 Draft), hereafter "the GE Study".

5 Unless otherwise stated to the contrary, our reference to "West" refers to the area of the NYISO control area west of the Central-East interface.

B. Summary of Analysis and Conclusions

The explicit goal of the RPS standard is to increase the reliance of the New York markets on renewable energy resources. We take this as a given rather than attempting to forecast the likely success of the RPS policies. The purpose of our analysis has been to assess the impact that this altered production mix will have on the NYISO electricity markets. These markets include the energy spot markets and the capacity market. The market impacts arise from the location, timing of installation, cost characteristics, and technical operating attributes of the RPS units.

As noted above, we analyze both short-run and long-run effects. The short-run and the long-run are distinguished by assumptions regarding entry and exit of new generation capacity. In the short-run, we assume prices do not affect entry and exit decisions – installed capacity is fixed. We assume a base year of 2008 for the short-run cases. In the long-run, we assume entry and exit occurs so that system is in long-run equilibrium, i.e., no capacity surplus or shortage exists. Consequently, in the short-term, we are concerned with the effect of the RPS policy on energy and capacity prices and we estimated these prices for a "base case" with no RPS resources and an "RPS case", which includes the anticipated RPS resource additions.

In the long-run, we are concerned with energy and capacity prices, as well as the likely changes in investment and retirement decisions by New York suppliers. The prices formed in the energy and capacity markets govern entry and exit decisions, which in turn affects the energy and capacity market prices that will prevail in the long-run. We assess the long-run effects by estimating a long-run equilibrium in the year 2013 for both a base case an RPS case.

In addition to estimating the short-run and long-run effects of the RPS resources, we also evaluate the alternative procurement approaches, focusing on the incentives inherent in the two primary alternatives. A main element of this assessment relates to the incentive to locate the new RPS capacity in areas where capacity has its highest value. Our assessment is qualitative. We have not attempted to quantify the implications of alternative procurement mechanisms with respect to the quantity, type, or location of the RPS resources.

1. Short-Run Market Impacts

We analyze two primary short-run market impacts: The short-run energy market impact and the short-run capacity market impact. The short-run energy market impact arises mainly from fact that most of the renewable resources have very low marginal costs and would, therefore, generally be inframarginal and tend to reduce the location-based marginal prices (LBMPs). The short-run capacity market impact arises mainly from the addition of new capacity in the form of RPS resources. We estimated these short-run effects by examining the impact in the year 2008. By 2008, it projected that a substantial portion of the RPS resources will be installed. The year 2008 is also the base year used by GE-PSEC in its wind analysis. Accordingly, we found it suitable as a base year for our purposes.

In order to asses the energy market impact, we use the base case that GE-PSEC estimates assuming the addition of no RPS resources but including the currently projected additions and retirements.[6] We then compare the outcomes to an RPS case, in which RPS resources are added to the extent they are projected to be on line by 2008.[7] The basis of the comparison is the spot energy prices produced by the simulation model. These prices are the result of an average of three scenarios: For both the Base Case and the RPS Case, we run three scenarios with differing load assumptions: (i) the 2008 load assumptions of the GE Wind Study; (ii) an extreme-load case where peak load levels are 2 percent higher than the normal 2008 loads; and (iii) a low-load case where peak load levels are 2 percent lower than normal.

Because the GE-MAPS model is limited in its capability to reflect shortages, we utilize a shortage pricing algorithm based on the level of excess committed capacity on the system in each hour. When the "excess capacity" is relatively low, the probability of shortage

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6 As discussed more below, we requested changes to certain inputs so the model would be reflect certain operating characteristics.

7 The RPS resources assumed to be in service in 2008 are listed in Appendix A.

increases. This probability is based on typical load forecast error rates and it is used to calculate an expected value of a shortage premium that is included in our estimates of energy prices.

Overall, we find that energy market price effects associated with the RPS additions are largest in the West, where prices decline by more than 3 percent. This is consistent with expectations given that the majority of the new RPS resources are wind resources located in the West or hydroelectric upgrades located in Canada that are imported into the West.

The second primary effect of the RPS resources would occur in the New York capacity market. The short-run effect of the RPS policy in the capacity market arises from the incremental supply of generating capacity available in NYISO capacity market that will alter the capacity clearing price under the NYISO capacity demand curves. The additional supply will tend to decrease prices. Our analysis focuses on the impact in the spot capacity market of the incremental RPS capacity, which should be reflected in forward capacity markets and transactions.

The NYISO establishes capacity prices for Long Island (LI), New York City (NYC), and the "Rest of the State" outside of NYC and LI. Our analysis indicates that prices in the Rest of the State decline by 18 percent as result of the RPS resources. However, there is no decline in capacity prices in NYC and LI because no significant RPS resources are projected to be added in these areas by 2008.

To estimate the total magnitude of the changes in energy and capacity prices, we have calculated a number of other statistics, including the total payments by loads and the net revenues that a new resources could expect to receive from the New York markets. We find that capacity payments decline by $80 million and energy payments decline by $171 million for a total decline of $251 million. The estimated cost to achieve the short-run RPS goals is $78 million annually, leaving a net short-run reduction in load payments of $173 million annually.

It is important to recognize that this is not driven by improvements in economic efficiency, but rather by the capacity surplus that the RPS subsidies will cause in the short-run. In additional, to the extent that some increase in retirements or postponement of investments is possible before 2008, the estimated reduction in load payments will be smaller.

2. Long-Run Market Effects

We calculate the long-run market effects by assuming energy and capacity prices will induce entry and exit by generators. The long-run impact of RPS policies is estimated by comparing a base case that is a long-run equilibrium with no new RPS resources to an RPS case that is in long-run equilibrium. We assume the long-run equilibrium is attained in 2013, the last year where extensive modeling of the RPS projects is available and a point in time where sufficient entry and exit could occur. To model the load in 2013, we use the GE-PSEC base case and increase the 2008 load by 6.1 percent based on the NYISO load forecast. From this basis, we also develop the extreme-load and low-load cases as in our short-run analysis. Also like our short-run analysis, we adjust the resulting energy prices to account for the expected value of possible shortages, as discussed in more detail below.

For the long-run base case, we use existing projections for retirement and additions and estimate the long-run equilibrium capacity level and the associated energy and capacity prices. Our analysis indicates that the current capacity projections will result in a surplus of 400 MW of capacity. Accordingly, our long-run base case capacity and energy prices are based on 400 MW of additional retirements beyond those currently projected. In the long-run RPS case, current capacity additions and RPS additions create a surplus of approximately 1800 MW by 2013. Hence, our long-run RPS equilibrium reflects additional retirements of 1800 MW.

By definition, in both the base case long-run equilibrium and in the RPS case long-run equilibrium, the combined energy and capacity market revenue is sufficient to induce new entry at a specific location in New York. For our analysis, we find that the marginal location for new entry is in the East outside New York City and Long Island. We chose this location for two reasons. First, the West prices are low relative to the East, making entry less profitable there. Second, entry costs in NYC and Long Island are exceptionally high and there is already a significant quantity of new capacity assumed to be added in those areas in the base case.

Our long-run cases show that in addition to inducing 1800 MW of retirements, the RPS resources will tend to shift the revenues from the energy market to the capacity market over the long-run. We project that energy revenue for a typical combined cycle generator will decrease by about 19 percent compared to the case without RPS resources. However, capacity revenues will increase by 17 percent to offset this change. From the perspective of load, we project that the total payments by loads for capacity and energy will decrease by $46 million annually. However, the total annual cost of achieving RPS is estimated to be $220 million, resulting in a net cost to loads in New York of $174 million annually.

3. Renewable Energy Credit Mechanism

In addition to the short-run and long-run market impacts, we also evaluate the mechanism by which new RPS resources will be procured. In order to advance the RPS program, the Commission's proposed rule calls for NYSERDA to determine a suitable mechanism for procuring the necessary RPS projects to attain the RPS goals. No specific mechanism has been established, but the contending alternatives have the common feature that will require eligible resources to make competitive offers to supply renewable energy in return for earning (per-MWh) Renewable Energy Credits (RECs). The REC payments are intended to supplement revenues earned by the RPS resources in other NYISO markets, primarily the energy and capacity markets. This subsidy is proposed in recognition that current market prices would not be sufficient to support recovery of the full cost of developing renewable resources in New York.

Subsidies like the REC payments support investment in resources that would not otherwise be economic. By giving them an economic advantage through the subsidy, they will be able to enter in larger numbers. However, subsidies generally raise certain risks. First, an inefficient subsidy can support the development of less efficient technologies that can displace more efficient or valuable technologies. Second, subsidies can also create uncertainty for new entrants. This can occur if new entrants believe that additional subsidies may be introduced in the future that would devalue their investments. This increases the risk of entry, ultimately increasing market costs and prices.

While the potential adverse effects of subsidies are well-recognized, it is equally well-recognized that subsidies can produce countervailing benefits. A subsidy can reflect benefits that are not fully captured by the markets. Cleaner air, for instance, provided by RPS resources is an example of benefits that are external to the NYISO markets. If policymakers determine that the benefits justify the subsidy, it should structured as efficiently as possible. It is outside the scope of this report to evaluate the potential costs and benefits of the RPS subsidy. However, we do evaluate the alternative REC procurement methods to provide assistance is structuring the subsidy as efficiently as possible.

The key difference between the alternative REC mechanisms that are proposed is whether the REC is fixed or variable. Under a fixed REC, the renewable resource earns a constant REC for each MWh of output. The REC would not affect the revenue that a supplier can earn in other NYISO markets or under a bilateral contract. Hence, the total revenue that can be expected by an RPS resource will be the sum of the REC and the other market revenue, which would vary in each hour.

Under a variable REC, a renewable resource is paid an amount necessary to cause the total imputed revenue a supplier receives for its output to be fixed. The REC in this case is the difference between the fixed price and the LBMP. For example, if the fixed price is $60 per MWh and the LBMP is $35, the supplier would receive a REC in that hour of $25 per MWh. This has been referred to as a “contract-for-differences” (CFD) although it differs from a typical CFD because it is linked to the actual output of the unit.

Under the fixed REC approach, eligible RPS resources will compete by making fixed REC offers. Under the variable REC or CFD approach, eligible resources will compete by offering a fixed total hourly payment where the REC makes up the difference between the hourly earnings from NYISO markets to ensure a fixed hourly payment.

The mechanism that is selected can have important implications for market efficiency. To evaluate the relative merits of the two alternatives, we propose three general efficiency principles that be considered in selecting the preferred mechanism: (1) it should result in bidding behavior that would contribute to efficient dispatch; (2) it should promote efficient investment decisions; and (3) it should allocate the market risk to the parties in the best position to manage it.

Our analysis of the alternative mechanisms leads us to conclude that the fixed REC approach best satisfies these efficiency principles. The main advantage of the fixed REC is that it provides more investment efficient incentives because the total revenues a supplier would receive would vary with the underlying prices in the NYISO markets. Therefore, investments made in resources in more valuable locations or investments made in resources that can produce at peak hours when prices are the highest would provide higher overall revenues to the supplier under a fixed REC (or, alternatively, would allow the developer to offer a lower fixed REC).

If the cost to install a resource in a high-value location is higher than the cost to install a resource in a low-value location, the resource in the high-value location may remain competitive due to the higher revenues from the NYISO markets. In this way, the incentives under the fixed REC mechanism will reflect how both the installed costs and the underlying market value of the energy and capacity vary by location. Similarly, some resources are more controllable and, therefore, can deliver higher quantities of power during peak periods when it is most valuable. Other resources are more intermittent and, therefore, tend to produce energy that has lower overall value to the system. Since the fixed REC would be additive to the NYISO market revenue, this alternative would more efficiently reveal the higher true value of renewable resources that are relatively more controllable. Therefore, we find that these incentives will more efficiently govern the new investments in renewable resources than the variable REC approach.

The variable REC or CFD approach is based on a fixed total price for the renewable output, including both the REC and NYISO LBMP. Under this approach, the NYISO LBMP has no effect on the suppliers' revenues. Therefore, the investment incentives would favor investment in locations where installed costs are minimized without regard to the value of the energy and capacity to the system. In addition, this approach allocates all future market risk to load.

II. Short-run Market Impacts of RPS

Our analysis of the short-run impacts of RPS policies is based on simulation of NYISO market prices in the energy and capacity markets under a Base Case regime compared to a simulation of prices under an RPS regime.[8] To assess short-run effects, we assume existing capacity does not exit the market nor does new capacity enter the market in response to the RPS-induced changes in the energy and capacity prices. Therefore, in the short-run base case, the stock of generation is fixed.[9] In the RPS case, the same capacity and load is assumed as in the base case, except renewable resources pursuant to RPS policies are added.

We use 2008 as the base year for the short-run analysis. By that time, a significant portion of the projected RPS capacity will be operable and the initial effects can be estimated. The energy market impacts of the 2008 base case are estimated using the GE MAPS model. The GE MAPS performs a daily commitment of generation and an hourly dispatch for the entire year for a region including the NYISO, ISO-New England, and PJM. A simplified representation of available supply is used to account for the adjacent regions in Canada. The model uses the estimated load at each bus in the region and simulates the electricity production using the technical characteristics of each generator to meet this load in light of the transmission grid characteristics.

The specific assumptions regarding load, generation, and other key operating characteristics used in the GE-MAPS model were developed by GE-PSEC in conjunction with NYSERDA in estimating various impacts of the RPS policies. We did not find reason to modify these assumptions significantly.[10]

8 All simulations were conducted by GE Power Systems Engineering and Consulting using GE MAPS modeling software. We worked with GE personnel pursuant to an agreement between NYISO and NYSERDA. Any references to simulations are to those conducted by GE-PSEC.

9 We include some retirements and additions that have already been projected to have taken effect for the base year independent of RPS. These entry and exit decisions were not based on projected price changes arising from RPS.

10 One main input that we requested be changed was the generator ratings. We found the ratings used in the model to be higher than the actual historical ratings in the NYISO commitment and dispatch models.

The short-run capacity market impacts are estimated using the NYISO capacity demand curve. The NYISO has recently proposed ICAP demand curves through 2008. We used August and December to represent the summer and winter spot markets, respectively. For the supply curves, we used the 2004 spot market supply curves for August (for summer) and December (for winter), adjusting the bid prices for inflation at an annual rate of 3 percent to 2008. New additions, including the RPS resources are assumed to be price takers in the capacity market. The effect of these assumptions is that the supply curve is "shifted" to the right and intersects the demand curve to set the market clearing price.

A. Short-Run Energy Market Impacts

To estimate the short-run impact of the RPS on the energy market, we compare the 2008 energy market prices estimated by the GE MAPS model with the inclusion of RPS resources to the prices estimated without including the RPS resources. We choose 2008 because it is a point in time by which a substantial portion of RPS resources are projected to be on line and providing energy to the NYISO markets. For purposes of estimating potential short-run effects of RPS, we assume the timeframe will not allow substantial changes in investment or retirements.

The GE MAPS model produces locational prices and output for each generator bus on the NYISO grid for each hour of the year. GE-PSEC conducted the 2008 simulations and provided us with the model output. We requested that six scenarios be estimated for the short-run analysis: three scenarios for the base case and three scenarios for the RPS case. The three scenarios are a low-load case, a medium load case, and a high-load case. The medium load case is the standard load case based on NYISO projection of peak load for 2008. The low-load and high-load cases are deviations from the medium load case. These deviations are based on NYISO forecasts of load variance. The motivation for the three scenarios was to ensure that revenues reflect a normal variation in system conditions.

We also account for load forecast errors that are typical on the NYISO system. In particular, in the GE model units are committed a day ahead of when they are scheduled for dispatch. The system is always perfectly committed, even though load forecast errors occur in reality. If the forecast error results in an under-commitment of the system, shortages conditions can arise – i.e., reserves are used to meet energy needs. When shortages conditions arise, the LBMPs in the area where the shortage occurs will include the economic value of the reserve capacity that is forgone.

Since the GE MAPS model does not include forecast errors, shortages will be much less likely than in reality. Because shortage pricing is a critical element of total energy market revenues, we developed a method to estimate the probability of shortage in each hour based on the unloaded capacity and the historical forecast errors. Using these values we can estimate an expected shortage price adder in each hour that equals the probability of the shortage times the likely shortage price increase.

Our method uses the historic load forecast errors from 2004 to develop a distribution of forecast errors for future years. For each hour, we calculate the amount of excess capacity available to meet system load and can use the historical error to calculate the probability the system will be in shortage.

We define excess capacity as the unloaded capacity on committed units (including capacity on gas turbines (GTs) that are not already running) less the reserve requirements.[11] We assume a state-wide reserve requirement of 1950 MW which reflects 1800 MW of operating reserves plus approximately 150 MW of regulation. We assume an East reserve requirement of 1000 MW.

In a statewide shortage, we assume 30-minute reserves are short and we increase the LBMP by a "State Adder" of $200 per MWh based on the 30-minute reserve and regulation demand curves. The total state adder is the probability that the forecast error is large enough to create a shortage times the blended price – i.e., *probability of shortage x $200*. In the East, we assume the shortage is in 10-minute reserves and we establish an "East Adder" that is the 10-minute reserve price times the probability of shortage – i.e.,

[11] We also make some adjustments to this value. First, we assume that some portion of the excess capacity will be served by GTs. But, because GTs sometimes fail to start when they are dispatched, we reduce the amount of excess capacity to reflect the probability that a GT will fail to start when called.

$500 x probability of shortage. When both the State and the East are in shortage, the total adder is the East adder plus the State adder.

As an example, suppose excess capacity is 150 MW state wide on a day that has a state-wide load of 30,000MW. Suppose also that, according to historical forecast errors the probability that the NYISO under commits by more than 0.5 percent, i.e., by more than 150 MW is 7%. The probability that the state-wide reserves cannot be met is 7% and the price, therefore is equal to LBMP + .07* $200 = LBMP + $14. In instances when excess capacity is negative (which is relatively rare), we use a price equal to the LBMP plus the reserve price reduced by the probability that a sufficient over-forecast could occur provide enough additional capacity to avoid shortage. In such a case, the price is calculated as LBMP + $200 – (Probability of over-forecast) * $200.

In most hours, the probability that load is under-scheduled by an amount large enough to cause a shortage is very close to zero so that in most hours the expected shortage price adder is very close to zero. Table 1 summarizes the frequency with which the LBMP is increased by more than $20 as a result of expected scarcity. The table shows the number of hours the adder is greater than $20.

Table 1: Summary of Hours with Significant Scarcity Adder - 2008

	East		State		Total	
	Base	RPS	Base	RPS	Base	RPS
Number of Hours Scarcity Adder is greater than $20/MWh	25	23	1	0	27	22
Average Magnitude of Scarcity Adder in hours when Adder > $20/MWh	$58	$52	$24	$0	$64	$54
Maximum Adder	$146	$116	$24	$11	$170	$123

The Table shows the adder in the East, the State, and the total. As discussed above, when there is a shortage in both the East and the State, then both the State adder and the East adder are included in the locational price. Accordingly, the Total adder indicates the aggregate effect of our scarcity price adder. The table shows that the incidence and magnitude of scarcity prices declined as a result of RPS resource additions.

In addition to the adjustments to the energy prices, we sought to reflect other crucial facts concerning NYISO markets. In particular, as noted above, we asked GE-PSEC to adjust generator ratings into the MAPS model to reflect the fact that units typically are not available for commitment or dispatch at their full seasonal capability. Indeed, unit rating average 85 percent of their seasonal ratings. We provided GE-PSEC our estimate of the actual historical ratings based on data for 2004. We also derated ISO-NE and PJM units assuming the same average derating levels as exhibited by the New York Units.

For each both the non-RPS case and the RPS case, we average the prices from the three load scenarios to arrive at our estimated price at each bus for each hour. The energy price results are summarized in Table 2.

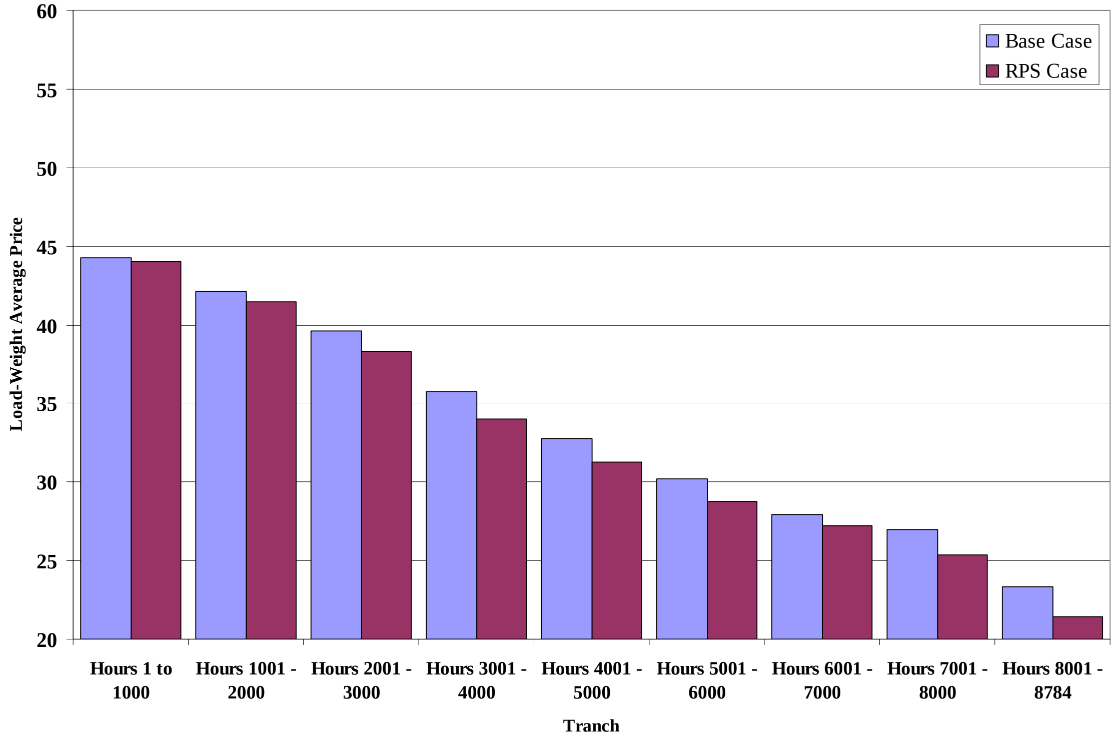
Table 2: Summary of Short-Run Energy Prices

	Base Case	RPS Case	Change	% Change
West	$ 34.83	$ 33.64	$ (1.19)	-3.4%
East	$ 39.88	$ 39.09	$ (0.79)	-2.0%
NYC	$ 38.74	$ 38.45	$ (0.29)	-0.7%
Long Island	$ 55.64	$ 54.82	$ (0.81)	-1.5%

Note : Dollar amounts are per MWh.

As the Table shows, prices decline on average in each of the four locations. The largest decrease occurs in the West. This is not surprising because the West is where the bulk of the RPS resources are installed. In addition, in many hours when the Central-East Interface constraint is not binding, the additional inframarginal resources in the West will reduce prices in the East, as indicated in the Table. Our next analysis examines the difference in prices at different price levels. We ordered the prices from highest-price hour to the lowest-price hour and divided them into 9 tranches – the first eight tranches are 1,000 hours each and the last is the remaining 784 hours (2008 being a leap year with 8784 hours). For each tranch we calculate a load-weighted average hourly price for the base case and the RPS case. The analysis for average prices in the West is shown in Figure 1.

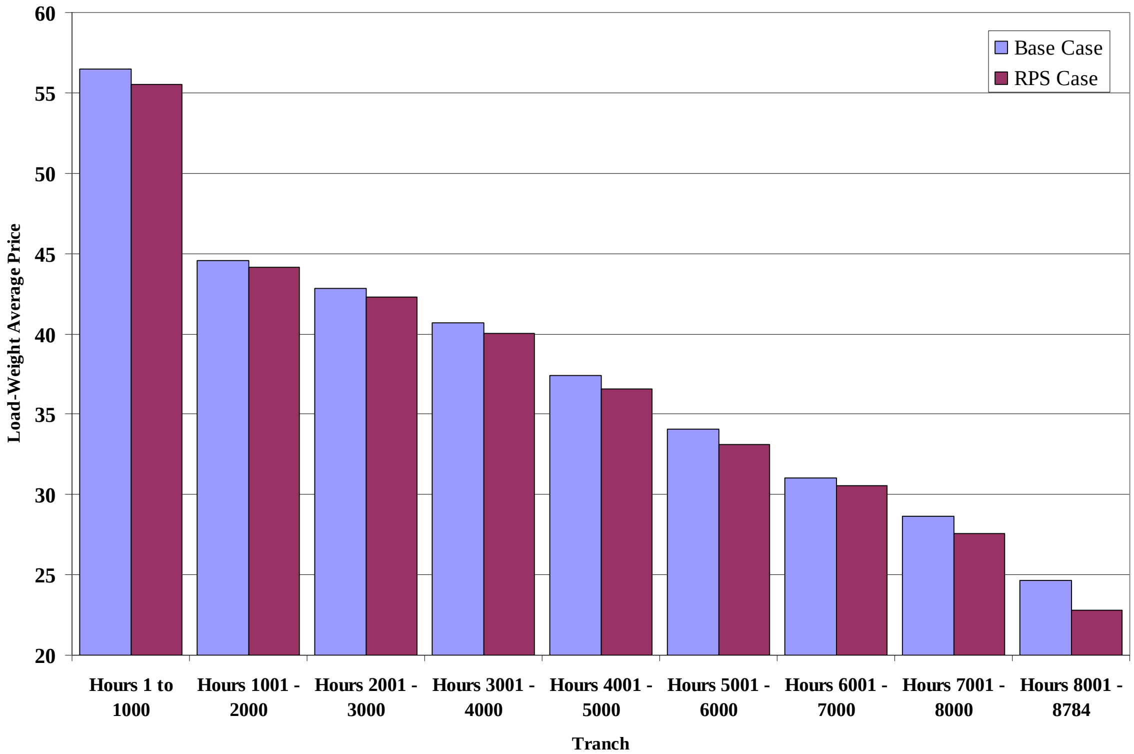
Figure 1: Comparison of Short-Run Energy Prices – West Average



As the chart shows, average base case price is higher than the RPS price at all price levels. During the lowest-priced hours, the average RPS price is roughly two dollars less than the average base case price. This indicates that the largest impact in both absolute and percentage terms is on West prices during the lowest-priced hours.

We also performed this analysis for prices in the East. The comparison of short-run base case and RPS results for the East are shown in Figure 2.

Figure 2: Comparison of Short-Run Energy Prices – East Average



Like the West prices, the base case prices are higher in every tranch. The highest-priced 1000 hours are significantly higher in both the base case and RPS case than the other hours. This is somewhat different than the West results where the price are higher but not by the same magnitude as in the East. This can be explained by the scarcity price adder that we calculate which is going to be more significant in the East than statewide.

To show how prices are affected in the highest-priced hours, we constructed price duration curves using the highest-priced 50 hours. A price duration curve shows the number of hours on the x-axis that the price equals or exceeds the price shown on the y-axis. The price duration curve for the West is shown in Figure 3 and for the East in Figure 4.

Figure 3: Price Duration Curve Short-run – West

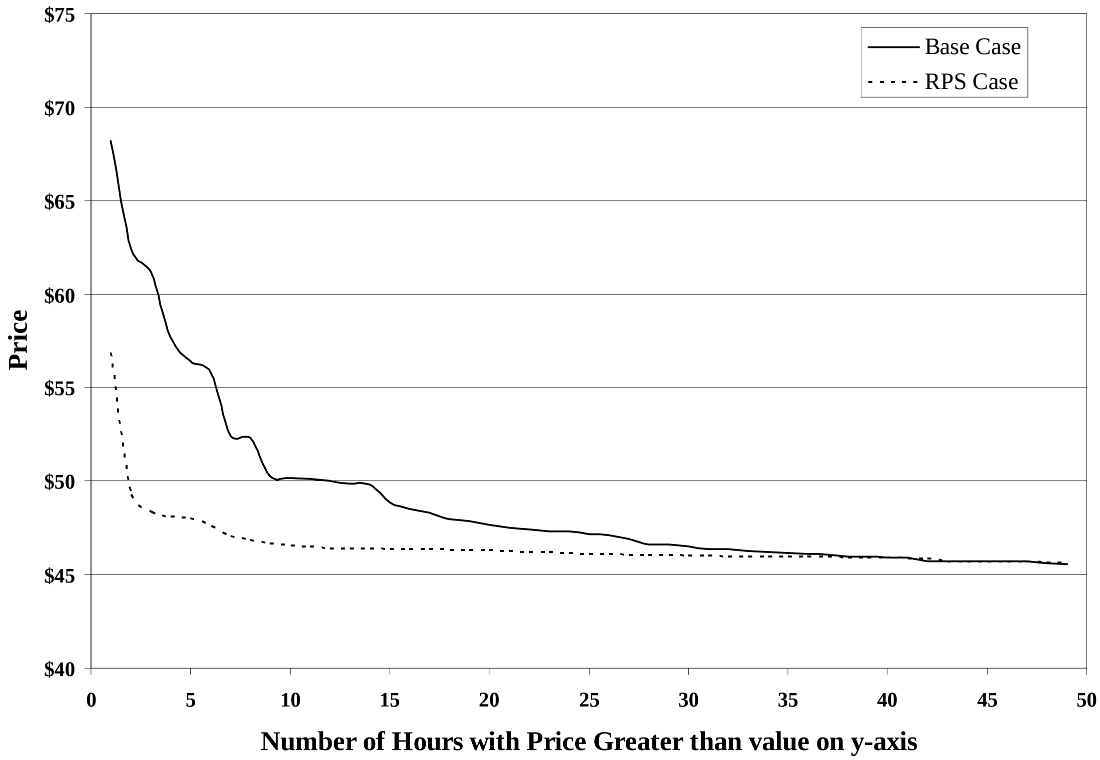
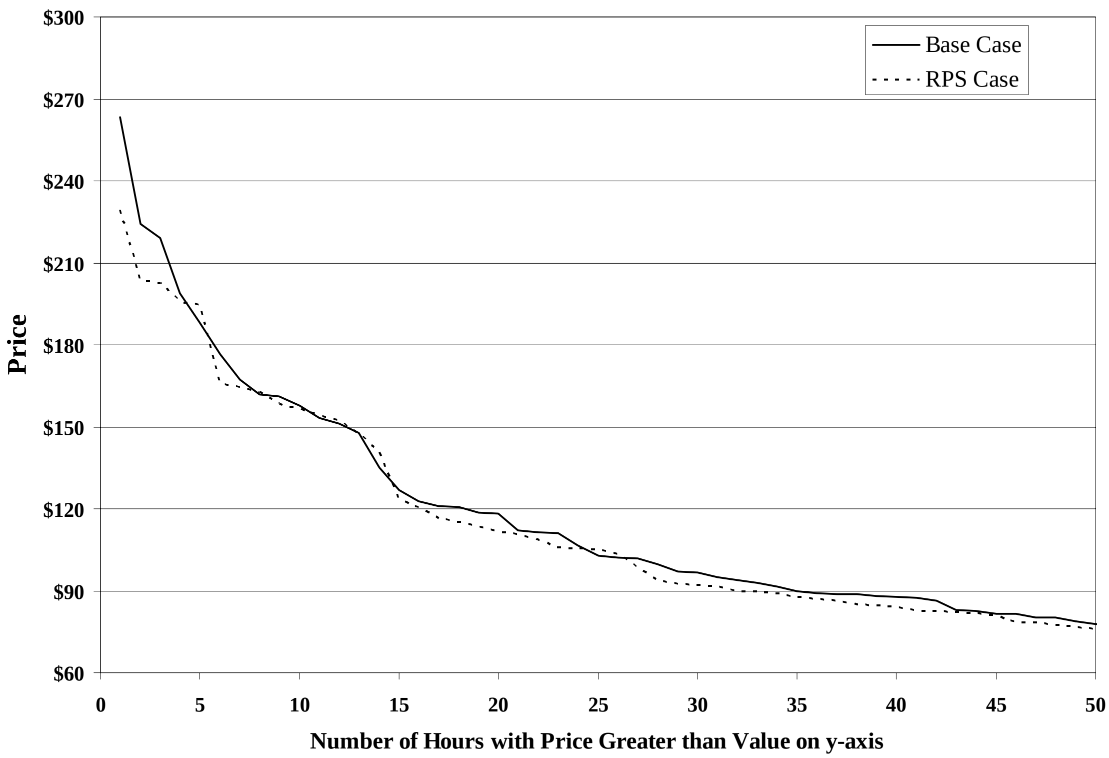


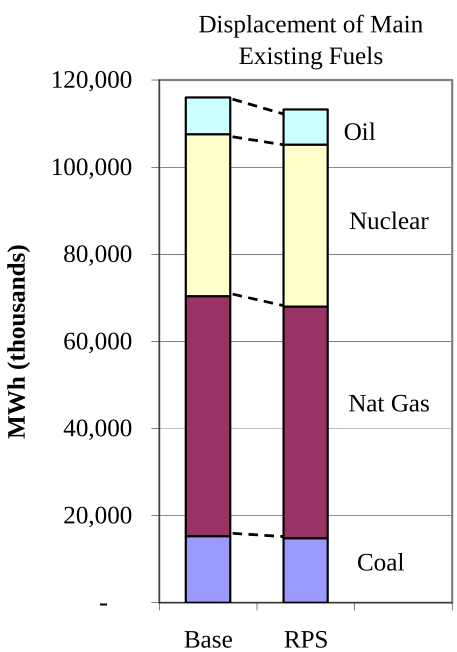
Figure 4: Price Duration Curve Short-run – East



In both cases, the price duration curves indicate that the prices diverge most substantially at the very highest-priced hours. This can be explained by the fact that RPS capacity reduces the probability of shortages in the short-run.

In addition to the price effects, we examined the displacement of generation that results from the installation of new RPS resources. Figure 5 summarizes the results for 2008.

Figure 5: Short-Run Fuel Displacement



Fuel Type	Change (MWh)	Change (%)
COAL	(504,458)	-3.3%
NAT GAS	(1,915,494)	-3.5%
MISC RPS*	857,231	
NUCLEAR	-	0.0%
OIL	(315,945)	-3.8%
OTHER	796	0.0%
WATER	118	0.0%
WIND	3,993,469	
CANADA IMPORTS**	995,560	31.6%
NON-CANADA IMPORTS**	(3,111,276)	-15.6%

Note: *MISC RPS includes new land-fill gas units, manure digestions, and biomass co-firing. **Import values shown are modeled flows rather than scheduled imports.

The figure shows that natural gas generation experiences the largest displacement as a result of the RPS resources (1.9 million MWh). On a percentage basis, oil generation experiences the largest displacement, but on a comparable level with coal and natural gas. This is consistent with expectations because oil and gas generation are the highest-cost generation in the state and most frequently on the margin. Hence, they are the first types of generation to be displaced. With respect to coal, it is displaced at a high rate because it is mostly located in the West, where the bulk of the RPS resources are added.

Besides native generation, a decline in non-Canadian imports represents the largest displacement both in volume and percentage. This is not surprising because much of the non-Canadian imports occur in the West where the RPS resources are concentrated, rendering them less economic as a source of supply.

A large increase in Canadian imports occurs as the result of over 500 MW of RPS resources added to Ontario Hydro and Hydro Quebec, which we assume are scheduled in peak hours. Our estimate of the RPS imports from Canada is substantially less than what was estimated for the NYPSC Order. In particular, the PSC Order estimated that about 2 million MWh of RPS energy would be imported from Canada. This is compared to the 995,000 MWh we estimate. The PSC estimate relied on the assumption that the RPS energy would be produced during off-peak hours to avoid the Canada-NYISO transmission limits. We assume the RPS resources compete with existing Canadian hydro resources for the interface during peak times. We judge this assumption to be the more likely result in reality. In other words, we expect the new RPS hydro resources in Canada to replace existing hydro from Canada when the interface is constrained.[12]

We also identified the changes in short-run production in each zone as the result of new RPS resources. In Table 3 we summarize the change in output by zone.

Table 3: Short-Run Zonal Changes in Energy Production

Zone	Base Case	RPS Case Total	RPS Output	Change	Change %
West Native	71,569,263	74,831,027	4,308,677	3,261,764	4.6%
West Imports	23,077,831	20,962,114	995,560	(2,115,717)	-9.2%
West Total	94,647,094	95,793,141	5,304,236	1,146,047	1.2%
East	39,554,670	38,936,620	479,665	(618,050)	-1.6%
NYC	23,677,210	23,147,664	-	(529,546)	-2.2%
Long Island	13,292,068	13,293,618	62,358	1,549	0.0%
Total	171,171,042	171,171,043	5,846,260	0	0.0%

The table shows that production in the West increases in the RPS case, but by a smaller amount than the total RPS resource production – total production increases by 1.15

[12] We were not successful in uncovering the rationale for underlying assumption in the PSC model.

million MWh but RPS production increases by more than 5 million MWh, implying a decreasing existing supply of more than 4 million MWh. There is also significant reduction in output in East locations. This is the result of lower-cost RPS production in Long Island and also lower-cost RPS resources in West making it into the East markets when the Central-East interface is unconstrained.

In Table 4 we show the load payments for energy between the base case and the RPS case.

Table 4: Load Payments for Energy

Load Payments in Short-Run Base Case	$6,380
Load Payments Short-Run RPS Case	$6,209
Change in Load Payments from RPS	-$171
Annual REC Payments in 2008	$78
Net Change in Annual Load Payments	-$93

Note : Values in millions.

The table indicates that energy payments by load decline by $171 million. This decline in load payments does not reflect renewable energy credit obligations. By 2008, these obligations are estimated to be $78 million annually, which results in a net decline in load payments of $93 million. Moreover, as discussed in more detail below, the decline in load payments is likely to be a short-run phenomenon because the lower prices are the result of surplus capacity, which will be eliminated in the long-run.[13]

B. Short-Run Capacity Market Impacts

Generators in the NYISO markets earn revenues in the capacity market by contracting with load serving entities to provide capacity or by selling capacity in the NYISO capacity auctions. The Installed Capacity (ICAP) market allows individual generators to

[13] Investors may also demand higher returns on new investment in the long-run to account for the risk of subsequent price declines arising from energy policies like RPS. We do not intend to suggest, however, that the higher long-run costs are not offset by the benefits of RPS. We only point out the costs and state policy makers can weigh these against the benefits.

sell capacity up to the expected availability of their units, recognizing the forced outage rates for each unit.

Our analysis of capacity market impacts is based on the shift in supply associated with the RPS resources and the NYISO capacity demand curve. We use the capacity to estimate the 2008 capacity prices with and without RPS resources. We assume all participants are paid in accordance with the spot market price for capacity. The spot market price, which is established using the proposed UCAP demand curve, adjusted for inflation, provides a basis for other forward capacity market prices (e.g., the monthly strip auction prices and bilateral capacity prices). In other words, arbitrage by participants should cause capacity prices in the bilateral market and the strip auction to converge to the spot price over time. Accordingly, we assume the estimated price in the monthly spot auctions is the price paid to all UCAP suppliers.

To estimate the 2008 non-RPS UCAP price, we use the 2007/2008 capacity demand curve recently proposed by NYISO and estimate a spot price for August and December to represent the summer and winter prices, respectively. The monthly spot market price is determined by the intersection of the capacity demand curve with the supply stack. We use the supply stacks used in August 2004 and December 2004 and increase the bid by 3% per the four years between 2004 and 2008. For the period 2004-2008, we identified about 1600 MW of net capacity additions. There are about 1400 MW of net additions in New York City and 260 MW in Long Island. There is a slight decline in net capacity in the locations outside of New York City and Long Island. For new additions, we assumed the equivalent forced outage rate (EFORd) is equivalent to the average EFORd for existing NYISO units (i.e., 5%).

We assumed that new capacity coming on line by 2008 will be price takers in the spot market. Because we use the existing supply offers (adjusted for inflation) the underlying assumption in our method is that the non-zero portion of the current supply curves will represent the non-zero portion of future supply curves, with additional capacity treated as price takers.

The NYISO auctions result in prices and allocations for three NYISO areas: New York City, Long Island, and the rest of the state. We constructed supply and demand curves using the proposed demand curve parameters and the existing supply curves to find the UCAP clearing price and amount procured. For NYC, we assume existing price caps remain in place through 2008. Table 5 shows our estimates of capacity prices for the summer and winter 2008.

Table 5: Estimated UCAP Prices

	2008		2004	
	Summer	Winter	Summer	Winter
New York Control Area	$2.62	$0.62	$1.17	$0.61
Long Island	$12.10	$10.10	$8.16	$6.21
New York City	$11.42	$7.12	$11.42	$7.12

Note : Prices are for kW-month.

As the table indicates, capacity prices increase slightly from 2004 to 2008. The increases are highest in Long Island and the lowest in the West. That prices increase is not surprising because the new demand curves for 2008 increase by 14 percent. In addition, peak demand increases slightly faster through 2008 than new additions. While there are about 1600 MW of net additions, peak load grows by 1800 MW. For New York City, price-capped units set the price in both 2004 and 2008, resulting in no change in NYC capacity prices.

To estimate the impact of RPS resources, we consider the RPS resources anticipated to be added by 2008,[14] which total 2200 MW of new resources. On-shore wind projects account 1475 MW of this total and hydro upgrades account for 527 MW. The remaining 200 MW consists of biomass co-firing projects and land-fill gas engines. The bulk of the anticipated RPS resources are located outside of NYC and Long Island, with the exception of 20 MW on Long Island.

[14] The anticipated RPS resources to be added by 2008 are in accordance with the assumptions in the October 2004 PSC Order.

Because the hydro upgrades are mostly located in Canada where the interface constraints prevent additional capacity imports, we do not give UCAP credit to Canadian hydro upgrades. To assign UCAP values to the other projects, we assumed availability factors of 10 percent for on-shore wind resources, 50 percent for (non-Canadian) hydro, and 80 percent for the biomass co-firing and the land-fill gas engines. For off-shore wind, which comes on line in the 2013 case described below, we assume an availability of 40 percent. These reliability values are based on discussions with NYISO and GE-PSEC personnel.

Applying the availability factors to the projected RPS units, the additional UCAP supply is 305 MW for 2008. We assume these units are price takers in the UCAP spot market. Using the same technique we used above to incorporate the 2008 net capacity additions, we add the RPS units and estimate the 2008 UCAP prices. The results are shown in Table 6.

Table 6: Impact of RPS on UCAP Prices -- 2008

	2008 without RPS		2008 with RPS	
	summer	winter	summer	winter
New York Control Area	$2.62	$0.62	$2.25	$0.41
Long Island	$12.10	$10.10	$12.10	$10.10
New York City	$11.42	$7.12	$11.42	$7.12

Note : Prices are for kW-month.

The table shows that of RPS has a significant impact only on the New York Control Area (NYCA) price (which is the rest-of-the state outside NYC and LI). This is not surprising because all of the RPS resources except for 4 MW on LI are located outside of LI and NYC. Indeed, no RPS resources are assumed to be added in NYC.

Table 7 shows the estimated change in revenue in 2008 from the addition of RPS resources, which recognizes the change in both prices and procurement amounts.

Table 7: Zonal Changes in Capacity Revenues

		NYCA	NYC	LI	Total
Base Case					
Summer 2008					
	Price (kW-Mo)	$2.62	$11.42	$12.10	
	UCAP Purchase (MW)	25,500	9,750	5,250	
	Revenue ($million)	$401	$668	$381	$1,450
Winter 2008					
	Price (kW-Mo)	$0.62	$7.12	$10.10	
	UCAP Purchase (MW)	26,653	9,810	5,345	
	Revenue ($million)	$99	$419	$324	$842
Total Base Case 2008		$500	$1,087	$705	$2,292
RPS Case					
Summer 2008					
	Price (kW-Mo)	$2.25	$11.42	$12.10	
	UCAP Purchase (MW)	26,250	9,750	5,250	
	Revenue ($million)	$354	$668	$381	$1,404
Winter 2008					
	Price (kW-Mo)	$0.41	$7.12	$10.10	
	UCAP Purchase (MW)	26,653	9,810	5,345	
	Revenue ($million)	$66	$419	$324	$809
Total RPS 2008		$420	$1,087	$705	$2,212
Revenue Change from RPS		-$80	$0	$0	-$80

In 2008 base case total capacity revenues are $2.29 billion and in the RPS case they are $2.21 billion -- a decrease of $80 million, or about 3.5 percent. The change in overall revenue occurs as a result of lower prices outside NYC and LI. The revenue in both NYC and LI are constant between the cases because demand and supply are virtually constant.

Recall from the previous section that energy payments decline by $171 million. Together with the $80 million decline in capacity payments, total electricity market payments decline by $251 million. This does not reflect the estimated $78 million in RPS costs, as noted above, which results in a short-run reduction in load payments of $173 million.

C. Net Revenue Analysis

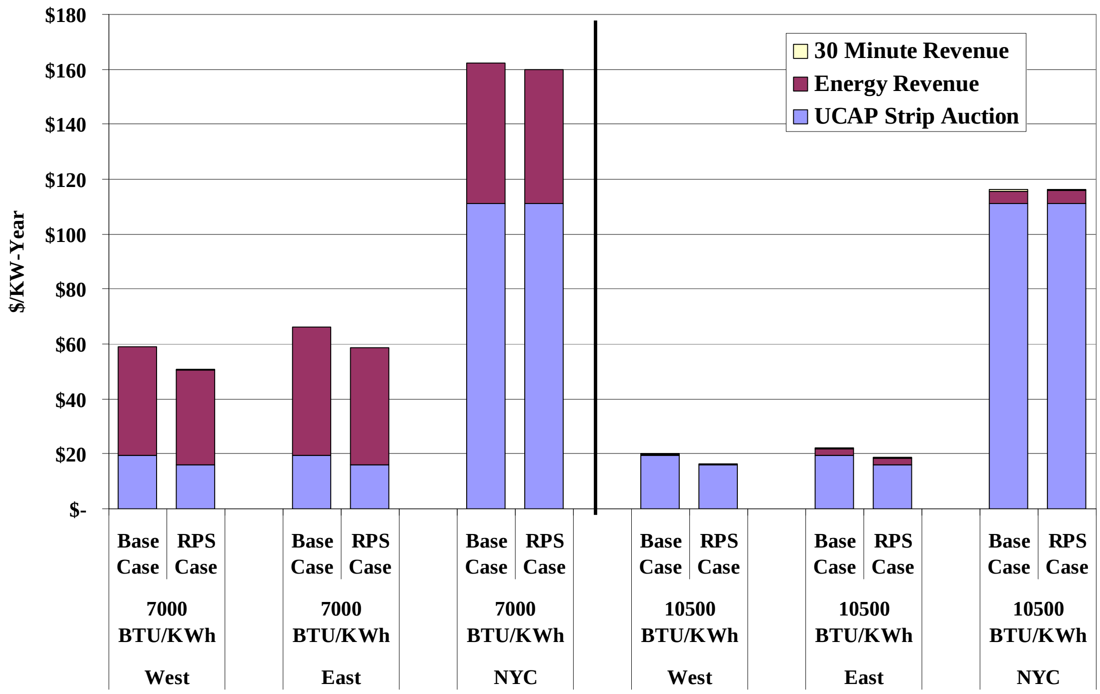
To evaluate the aggregate effects of the RPS on economic signals provided to suppliers by the NYISO markets, this section provides our analysis of the net revenues that would have been received in 2008 by generators at different locations in New York. Net revenues are the total revenues earned in the UCAP and energy markets less operating costs -- the free cash flow available to meet the generators' fixed costs. The stream of future net revenues governs suppliers' investment and retirement decisions -- if revenues are not sufficient to recover fixed costs (including return on equity), then new units will not be built and marginally profitable existing ones will not continue in service.

We analyze three locations in the State: The West (the area West of the Central-East interface, the East (the area East of the Central-East interface, but excluding NYC and Long Island), and New York City. In each location, we calculate net revenue for 2008 for both the base case and the RPS case.[15] We evaluate the net revenue for two hypothetical units – a unit with a heat rate of 7500 BTU/kWh (which corresponds to the efficiency of a new combined-cycle plant) and a unit with a heat rate of 10500 BTU/kWh (which corresponds to the efficiency of a new gas turbine). In calculating net revenue, we assume the unit is running in every hour when its incremental running costs, based on the heat rate and natural gas price, is less than the estimated energy price.

Because the introduction of RPS causes a decline in both energy and capacity markets, the net revenue earned by hypothetical units in all NYISO locations declines. Figure 6 shows the comparison of base case and RPS net revenue in the West, East, and New York City for these two hypothetical units.

[15] Our results are based on the energy prices calculated in the analysis above. In this way, it is based on the average of the low-load, extreme-load, and middle-load scenarios in the GE MAPS estimates used in the energy analysis.

Figure 6: Short-Run Net Revenue in the West and East -- Base Case v RPS



The figure shows that net revenue earned by a 7000 heat rate combined-cycle unit in the West declines from just under $59/kW-year to $50/kW-year. In the East, the decline is from $66/kW-year to $59/kW-year, a smaller decline because the RPS resources added in the West do not have as large an effect on prices in the East. In New York City, the decline is the smallest, primarily because capacity revenues do not change between the base case and the RPS case due to the fact that no RPS resources are added in New York City.

For the less efficient gas turbine, the net revenue declines from $19.60/kW-year to $16.10/kW-year in the West, most of which is the result of declines in the capacity revenues, because energy net revenues earned by the unit in the West are very low. In the East, revenues for the gas turbine are only marginally higher. In New York City, the net revenues are the highest, with the majority of the revenues attributable to the capacity market.

In the West and East, and in both the base case and the RPS case, the net revenues earned by a combined-cycle and the gas turbine are inadequate to encourage new investment. This is based on estimated annualized costs of a combined-cycle of $115/kW-year and for a gas turbine of $92/kW-year.[16] While we would not expect marginal units to be added in the West, the calculation of the net revenue is important in assessing the viability of existing generation.

For New York City, the net revenue for the hypothetical combined-cycle unit is above $160/kW-year in both the base case and the RPS case. For the less efficient gas turbine, the net revenue is comparable between the cases at about $115/kW-year. The $160/kW-year value is above the estimated cost of installing the combined-cycle unit based on a national average calculated by the Energy Information Administration, as noted above. However, the annualized cost of this unit in New York City is likely to be substantially higher. For the gas turbine, the NYISO estimates the cost to be $186/kW-year inside New York City, substantially above the current revenues.[17] While our analysis is indeterminate with respect to the combined-cycle plant, we do not find sufficient revenues under either the base case or the RPS case for entry of gas turbines. Hence, the analysis projects that the NYISO system will exhibit a capacity surplus in the base case that is exacerbated by the addition of RPS resources.

D. Short-Run Conclusions

The short-run impact of the RPS policies is to reduce prices significantly in both the energy and capacity markets. Our analysis indicates that on a proportional bases, the largest energy price impact is in the West, which is attributable to the fact that most of the new RPS resources are anticipated in the West.

These short-run reductions in energy and capacity prices will result in lower load payments (excluding REC payments) and lower net revenue for generators in the NYISO

[16] The estimated annualized cost of a combined cycle unit is on $99 estimate for 2003 in the Energy Information Administration Annual Energy Outlook 2005. For the gas turbine, we assumed the $87 per kW-year value estimated recently by Levitan and Associates and used by the NYISO in establishing the new proposed capacity demand curves.

[17] Annual cost estimated by Levitan and Associates for a new LM6000 gas turbine in New York City.

markets. It is important to recognize that these effects are expected short-run only, and temporary by definition.

In the next section we examine the likely changes in generating capacity in the NYISO in response to these economic signals. As discusses above, while the RPS policies result in overall lower payments for electricity, the calculations do not consider losses to investors as a result of reduced revenues eared by existing assists. Because the analysis is a short-run analysis, the reduced costs also do not reflect the higher long-run costs when uneconomic assets are forced from the market.

III. Long-run Market Analysis

In this section we analyze the long-run impact of RPS policies on the NYISO market. In the long-run we assume capital (i.e., generating capacity) freely exits and enters the market, eliminating any short-run shortages and surpluses. The end state either with or without RPS is a long-run equilibrium in which energy and capacity prices produce net revenue that provide marginal profitability for a entrant. In other words, expected market revenues are just high enough to cover an investor's fixed and variable costs, including a return on equity at levels commensurate with the risk of the project. Capital leaves the market (or does not enter) when expected net revenue is not sufficient and enters the market when revenue is more than sufficient.[18]

We estimate a long-run equilibrium for a base case without the RPS resources and a long-run equilibrium for an RPS case. This comparison will illustrate the impact that RPS policies will have on future entry and retirement decisions. For the long-run cases, we modeled the system in the year 2013. We chose this year for two reasons. First, this is the year at which RPS targets are to be met and there are accepted estimates of the new RPS resources that will be installed. Second, this date is sufficiently close to the present year that reasonable assumptions about market conditions can be made. However, the timeframe is sufficiently long to allow entry and exit.

To estimate the 2013 long-run equilibrium, we first estimated the energy and capacity prices under projected load and resources expected for 2013. We estimate this for both a base case and an RPS case. For 2013, the peak load is expected to increase by 1,700 MW from 2008 to a peak of 35,340 MW. Capacity additions net of retirements (excluding RPS additions) are assumed to increase by 424 MW from 2008 to 2013. [19] Because load

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[18] In any given year revenues may be affected by temporary load conditions that are offset by countervailing conditions in the subsequent years so that, on average, revenues may be higher or lower than the actual year's revenues. Our estimate of future revenues relies on the assumption of average load conditions. Therefore, revenue deficiency implies excess capacity. It may also be the case that market rules or operating procedures may be depressing market revenue. Although we do not preclude this possibility, we assume this is not the case.

[19] The projected load and resources for 2013 are based on the NYISO gold book for load assumptions. Additions and retirements are based on the assumptions used by GE PSEC in its work for NYSERDA in the case, assumptions which we found no reason to question.

is expected to increase faster than net additions, the surplus capacity in the 2008 case will decline by 2013. However, the addition of 2,300 MW of RPS resources between 2008 and 2013 will counteract this move toward equilibrium.

Based on these initial estimates of the base case and RPS case energy and capacity prices, we evaluated the net revenue for hypothetical units located East of the central-East interface (but outside New York City and Long Island).[20] It is this location where incremental capacity is most likely to be added, given that the West has the most capacity surplus and that incremental entry in New York City and Long Island is costly due to land use constraints and costs. Accordingly, if units in the East are earning revenue close to the level where profitable entry can occur, then the system is in long-run equilibrium. The initial estimates indicated a capacity surplus in the East in both the base case and the RPS case under the current load and resource projections.

We then produced a number of scenarios with varying levels of retirements for the base case and the RPS case to find the long-run equilibrium level of capacity. Based on the results of these scenarios, we find that 400 MW of retirements are needed to achieve long-run equilibrium in the base case and 1800 MW of retirements to achieve long-run equilibrium in the RPS case. Energy and capacity prices with these retirements had the effect of providing net revenue levels that are close to the level that would make entry marginally profitable. To find the long-run equilibrium, we track the changes in the net revenue for the combined-cycle and gas turbine plants, seeking conditions that would make either investment profitable. For both the RPS and the base cases, we find the combined-cycle plant to be the marginal technology at the long-run equilibrium. In both cases, we find that the least profitable units to retire are located in Western New York.

Table 8 shows the long-run equilibrium level of prices and output for the base case. For reference, the corresponding short-run (2008) base case values are shown.

[20] The energy prices were estimated by GE-PSEC and we used the 2008 UCAP demand curve recently proposed by NYISO as the basis of the 2013 capacity market. To arrive at the 2013 demand curve, we increased the cost-based demand parameters in the demand curve by 3% per year to be consistent with the fact that energy prices are estimated in nominal currency values.

Table 8: Summary of Long-Run Equilibrium Base Case v. 2008

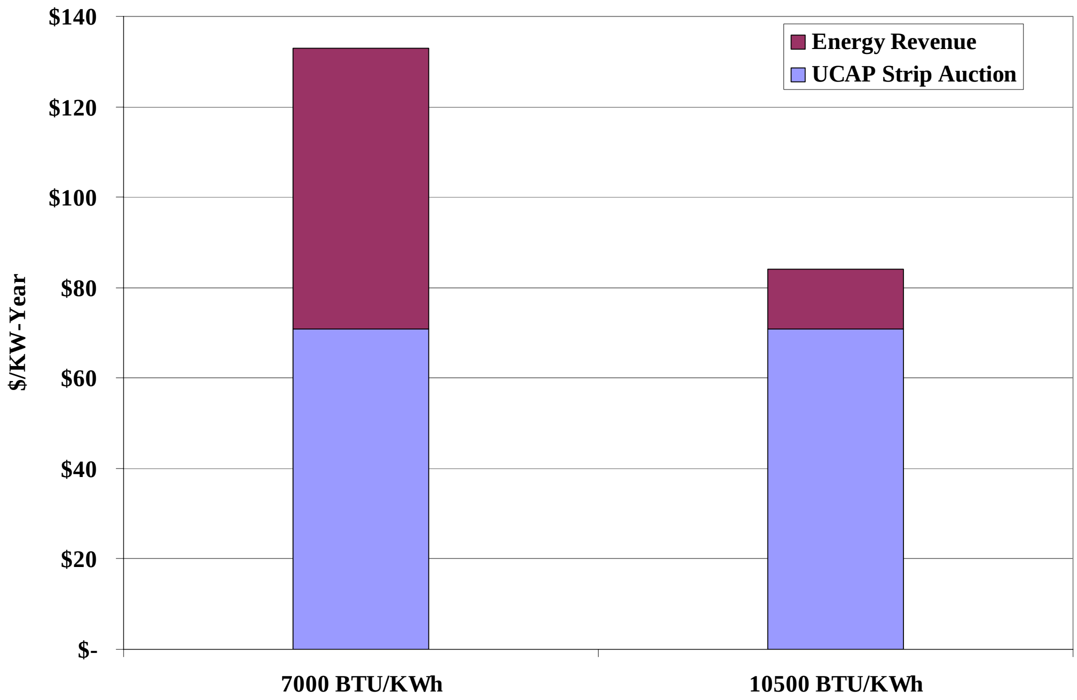
	2008	2013	Change	% Change
UCAP Prices				
Rest of State	$ 1.88	$ 5.90	$ 4.02	214.2%
LI	$ 12.87	$ 20.00	$ 7.13	55.4%
NYC	$ 10.75	$ 9.27	$ (1.48)	-13.7%
Weighted-Average Energy Price				
West	$ 40.37	$ 41.41	$ 1.04	2.6%
East	$ 46.23	$ 49.94	$ 3.71	8.0%
NYC	$ 44.91	$ 46.24	$ 1.33	3.0%

Note : For purposes of this Table, 2008 prices are expressed in 2013 dollar amounts based on an assumed 3% inflation rate. This permits a more direct intertemporal comparison.

As the table shows, the UCAP price for units located in the "Rest of State" category increase by more than 200%, from $1.88/kW-year to $5.90/kW-year. This is the result of load growing at a faster rate than capacity. The Energy prices also increase, although much slower than the capacity prices. The East prices increase the most (i.e., by 8 percent) due to higher shortage pricing in the East. The sharp decline in the NYC UCAP price is the result of price caps which cause the nominal UCAP prices to remain the same, resulting in a real price decline of almost 14%.

Figure 7 shows the net revenue for the combined-cycle (7000BTU/kWh heat rate) and gas turbine (10500 BTU/kWh heat rate) units for the long-run base case.

Figure 7: Net Revenue Base Case Long-Run Equilibrium



In the base case, the removal of the capacity provided sufficient net revenue that a combined-cycle (with a 7000BTU/kWh heat rate) is able to earn is approximately \$133/kW-year, an amount that would make entry just profitable. The net revenues for the less efficient gas turbine were less than \$85/kW-yr, less than the estimated break-even costs of \$106/kw-yr.

With the addition of RPS resources, the NYISO market will move further from long-run equilibrium and require more retirements than required in the base case to achieve a long-run equilibrium. We found a long-run RPS case by identifying retirements that would result in net revenue in line with entry costs for a new combined-cycle plant. In particular, we identified additional retirements in the RPS case totaling 1800 MW. These additional retirements resulted in higher energy and capacity prices and provide net revenues for units located in the East that are just sufficient to allow profitable entry.

Table 9 shows the results of the long-run RPS case compared to the 2008 RPS case.

Table 9: Summary of Long-Run Equilibrium RPS Case

	2008	2013	Change	% Change
UCAP Prices				
Rest of State	$ 1.54	$ 6.88	$ 5.33	345.9%
LI	$ 12.87	$ 21.00	$ 8.13	63.2%
NYC	$ 10.75	$ 9.27	$ (1.48)	-13.7%
Weighted-Average Energy Price				
West	$ 39.00	$ 38.89	$ (0.10)	-0.3%
East	$ 45.31	$ 47.52	$ 2.21	4.9%
NYC	$ 44.58	$ 44.64	$ 0.06	0.1%

Note : For purposes of this Table, 2008 prices are expressed in 2013 dollar amounts based on an assumed 3% inflation rate.

Table 9 shows that (with the exception of NYC) capacity prices increase significantly as a result of load outpacing the growth in generation. This increase is accelerated as the result of modeling a sharp increase in the number of retirements. Because the retirements are accelerated in the Rest of State, the change in capacity prices is particularly sharp in that location. It is also predictable that energy prices in the West decline because substantially more RPS resources come on line in the West between 2008 and 2013. Like in the base case, the NYC price decline in real terms as the result of price caps.

The combination of higher capacity and energy prices provide the necessary net revenues to make it close to profitable for a combined-cycle plant to enter, as shown in Figure 8.

Figure 8: Net Revenue -- RPS Long-Run Equilibrium

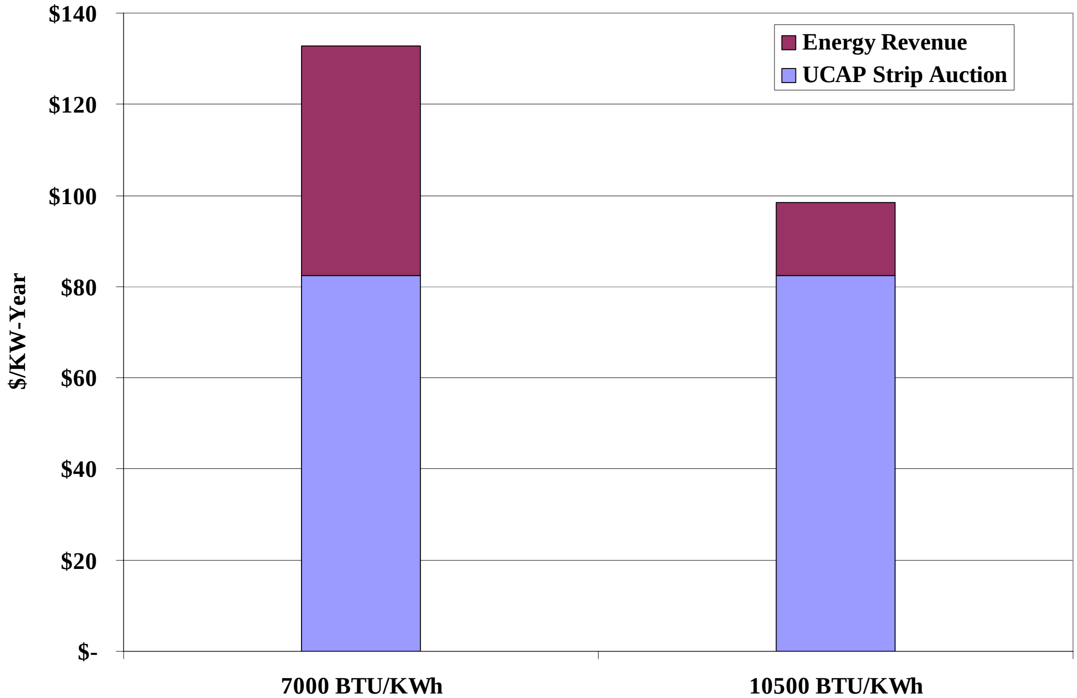


Figure 8 shows that net revenue for a 7000 BTU/kWh heat rate combined-cycle unit is sufficient to cover the $133/kW-year annualized costs. For the (10500 BTU/kWh heat rate) gas turbine, the net revenue is slightly less than its annualized cost.

Having identified a long-run equilibrium state with and without RPS resources, we then compare the results of these two cases. This comparison is more important because it shows the long-run impact of RPS. Table 10 shows a comparison between the long-run base case and the long-run RPS case.

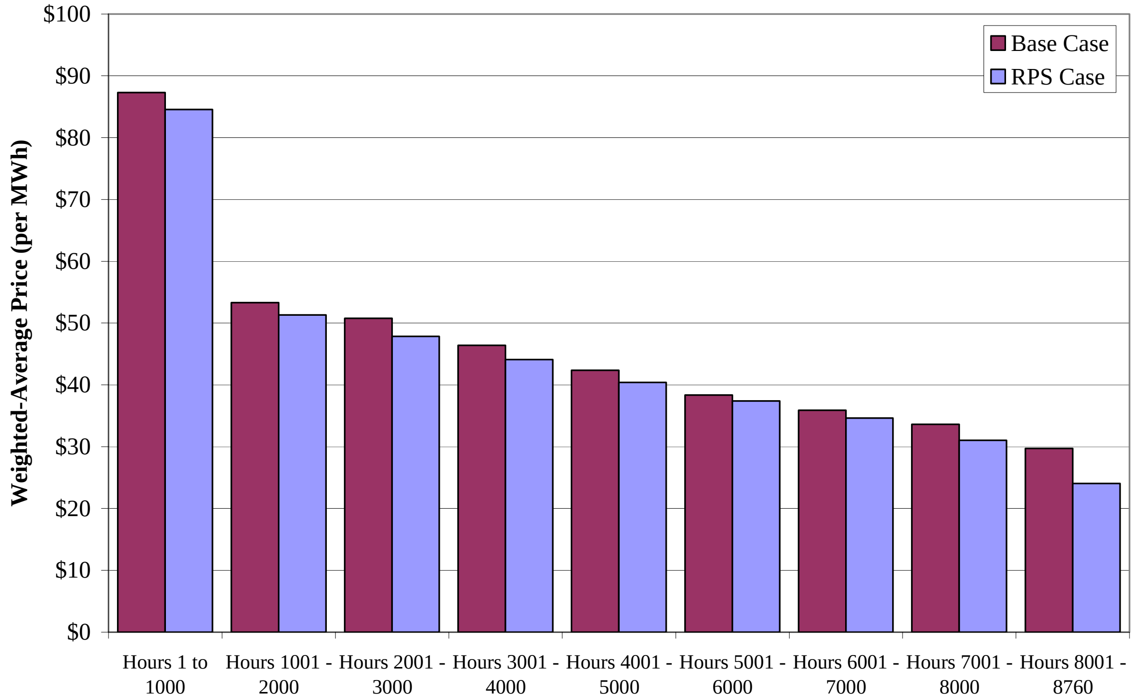
Table 10: Energy and Capacity Price - Long-Run Base Case vs. Long-Run RPS Case

	Base Case	RPS Case	Change	% Change
UCAP Prices				
Rest of State	$ 5.90	$ 6.88	$ 0.98	16.5%
LI	$ 20.00	$ 21.00	$ 1.00	5.0%
NYC	$ 9.27	$ 9.27	$ -	0.0%
Weighted-Average Energy Price				
West	$ 41.41	$ 38.89	$ (2.52)	-6.1%
East	$ 49.94	$ 47.52	$ (2.41)	-4.8%
NYC	$ 46.24	$ 44.64	$ (1.60)	-3.5%

When comparing the long-run base case and the long-run RPS cases, it is important to keep in mind that the RPS case contains additional capacity installed pursuant to RPS policies, but also additional retirements. Table 10 shows that the RPS additions result in a decrease in energy prices and an increase in capacity prices. This occurs because the load factor of the RPS units in the energy market is significantly higher than the capacity credit they receive in the capacity market. For example, the wind resources located in the West will have an average load factor of approximately 30 percent but receive a capacity credit of only 10 percent due to their intermittent and unpredictable nature. This results in a shift of revenues from the energy to the capacity market. The Table does not include the costs to achieve the RPS goals, which are discussed below.

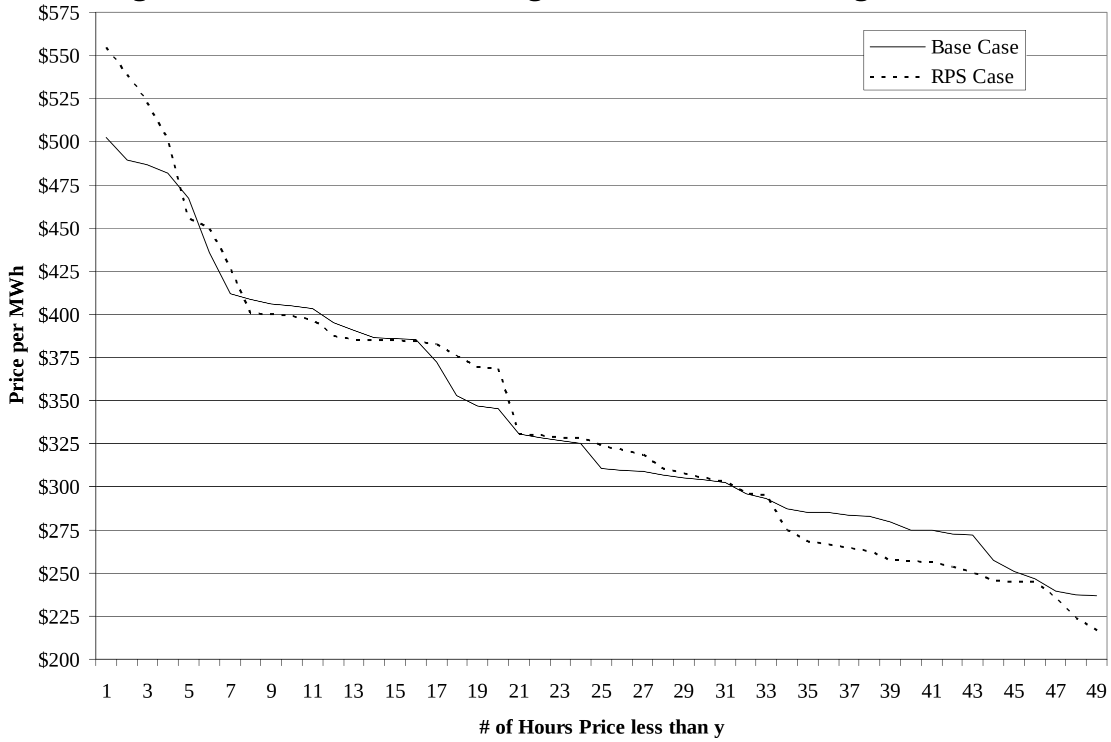
Energy prices decline most sharply in the West because most of the RPS resources are located in or are imported into the West and lower probabilities of state-wide shortage conditions. In the East and NYC, the RPS resources will tend to decrease prices as a result of low-cost power in the West. However, the additional retirements will result in higher prices during periods when West power is unavailable due to constraints. Overall, the new RPS units replace higher-cost existing units in the East and this will contribute to lower prices. The Table indicates that the overall effect is for prices to decline despite the retirements. A further evaluation of energy prices is shown in Figure 9.

Figure 9: Average Prices Long-Run RPS v. Base Case East Zone



As the figure shows, for every tranch of hours, the base case hours have average prices that are higher. For the highest-prices hours in Figure 10, the result is less clear.

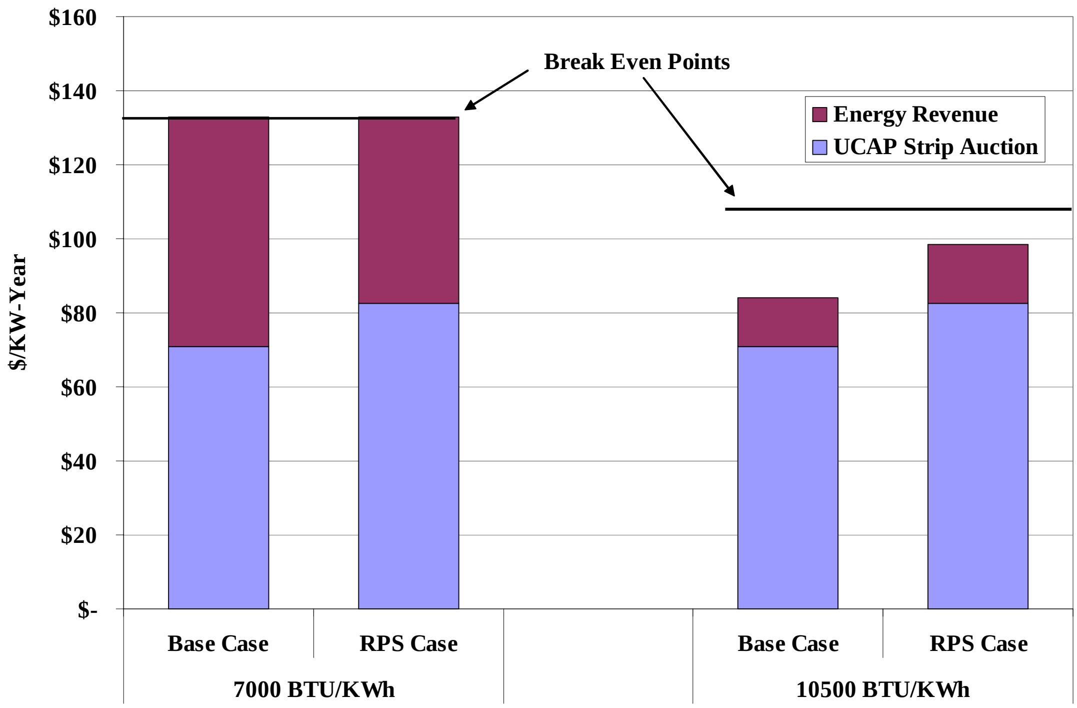
Figure 10: Price Duration Long-Run Base Case v. Long-Run RPS



The figure shows that base case and RPS prices track closely to one another, with the RPS prices ultimately falling below the base case prices.

While energy prices decline as a result of the RPS polices and the long-run retirements, the capacity prices increase, causing net revenues in the East to be comparable in the two cases. As shows Figure 11, the net revenue in the two cases is comparable.

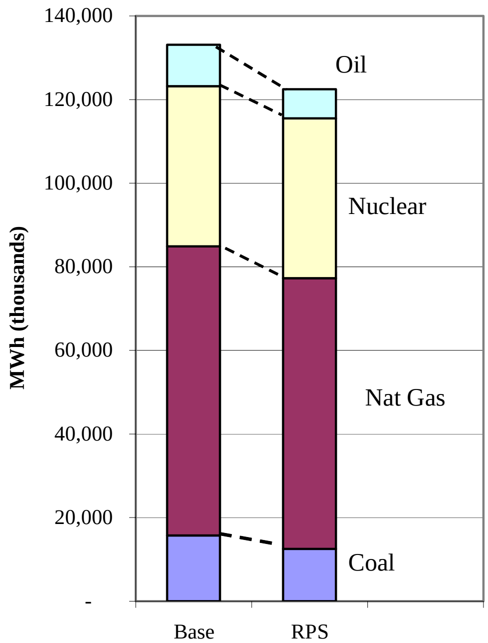
Figure 11: Long-Run Net Revenue -- Base Case v. RPS Case



The figure shows that the combined-cycle unit would be the marginal technology in both the base case and the RPS case. As discussed above, this figure also shows that the RPS investments shift the equilibrium revenues from the energy market to the capacity market.

We made further analysis of the long-run equilibrium by examining changes in output by fuel type. This analysis is summarized in Figure 12.

Figure 12: Changes in Output by Fuel Type
Long-Run Base Case v. Long-Run RPS Case



Fuel Type	Change (MWh)	Change (%)
COAL	(3,250,047)	-20.6%
NAT GAS	(4,403,880)	-6.4%
MISC RPS*	1,023,812	
NUCLEAR	-	0.0%
OIL	(2,963,168)	-29.8%
OTHER	(2,828)	-0.1%
WATER	-	0.0%
WIND	8,927,299	
CANADA IMPORTS**	2,760,208	118.7%
NON-CANADA IMPORTS**	(2,091,444)	-12.4%

Note: *MISC RPS includes new land-fill gas units, manure digestions, and biomass co-firing. **Import values shown are modeled flows rather than scheduled imports.

Like the short-run case, the fuel that experiences the largest displacement is natural gas. On a percentage basis, however, oil experiences the highest reduction, followed by coal. Oil and gas generation are displaced for the same reason as in the short-run case: because they are the marginal source of supply in a large share of the hours. However, the displacement of coal increases because the large share of the additional retirements caused by the RPS are forecasted to be coal-fired resources in the West.

The large installation of RPS-related hydro upgrades in Canada results in large shifts in imports, with Canadian imports increasing at the expense of other imports. In addition to changes by fuel type, we quantify the changes by zone. This analysis is shown in Table 11.

Table 11: Zonal Changes in Production

Zone	Base Case	RPS Case Total	RPS Output	Change	Change %
West Native	74,042,770	75,808,301	7,080,703	1,765,531	2.4%
West Imports	19,159,725	19,828,489	2,760,208	668,764	3.5%
West Total	93,202,494	95,636,790	9,840,911	2,434,296	2.6%
East	38,667,325	37,838,891	516,854	(828,435)	-2.1%
NYC	37,544,523	35,670,403	-	(1,874,120)	-5.0%
Long Island	14,986,176	15,254,386	2,353,554	268,211	1.8%
Total	184,400,518	184,400,469	12,711,319		

As the Table shows, the output in the West and the imports from Canada increase in the RPS case. This occurs because these are the locations where the new RPS resources are added. The output in the East and NYC declines. In Long Island, an increase in RPS output offsets a decrease in existing units' output.

Finally, we examine changes in long-run load payments as a result of RPS policy. We compare the long-run base case with the long-run RPS case for both the capacity market and the energy market. Table 12 summarizes the difference in capacity payments between the long-run base case and the long-run RPS case.

Table 12: Long-Run Capacity Payments -- Base Case v RPS Case

		NYCA	NYC	LI	Total
Base Case					
Summer 2013					
	Price (kW-Mo)	$7.30	$11.42	$21.00	
	UCAP Purchase (MW)	25,428	9,750	5,222	
	Revenue ($million)	$1,114	$668	$658	$2,440
Winter 2013					
	Price (kW-Mo)	$4.50	$7.12	$19.00	
	UCAP Purchase (MW)	26,650	10,500	5,350	
	Revenue ($million)	$720	$449	$610	$1,778
Total Base Case 2013		$1,833	$1,117	$1,268	$4,218
RPS Case		NYCA	NYC	LI	Total
Summer 2013					
	Price (kW-Mo)	$8.40	$11.42	$21.00	
	UCAP Purchase (MW)	25,124	9,750	5,226	
	Revenue ($million)	$1,266	$668	$658	$2,593
Winter 2013					
	Price (kW-Mo)	$5.35	$7.12	$21.00	
	UCAP Purchase (MW)	25,950	10,500	5,350	
	Revenue ($million)	$833	$449	$674	$1,956
Total RPS 2013		$2,099	$1,117	$1,333	$4,548
Revenue Change from RPS		$266	$0	$65	$331

Consistent with the analysis above showing substantial increases in capacity payments as the results of RPS, the Table shows capacity payments increase by $331 million. This increase is offset by a reduction in energy payments, as shown in Table 13.

Table 13: Summary of Long-Run Load Payments

Energy Payments in Long-Run Base Case	$8,342
Capacity Payments in Long-Run Base Case	$4,218
Total Load Payments in Long Run Base Case	$12,560
Energy Payments in Long Run RPS Case	$7,966
Capacity Payments in Long-Run RPS Case	$4,548
Total Load Payments in Long Run Base Case	$12,514
Change in Energy and Capacity Payments	-$46
Annual REC Payment in 2013	$220
Net Change in Annual Load Payments	$174

Note : Values in millions.

As the Table shows, load payments for energy and capacity decline by $46 million. When considering the $220 million in annual costs for achieving RPS, the net impact is a cost increase of $174 million.

IV. Renewable Energy Credit Mechanism

A. General

In this section, we provide a qualitative evaluation of the mechanism by which new RPS resources will be procured. The Commission's proposed rule calls for NYSERDA to determine a mechanism for procuring the necessary RPS projects to meet the RPS production goals. The discussion surrounding the mechanism has focused on alternatives auction methods to be administered by NYSERDA. Successful bidders would earn Renewable Energy Credits ("RECs") for energy produced from new renewable energy resources. The key difference among the alternative mechanisms is whether the REC should be fixed on a MWh basis or whether it should vary with the energy price at the location of the resource. The decision to adopt a fixed or variable REC mechanism has important market impacts.

The fixed REC regime pays the RPS resource a constant REC for each MWh of output. The resource would earn additional revenue to the extent it also sells in the other NYISO markets. Therefore, its total revenue in every hour is the sum of market revenues plus the fixed REC. Since the other market revenues are variable, hourly revenues would be variable under a fixed REC mechanism. Under the fixed REC regime, eligible RPS suppliers would compete by making fixed REC offers.

The variable REC regime pays the RPS resource a REC that varies based on the revenue earned in the NYISO energy market – the REC is the difference between hourly revenues earned in the NYISO energy markets each hour less the fixed hourly guarantee. For example, if the fixed price is $60 per MWh and the LBMP is $35, the supplier would receive a REC in that hour of $25 per MWh. This has been referred to as a “contract-for-differences” (CFD) although it differs from a typical CFD because it is linked to the actual output of the unit. Under the variable REC (or CFD regime), eligible resources would compete by offering a fixed total hourly payment where the REC varies to make up the difference between the hourly revenue earned in NYISO markets and the fixed hourly guarantee.

B. Evaluation of the Fixed REC versus Variable REC Methods

The essential difference between the fixed REC mechanism and the variable REC mechanism is that the fix REC mechanism has a constant REC but hourly revenues vary while the variable REC has constant hourly revenue but the REC varies. The mechanism that is selected can have important implications for market efficiency. To evaluate the economic efficiency of the alternative methods, we employ three main criteria. The method should:

1. Result in bidding behavior that would contribute to efficient dispatch;
2. Provide efficient investment decisions; and
3. Allocate the market risk to the parties in the best position to manage it.

Based on these criteria, we conclude that the fixed REC approach will best satisfy these efficiency objects. With respect to efficient dispatch, the fixed REC mechanism is superior to the variable REC mechanism because energy market bidding by RPS resources under a fixed REC mechanism will be more closely correlated with the resources’ operating costs. This is true because at sufficiently low prices, a resource under a fix REC mechanism will bid to avoid dispatch while under a variable REC, the resource will bid to be dispatched at any price.

In particular, under a fixed REC mechanism, a resource will bid to be dispatched only when the energy price is greater than the operating cost plus the fixed REC. In contrast, under a variable REC, the resource is guaranteed hourly revenue that will always be above its operating cost. Hence, under a variable REC the resource will bid without regard to the relationship between operating cost and the energy price. This will tend to cause the dispatch to depart from the most efficient use of committed resources.

The fixed REC and variable REC also differ in important ways regarding incentives for efficient location and technology decisions. The fixed REC can more efficiently reflect the underlying value of capacity and energy at various locations and the underlying value of energy delivered at different times. This contributes to incentives to install resources that are most in need. If renewable resources compete to provide RPS service through fixed REC offers (with the lowest bid REC being selected), resources in locations that earn high capacity and energy payments can bid a lower REC than resources in areas where capacity payments are low because the overall economics of the project improves with the higher energy and capacity prices earned. Hence, even if the cost to install a resource is higher in a high-valued location than in a location where it is less costly to install, the resource in the higher-valued location can remain competitive because of higher market revenues despite its higher installed cost. Therefore, the fixed REC mechanism will efficiently reflect how both investment costs and the underlying energy and capacity values vary by location.

In addition to the location of resources, the temporal aspects of the resources can be important. Some resources are more controllable and, therefore, can deliver higher quantities of power during peak periods when it is most valuable. Other resources are more intermittent and, therefore, tend to produce energy that has lower overall value to the system. Since the fixed REC would be additive to the NYISO market revenue, this alternative would more efficiently reveal the higher value of renewable resources that are relatively more controllable.

The CFD mechanism, on the other hand, is based on a per-MWh total payment and would favor resources in locations where installed costs are low without regard to the benefit of locating where capacity is needed. While a CFD mechanism may lower overall installation costs, it will not necessarily lead to maximal system-wide benefit.

Finally, the fixed REC mechanism allocates risk more efficiently than a variable REC mechanism. Under a fixed REC mechanism, the entrepreneur would face the risk of correctly estimating the costs and revenues of its project based on the proposed resource technology and location. This will induce the owner to manage its resource so that it is available when it is most likely to earn the highest revenues, thereby reducing the price risk. Under the variable REC, a resource owner does not face the risk of price changes because its payment is based on a fixed hourly rate. Accordingly, the owner does not need to manage the risk of prices changes.

Appendix

RPS Resources Assumed to be in Service in 2008 and 2013

ENERGY SOURCE BLOCK	Location	Market Index	2008 Installed Capacity (MW)	2013 Installed Capacity (MW)
Wind Farms NY-z1b1	NY Zone 1	NY Zone 1	50	50
Wind Farms NY-z1b2	NY Zone 1	NY Zone 1	450	450
Wind Farms NY-z1b3	NY Zone 1	NY Zone 1	840	1400
Wind Farms NY-z2b2	NY Zone 2	NY Zone 2	50	50
Wind Farms NY-z2b3	NY Zone 2	NY Zone 2	50	50
Wind Clusters NY-z1b1	NY Zone 1	NY Zone 1	20	20
Wind Clusters NY-z1b2	NY Zone 1	NY Zone 1	0	150
Wind Clusters NY-z1b3	NY Zone 1	NY Zone 1	0	0
Wind Clusters NY-z3b2	NY Zone 3	NY Zone 3	15	15
Wind Clusters NY-z3b3	NY Zone 3	NY Zone 3	0	15
Off-Shore Wind Lakes NY-z1	NY Zone 1	NY Zone 1	0	0
Off-Shore Wind LI NY-z3	NY Zone 3	NY Zone 3	0	579
Wind Farms Quebec	Quebec	NY Zone 1	0	0
Wind Farms Ontario	Ontario	NY Zone 1	0	0
Wind Farms PJM b1	PJM	NY Zone 1	0	250
Manure Digestion NY-z1	NY Zone 1	NY Zone 1	0	0
Manure Digestion NY-z2	NY Zone 2	NY Zone 2	0	2
Biomass Co-firing w/Coal NY-z1 b1	NY Zone 1	NY Zone 1	23	38
Biomass Co-firing w/Coal NY-z1 b2	NY Zone 1	NY Zone 1	38	63
Biomass Co-firing w/Coal NY-z1 b3	NY Zone 1	NY Zone 1	0	137
Biomass Co-firing w/Coal NY-z2	NY Zone 2	NY Zone 2	34	56
Biomass Co-firing w/Coal Ontario	Ontario	NY Zone 1	0	0
Biomass Co-firing w/Coal PJM	PJM	NY Zone 1	0	0
Biomass Gasification NY z1 b1	NY Zone 1	NY Zone 1	0	0
Biomass Gasification NY z1 b2	NY Zone 1	NY Zone 1	0	0
Biomass Gasification NY z1 b3	NY Zone 1	NY Zone 1	0	0
Biomass Gasification NY z1 b4	NY Zone 1	NY Zone 1	0	0
Biomass Gasification NY z2 b1	NY Zone 2	NY Zone 2	0	0
Biomass Gasification NY z2 b2	NY Zone 2	NY Zone 2	0	0
Biomass Gasification NY z2 b3	NY Zone 2	NY Zone 2	0	0
New Biomass CHP NY z1 2007	NY Zone 1	NY Zone 1	0	0
New Biomass CHP NY z1 2012	NY Zone 1	NY Zone 1	0	0
New Low-Impact Hydro NY z1	NY Zone 1	NY Zone 1	0	0
New Low-Impact Hydro NY z2	NY Zone 2	NY Zone 2	0	0
New Low-Impact Hydro NY z3	NY Zone 3	NY Zone 3	0	0
New Low-Impact Hydro Quebec	Quebec	NY Zone 1	0	0
New Low-Impact Hydro Ontario	Ontario	NY Zone 1	0	0
Hydro Upgrades NY z1	NY Zone 1	NY Zone 1	0	0
Hydro Upgrades NY z2	NY Zone 2	NY Zone 2	0	0
Hydro Upgrades Quebec	Quebec	NY Zone 1	180	300
Hydro Upgrades Ontario	Ontario	NY Zone 1	347	800
Very Small New Hydro NY z1	NY Zone 1	NY Zone 1	0	0
Very Small New Hydro NY z2	NY Zone 2	NY Zone 2	0	0
Very Small New Hydro NY z3	NY Zone 3	NY Zone 3	0	0
Landfill Gas IC Engines NY z1	NY Zone 1	NY Zone 1	75	88
Landfill Gas IC Engines NY z2	NY Zone 2	NY Zone 2	24	26
Landfill Gas IC Engines NY z3	NY Zone 3	NY Zone 3	3	3
Landfill Gas Microturbines NY z1	NY Zone 1	NY Zone 1	0	3
Landfill Gas Microturbines NY z2	NY Zone 2	NY Zone 2	0	1
Landfill Gas Microturbines NY z3	NY Zone 3	NY Zone 3	0	0
Eligible Hydro Maintenance NY z1	NY Zone 1	NY Zone 1	0	0
Total			2200	4546