5 Operational Analysis

The purpose of the operational analysis is to evaluate the operational feasibility of integrating large amounts of variable renewable generation into the study area footprint. A range of renewable penetrations was considered as well as various system sensitivities such as fuel prices, Carbon price impacts, and transmission expansion. The analysis was performed using the GE Multi Area Production Simulation program, MAPS, which performs a day-ahead unit commitment and an hourly dispatch recognizing transmission constraints within the system and individual unit operating characteristics. Details of the model are included in Appendix C. Except where noted, day-ahead wind power forecasts were used in the commitment process. As a by-product of the analysis, the production cost and emission impact of wind power was also determined. While that information is useful and of interest to many, it is important to recognize that it is not the intent of this study to economically justify wind generation. This study seeks to determine the overall feasibility of incorporating large amounts of wind generation into the operation of ISO-NE, what operational challenges might arise, and what changes might be required to facilitate this integration.

5.1 Assumptions

The operational analysis for NEWIS was simulated for a year to approximate the year 2020. The underlying NEWIS base database, which includes ISO New England, New York ISO, PJM Mid-Atlantic and the Maritimes were modeled in detail based on sources from 2009 CELT report for ISO New England and Velocity Suite of Ventyx Vintage 2009 for the rest. Figure 5–1 below outlines the system modeled.

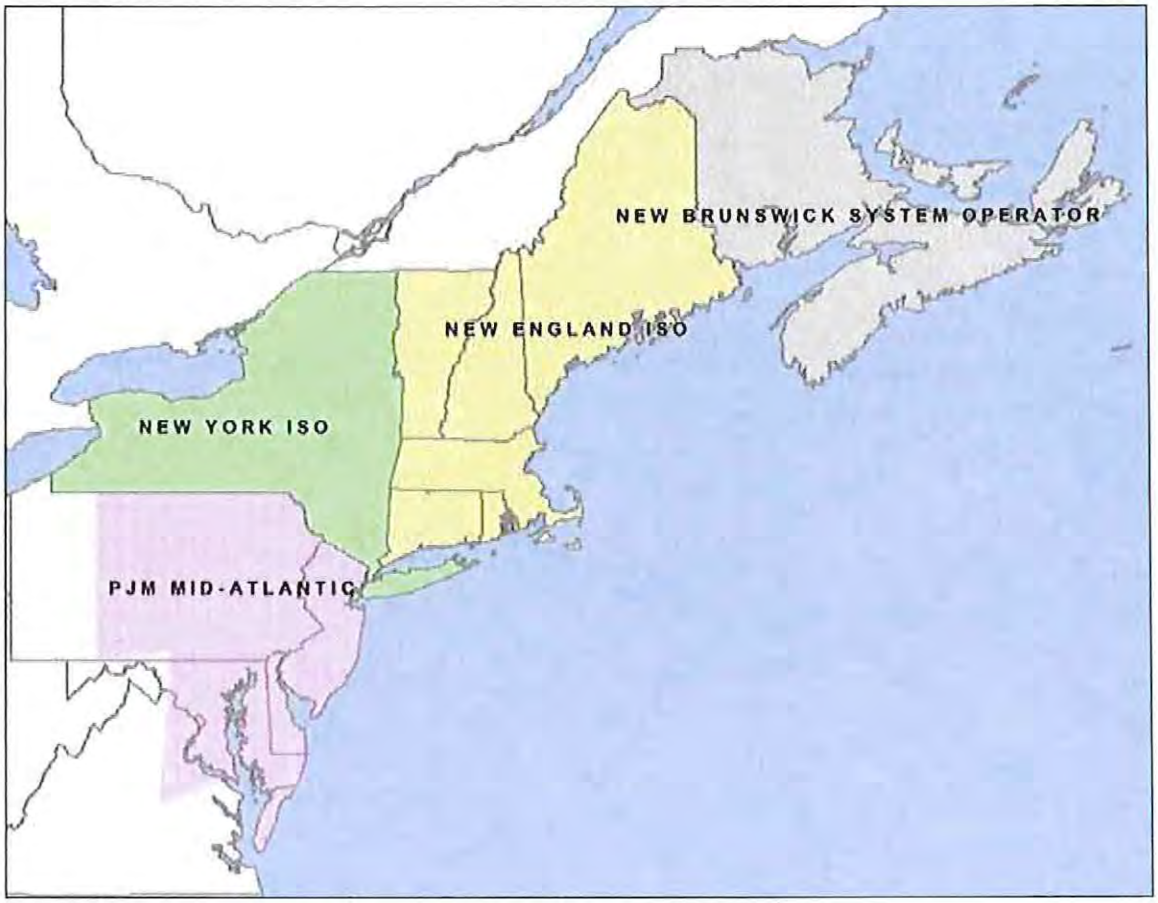


Figure 5–1 NEWIS System map

Transfers between HQ, Ontario, and NEWIS systems were represented as proxy generators as follows:

- HQ Phase 2 was modeled as a 1,600 MW generator with increasing heat rates
- HQ model duplicated for NYISO
- Ontario to NY is modeled as a 2000 MW generator with increasing cost block generator (Calibrated based on 2006 actual imports)

Areas modeled within the NEWIS system are entities that represent load and are based on the regions used in Ventyx's models. These load areas are derived through extensive analysis of FERC 715 data and Multiregional Modeling Working Groups (MMWGs) in the Eastern interconnect.

Load was extrapolated out to approximately 2020 by increasing the peak and keeping the same load factor of the yearly shape (2004, 2005, and 2006). Peak Forecasts for different regions are based on sources listed in Table 5–1.

Table 5–1 Peak Load Forecast and Source

Region	Peak (MW)	Source
ISO-NE	31,500	2009 CELT report
NYISO	36,137	2009 Load & Capacity Data (Gold Book)
PJM Mid-Atlantic	70,342	PJM Load Forecast Report January 2009
Maritimes	6,237	2008 NERC ES&D

The generator data includes full and part load heat rates, emission rates, minimum operating points and other operating characteristics appropriate to its technology, year built and size. Steady state incremental heat rates and emission rates were modeled. Ten-year historical monthly energies were used for the hydro generation. Additional thermal capacity was added to the existing generation to cover the load growth through 2020; expansion units for ISO-NE were based on the Forward Capacity Market results. Other regions included units under construction with status as of Jan-2010 to be installed in the near future. Additional combined cycle and peaking generation was added to maintain regional reserve margins requirements. The total additions are as follows:

- Maritimes - 1,000 MW
- NYISO – 150 MW
- PJM – 11,300 MW

The same expansion plan was used for all scenarios. As wind generation was added, no thermal capacity was removed.

The key fuel assumptions are listed in Table 5–2. They are based on EIA Annual Energy Outlook, April 2009.

Table 5–2 Regional Fuel price

Region	Coal ($/mmBtu)	Natural Gas ($/mmBtu)	Residual Oil ($/mmBtu)	Distillate Oil ($/mmBtu)
ISO-NE	2.86	7.63	15.77	21.36
NYISO	2.25	7.28	15.58	21.13
PJM Mid-Atlantic	2.10	7.40	15.82	21.07
Maritimes	2.86	7.63	15.77	21.36

Another key assumption is that no carbon cost has been assumed. Hurdle rates between ISO-NE, NYISO, PJM Mid-Atlantic and Maritimes were modeled at $10/MWh for commitment and $6/MWh for dispatch; separate hurdle rates were modeled for AC and DC systems. Hurdle rates represent transmission tariffs and market inefficiencies between control areas. Spinning reserve modeled for ISO-NE is synchronized 10 min spin, 750 MW during weekdays between 0700hrs to 2300hrs and 650 MW during weekdays between 2300hrs to 0700hrs and all hours during weekends. 10-minute spinning reserve was modeled in the analysis. It was verified that a sufficient amount of 10-minute non-spinning reserve was available in the simulation. 30-minute non-spinning reserve was not modeled. Wind units were modeled with a dispatch cost of $10/MWh so that nothing below this value would be displaced. In the production simulation results no variable cost was assumed for the wind generation. Capital costs were not included and dispatchable demand (i.e. Demand Response) units were modeled to meet load when price reaches $500/MWh or above. The outage schedule, for thermal generators, was held constant for all simulations.

5.2 Annual Operational Impacts

A variety of metrics are presented to address the question, "What happens to the operation of the system with high levels of intermittent wind generation?" Some of these metrics include annual generation displacement by type, system operating costs, utilization of pumped storage hydro, and locational marginal price impacts.

Running out of ramp down capability and curtailment are also important metrics to analyze the operational impacts of wind. Both signify minimum generation issues. Addressing minimum generation issues presumably means recommitting the system with more expensive units. For example, a coal unit may need to be turned off and gas turbines turned on to achieve the flexibility necessary.

5.2.1 ***Best Sites Onshore***

The following section looks at the impacts of increasing wind penetration on the ISO-NE system. All results presented are for the Best Sites Onshore scenario with full transmission. "State of the art" (S-o-A) wind forecast was used. A subset of results for the other scenarios will be presented in Appendix C of the report.

Parameters that are normalized based on a MWh of ISO-NE wind generation, use the net wind generation. The net wind generation is calculated by subtracting the additional exports for each scenario, as compared to the No Wind Scenario, from the total ISO-NE wind energy. This is done to eliminate any benefit to ISO-NE from wind energy that is exported to the surrounding regions.

Figure 5–2 shows the normalized average seasonal daily output of a randomly selected onshore wind plant. Not surprisingly, the summer has the lowest nameplate output. The winter has some hours where the typical output nears 45%.

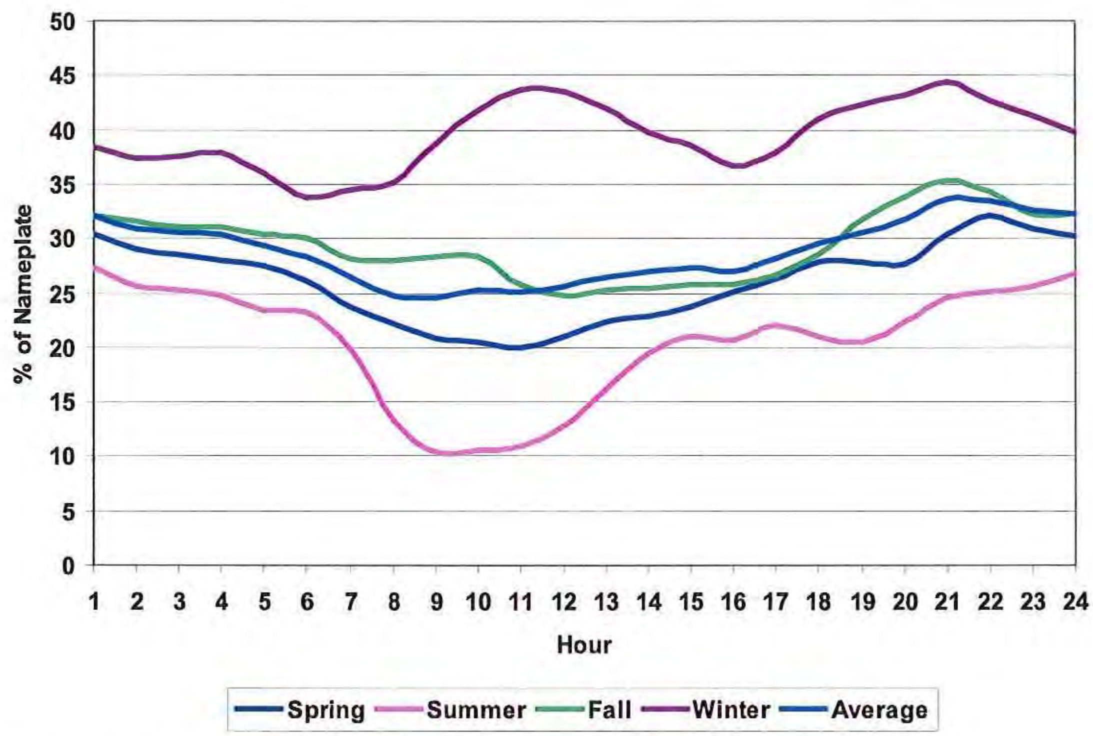


Figure 5–2 Typical seasonal average onshore plant daily pattern

Figure 5–3 shows the total generation by type for ISO-NE with increasing wind penetration. The bulk of the energy that is displaced by the wind generation as compared to the No Wind Scenario is coming from the Combined Cycle (CC) units. As the penetration increased, the steam coal (St-Coal) generation displacement increased. There are also slight variations in imports from Hydro Quebec (HQ imports) and imports/exports (Imp_Exp) from the other neighboring regions. There is an increase in imports into ISO-NE at 14% penetration. At the lower penetrations (2.5%, 9%) the surrounding regions were not built to the same penetration as ISO-NE: only existing wind was modeled. At 14% penetration, PJM and NY were built out to that penetration. With the addition of the wind they were able to export more generation to ISO-NE. This is also seen in the 20% penetration case. The Imp_Exp decreases at 24% penetration as compared to 20% penetration. The neighboring systems were kept at 20% penetration and the imports are being displaced by wind generation.

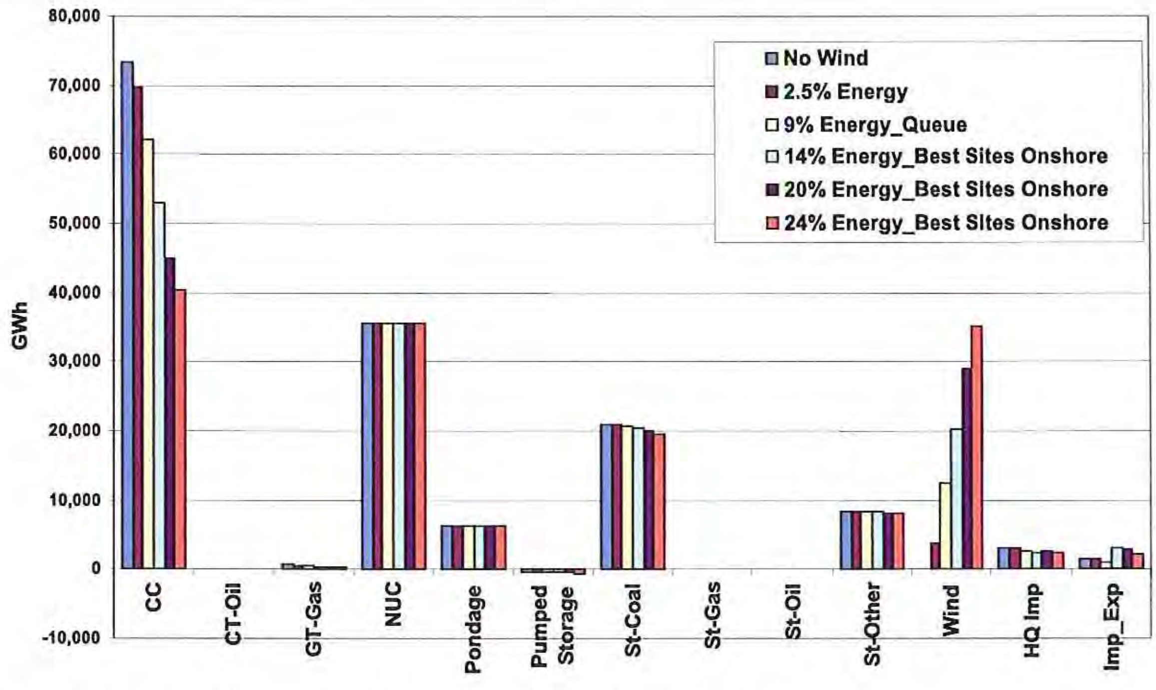


Figure 5–3 ISO-NE generation by type, S-o-A forecast, Best Sites Onshore

Figure 5–4 zooms in on the annual coal generation in Figure 5–3. At the lower penetrations, the amount of coal displacement is less than 1%. From the 14% to 24% penetration, the coal generation is reduced about 460 GWh to 1,350 GWh relative to the No Wind Scenario: a 2.2% to 6.5% reduction. Figure 5–5 shows the total ISO-NE St-Coal generation on a monthly basis. Most of the coal displacement occurs in the spring and fall months. The 24% penetration scenario has slightly more coal energy in April than the 20% case. Although this may seem counterintuitive, it is the result of the fact that the 24% penetration scenario uses the 8 GW transmission overlay, while the 20% penetration scenario uses the 4 GW transmission overlay. Although transmission is not a major issue overall, the expanded transmission in the 8 GW overlay allows more flow and hence more generation by St-Coal in April.

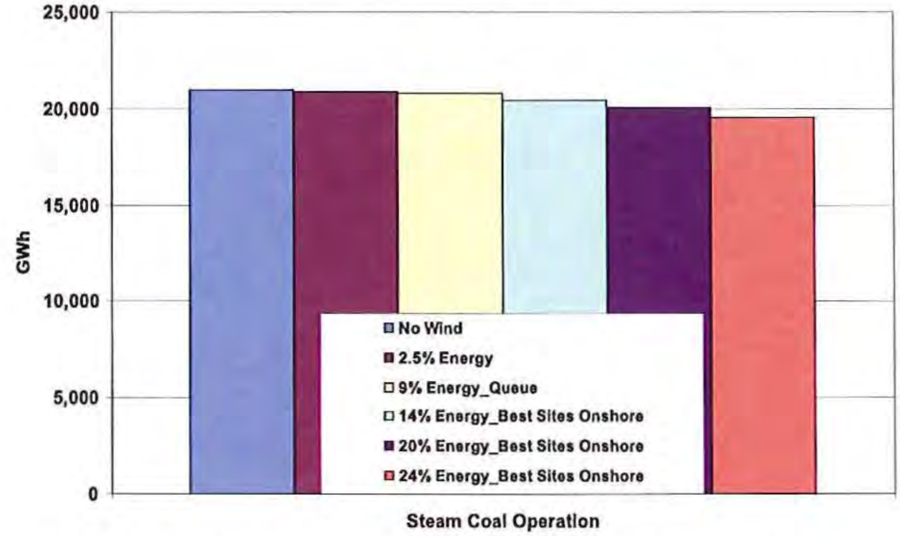


Figure 5–4 ISO-NE annual coal production S-o-A forecast, Best Sites Onshore

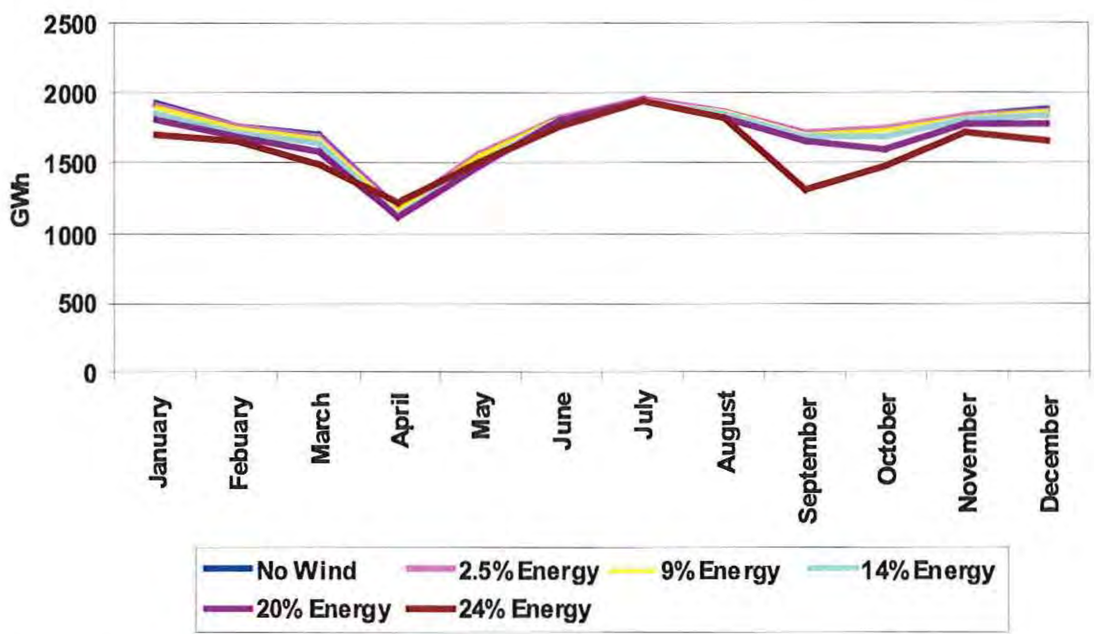


Figure 5–5 ISO-NE monthly coal production S-o-A forecast, Best Sites Onshore

As penetration of wind increases, the number of starts and energy produced by quick-start units decreases. The decline in starts is likely due to the fact that the conventional generation portfolio for this study was designed to meet ISO-NE requirements in year 2020 without wind generation. None of this conventional generation was eliminated as wind power was added to the system and therefore the quick start energy is being displaced by the wind. For example, Figure 5–6 show total number of starts the quick start units had for the increasing penetrations of the Best Sites Onshore case. The results compare using a perfect and S-o-A wind forecast. The number of starts decreases with increasing penetration using a perfect forecast. At the same time, although overall decreasing, using a S-o-A forecast, more starts occur as compared to the result with perfect forecast, due to forecast error. The delta starts between the perfect and S-o-A forecast increases with higher wind penetration. This is consistent with the analysis in section 4 where increased wind penetrations using state-of-the-art wind power forecasts cause increases in the amount of TMNSR that must be carried.

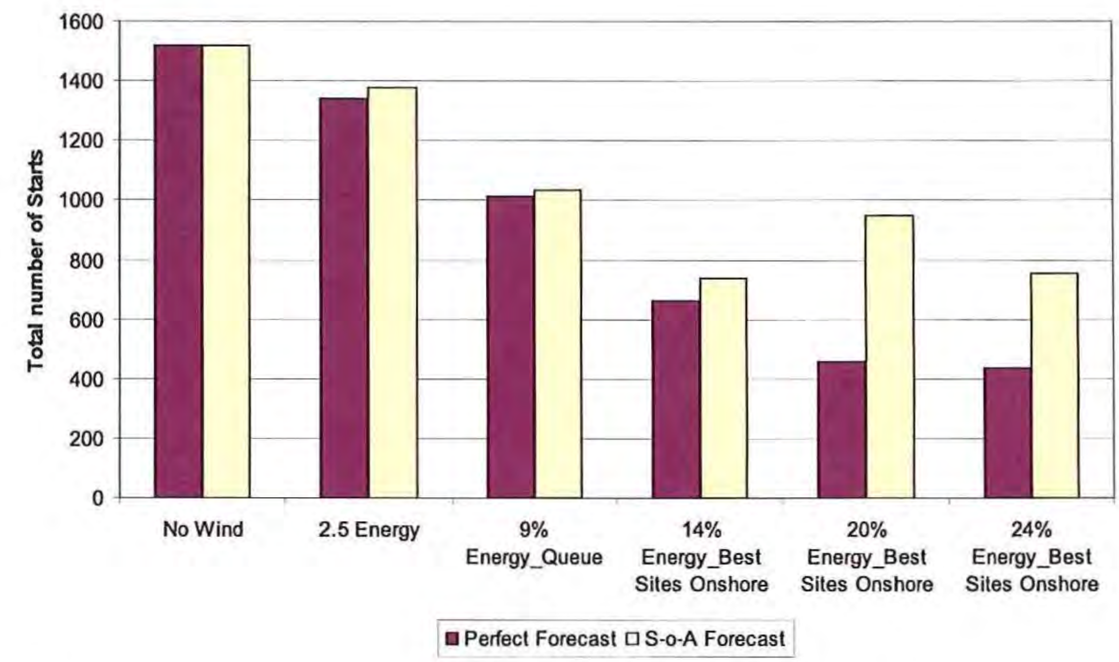


Figure 5–6 Total Annual Starts for Quick-Start Units, Best Sites Onshore, Perfect vs. S-o-A forecast

Figure 5–7 shows the hourly duration curve for the pumped storage hydro operation in ISO-NE for the No Wind and various penetration levels of wind. The operation is less for the 2.5% Energy, 9% Energy_Queue, and 14% Energy_Best Sites Onshore scenarios and increases in the 20% Energy_Best Sites Onshore and 24% Energy_Best Sites Onshore compared to the No Wind scenario. All the scenarios contain some offshore wind. Offshore typically has higher capacity factors than onshore wind and provides more energy during the peak hours. This creates less of on-peak/off-peak price differential. As the penetration increases, the overall percentage of offshore wind decreases creating more of an on-peak/off-peak price differential, therefore increasing pumped storage operation.

This is a similar result seen in the recent Western Wind and Solar Integration Study[70], the NY[71] wind integration study and the Irish All-Island report[72]. It is often believed that additional storage is necessary for large-scale wind integration. Minute-to-Minute type storage is useful to address regulation concerns, but additional large-scale economic arbitrage type storage, like Pumped storage Hydro (PSH) has been shown to not be required. As shown in these studies, as the wind power penetration increases, spot prices tend to decrease, particularly during high priced peak hours. The off-peak hours remain relatively the same. Therefore, the peak and off-peak price spread shrinks and no longer has sufficient range for economic storage operation. The price spread decreases substantially, which reduces the economic driver for energy storage due to price arbitrage. As wind penetration increases, a higher on-peak/off-peak price differential is created, therefore increasing PSH operation. Similar results will be seen later in the chapter for the 20% Energy scenario comparison.

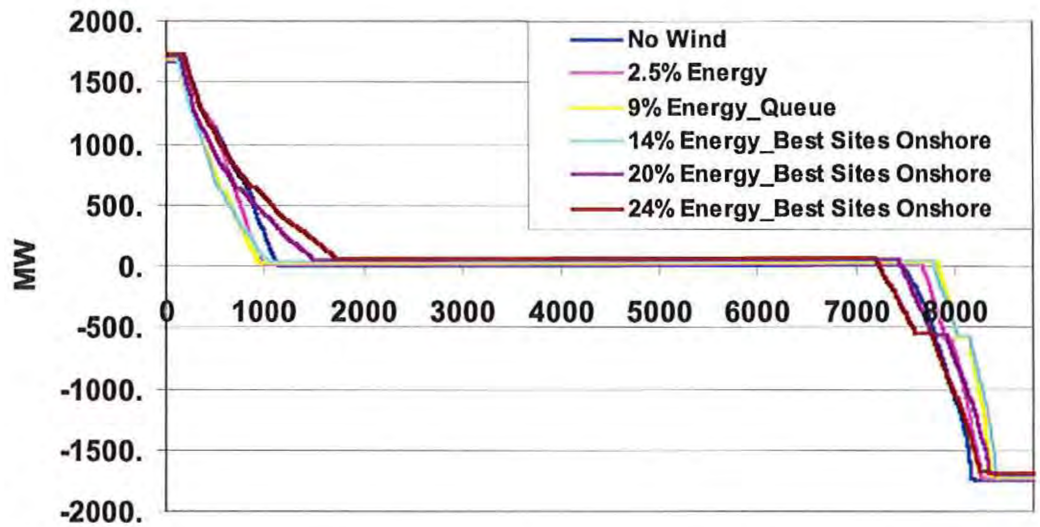


Figure 5–7 ISO-NE pumped storage operation S-o-A forecast, Best Sites Onshore

Figure 5–8 shows the reduction in total emissions as the wind penetration increases. As expected: as the wind penetration increases and conventional generation is displaced, the overall emissions go down. With 24% wind penetration, NOx is reduced by approximately

[70] http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf

[71] http://www.nyserda.org/publications/wind_integration_report.pdf

[72] http://www.dcenr.gov.ie/Energy/North-South+Co-operation+in+the+Energy+Sector/All+Island+Electricity+Grid+Study.htm

7,000 tons or 30%, SOx is reduced by approximately 8,500 tons or 8%, and CO2 is reduced by 15 million tons or 30%. As stated in the initial assumptions steady state emission rates were modeled at multiple operating levels on the generators. When transitioning from one level to another the emissions may be higher until the systems can be properly balanced. While this may cause slight temporary increases at some plants the effect should be minimal at a system level.

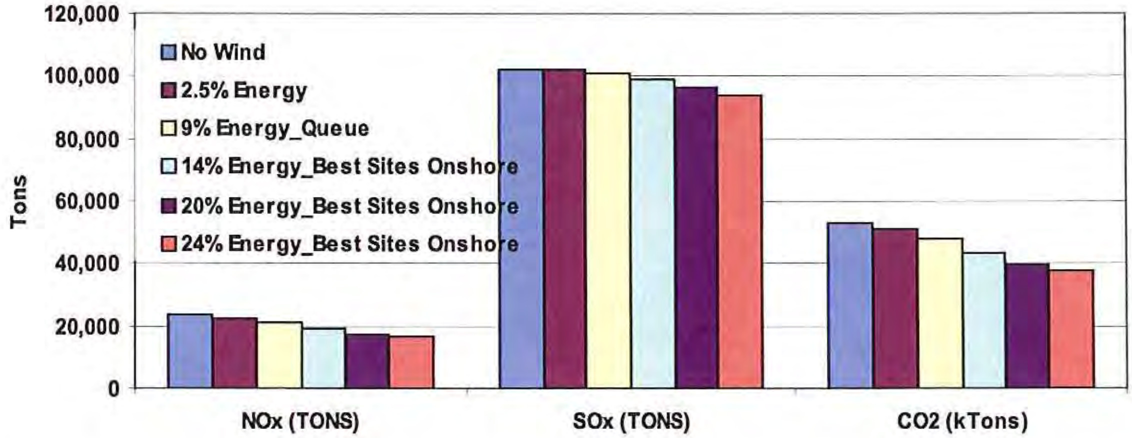


Figure 5–8 ISO-NE total emissions S-o-A forecast, Best Sites Onshore

Figure 5–9 shows the ISO-NE emission reduction per MWh of wind generation. This is calculated for each scenario by dividing total emission reduction relative to the No Wind Scenario by the total ISO-NE wind generation produced in that scenario. The net wind was used to calculate the emission reduction.

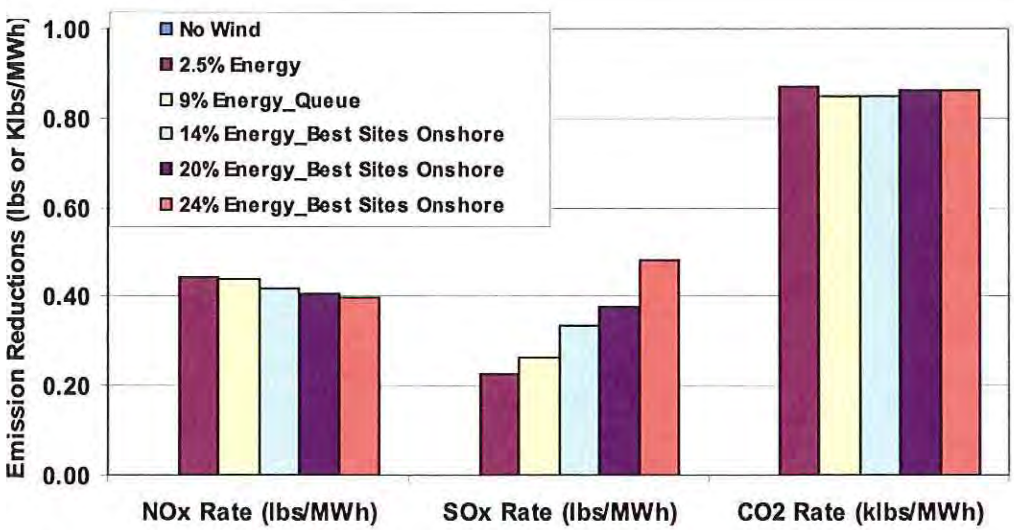


Figure 5–9 ISO-NE total emission reduction per MWh of wind generation S-o-A forecast, Best Sites Onshore

An important measure is the hourly marginal cost of energy, or spot price. In a deregulated market, like ISO-NE, this is the price paid for energy each hour. When transmission constraints are present, these values will vary across the system for any given hour, but they can be weighted by the hourly load in the constrained areas to produce an "effective" locational marginal price (LMP) for each area.

Figure 5–10 shows the annual average load weighted ISO-NE locational marginal price (LMP) for the increasing wind penetration scenarios. The average LMP for the No Wind Scenario was approximately $61/MWh. The overall reduction of LMP by introducing increasing wind penetration into ISO-NE ranged from $1/MWh at 2.5% penetration to $9/MWh at 24% penetration.

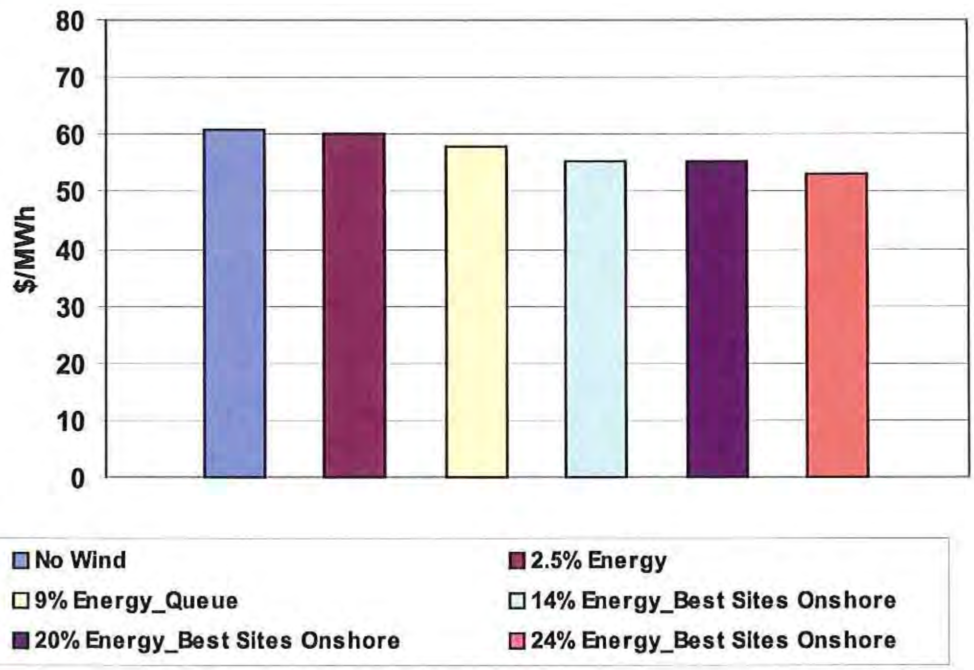


Figure 5–10 Annual load weighted average ISO-NE locational marginal price, S-O-A Forecast, Best Sites Onshore

With no renewable generation on the system, the Locational Marginal Price, or LMP, ranges from a high of approximately $350/MWh to a low of about $38/MWh, as shown in Figure 5–11. (Note: the top figure shows the LMP for the entire year. The middle figure expands the top 1000 hours and the bottom figure expands the lowest 1000 hours.) With increasing penetration of wind to the system, the highest cost is reduced to about $344/MWh with the 9%, $329/MWh with 14%, $301/MWh with 20%, and $271/MWh with 24% penetration. As can be seen on the expanded charts there is very little impact at both the high and low ends for the 2.5% and 9% penetrations. The results are more significant at the 14% penetration and beyond but that may be due to the fact that the wind generation in the neighboring systems of NYISO and PJM were also expanded at these higher levels. The lowest cost hours for the 20% and 24% scenarios drops to $10/MWh. As noted in section 5.1, the $10/MWh price is based on the wind dispatch cost. During hours when the LMP is $10/MWh, the wind was curtailed to not allow it to displace nuclear generation. This would be classified as minimum generation events. Note that although not modeled in this study, changes in market rules to allow negative energy market offers, as is currently done in NYISO and PJM, would likely result in LMPs less than zero, as wind resources would compete to stay online to earn Renewable Energy Credits (REC) or other incentives.

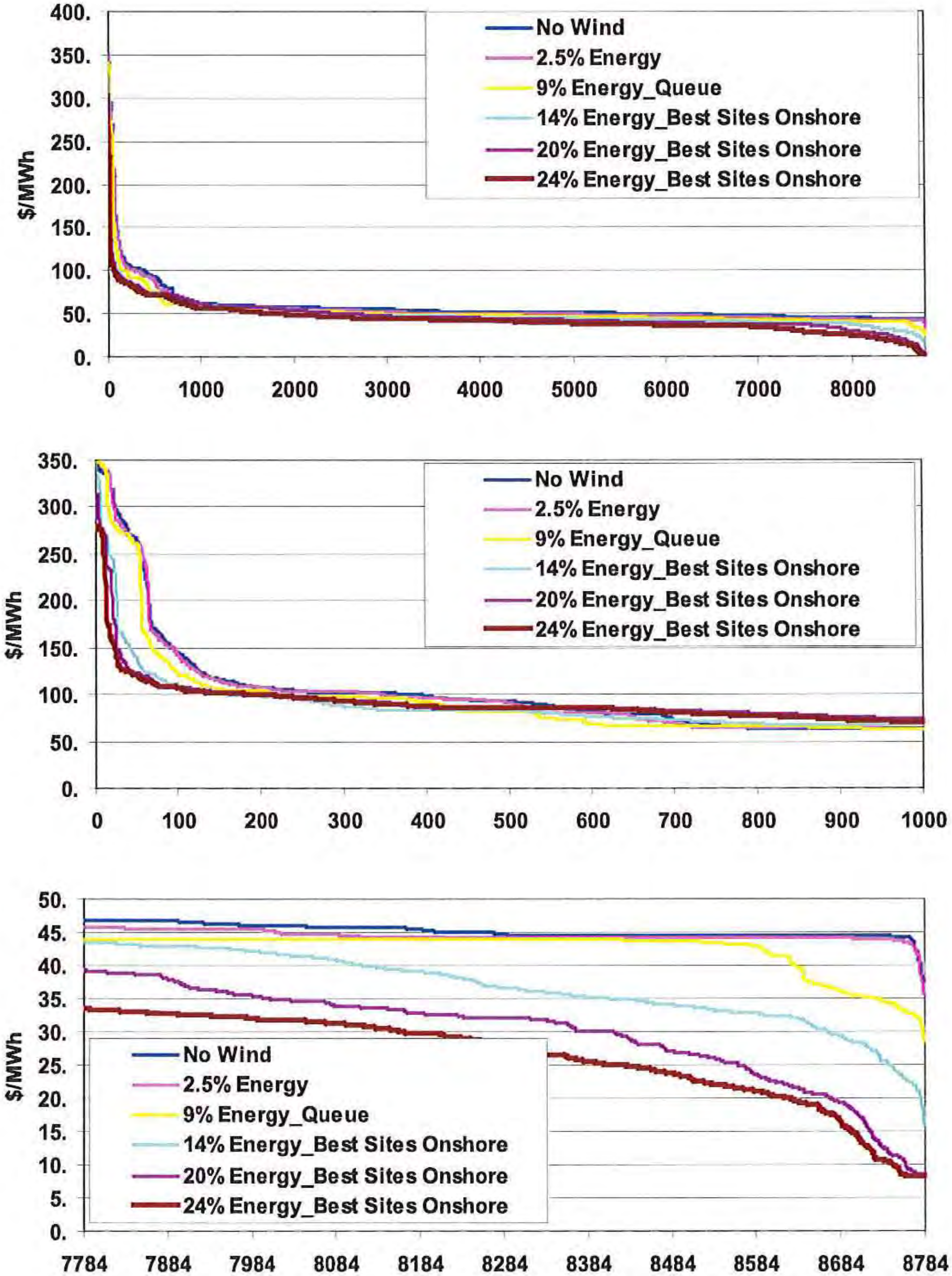


Figure 5–11 Annual LMP duration curve, S-O-A Forecast, Best Sites Onshore

Figure 5–12 shows the total revenue received by each generation type with increasing penetration of wind. As expected the CC generation sees the largest reduction in revenue.

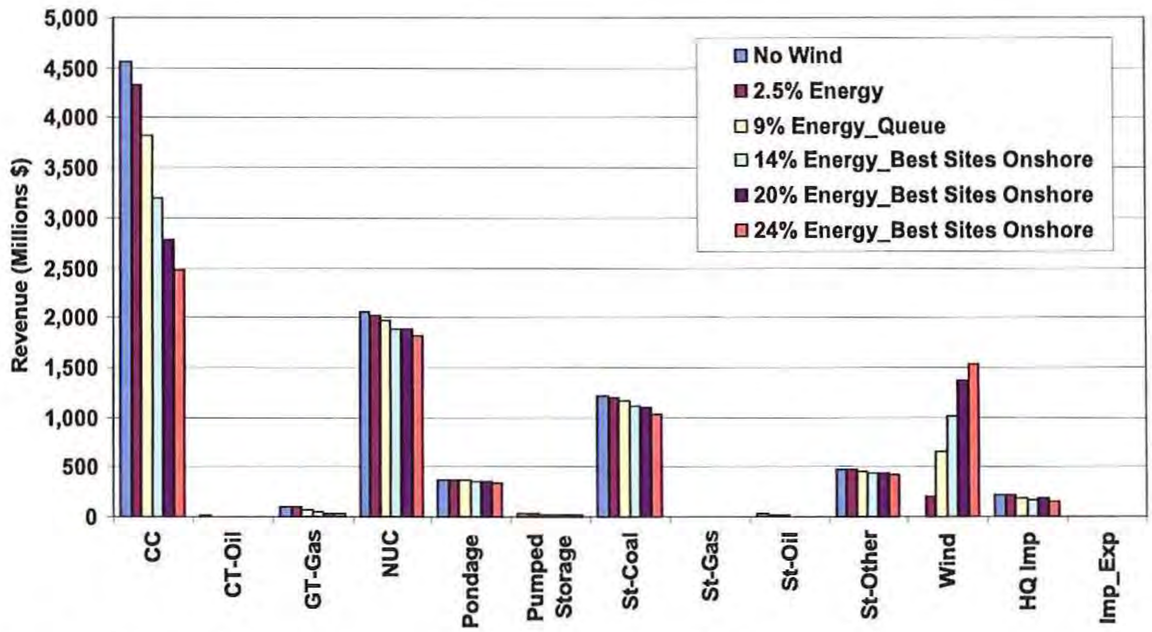


Figure 5–12 ISO-NE revenue by type S-o-A forecast, Best Sites Onshore

Figure 5–13 looks at the revenue and operating cost reduction per the net MWh of wind relative to the No Wind Scenario for CC and St-Coal generation. The operating cost reduction for the CC is relatively flat across the different penetration levels. At higher penetrations, the value of a MWh of wind decreases. The first MWh of wind has higher value than the nth MWh. The net profit reduction ranged from \$11/MWh to \$7/MWh for CC's per MWh of wind. St-Coal net profit reduction was roughly \$3 to \$4/MWh per MWh of wind. Figure 5–14 shows the same data as Figure 5–13 except it is in % relative to the No Wind Scenario.

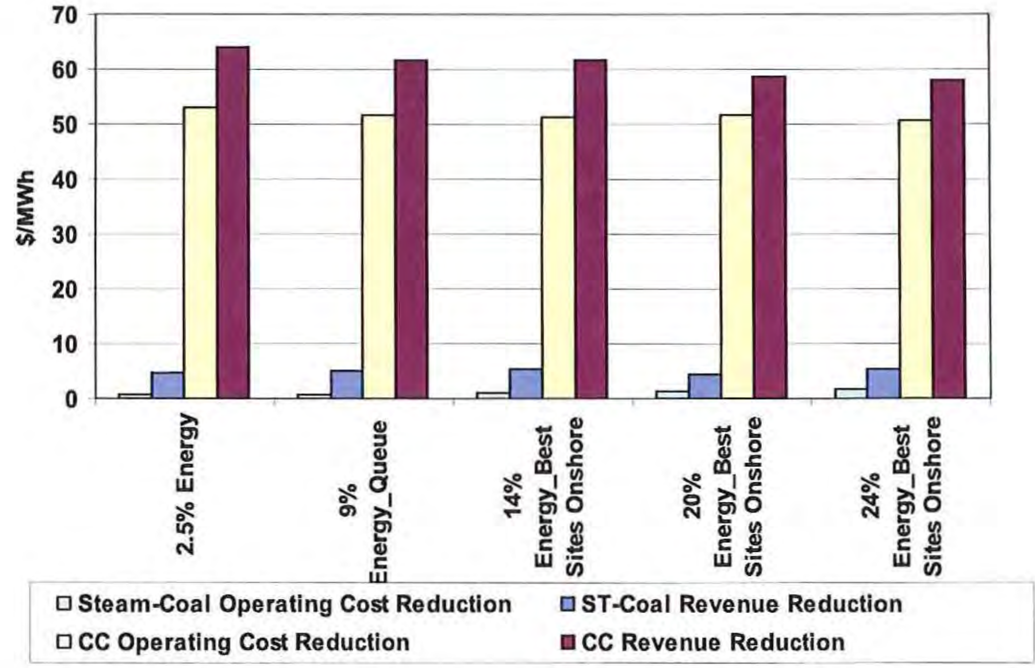


Figure 5–13 ISO-NE CC and St-Coal revenue and operating cost reduction per MWh of wind generation S-o-A forecast, Best Sites Onshore

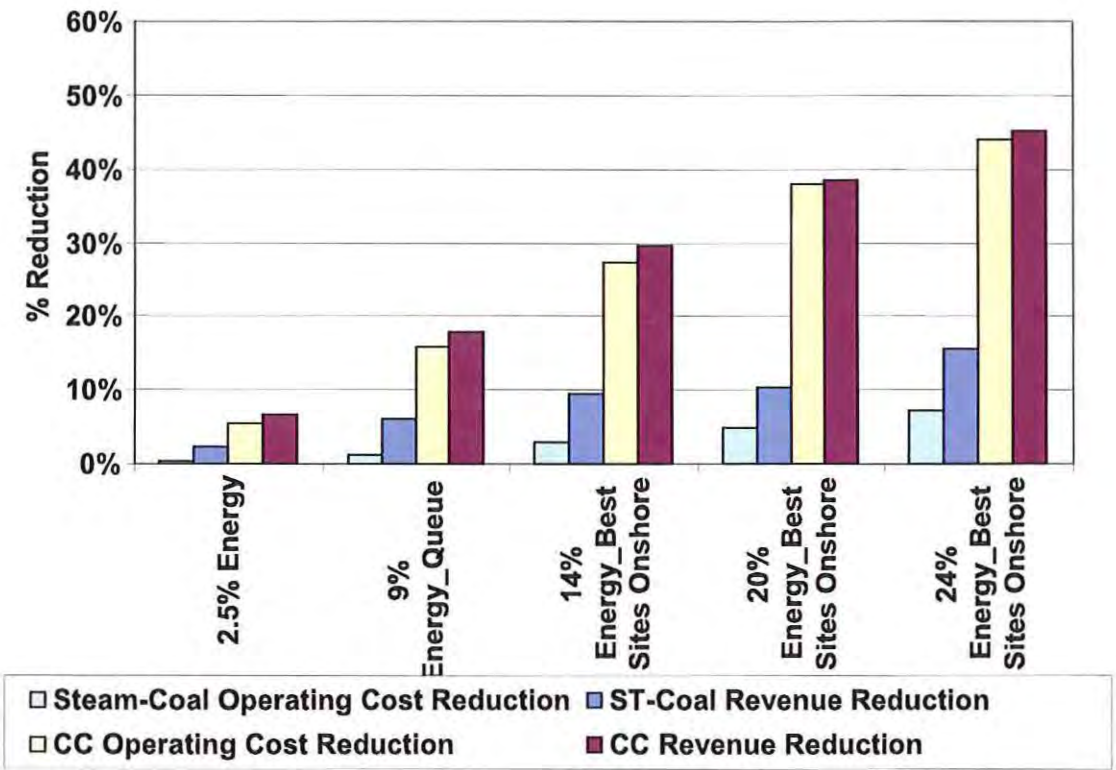


Figure 5–14 ISO-NE CC and St-Coal revenue and operating cost percent reduction per MWh of wind generation S-o-A forecast, Best Sites Onshore

Figure 5–15 shows the ISO-NE operational cost savings, that is, the reduction in fuel, variable O&M and startup costs relative to the No Wind Scenario for the increasing penetration of wind. As expected, the total reduction increases as the wind penetration increases.

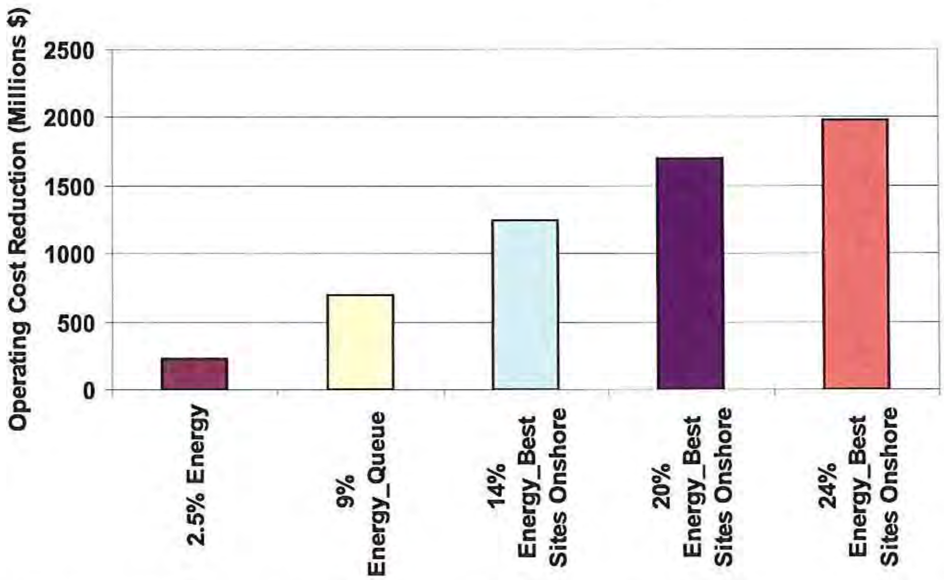


Figure 5–15 ISO-NE operating Cost reduction S-o-A forecast, Best Sites Onshore

Figure 5–16 shows the operating cost reduction per MWh of wind or "Wind Value". This is the average value of the wind energy in each case which varies from \$59 to \$55/MWh. In essence, this is the cost to replace one MWh of energy from wind generation with one MWh of energy from the next available resource from the assumed fleet of conventional resources. As with the revenue reduction for CC and St-Coal per MWh of wind, the wind value decreases as the penetration increases.

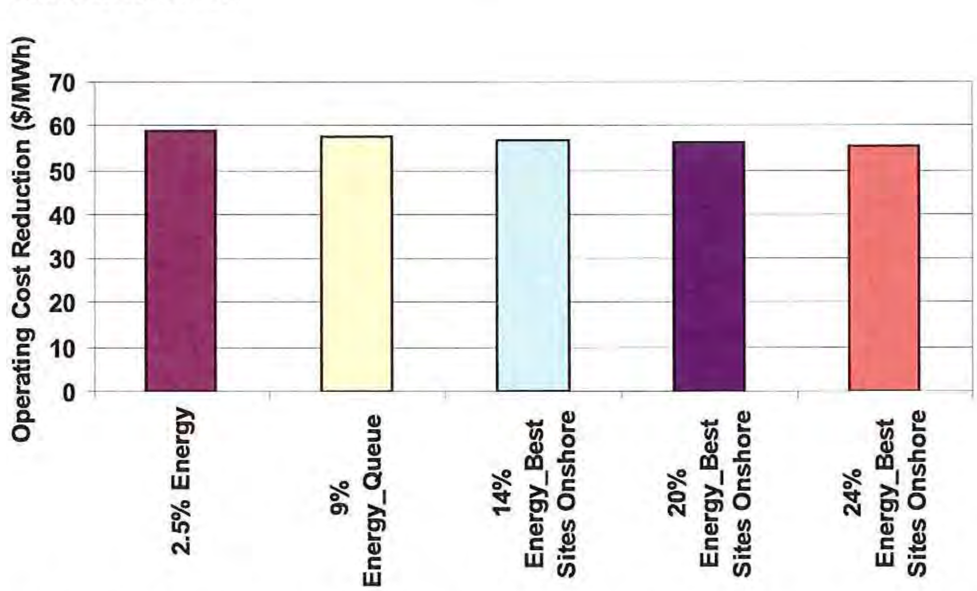


Figure 5–16 ISO-NE operating cost reduction per MWh of wind generation S-o-A forecast, Best Sites Onshore

Figure 5–17 shows the total load payments for energy for the increasing penetration of wind. The reduction for the 24% scenario is roughly $1.6 Billion. This is an 18% reduction as compared to the No Wind Scenario.

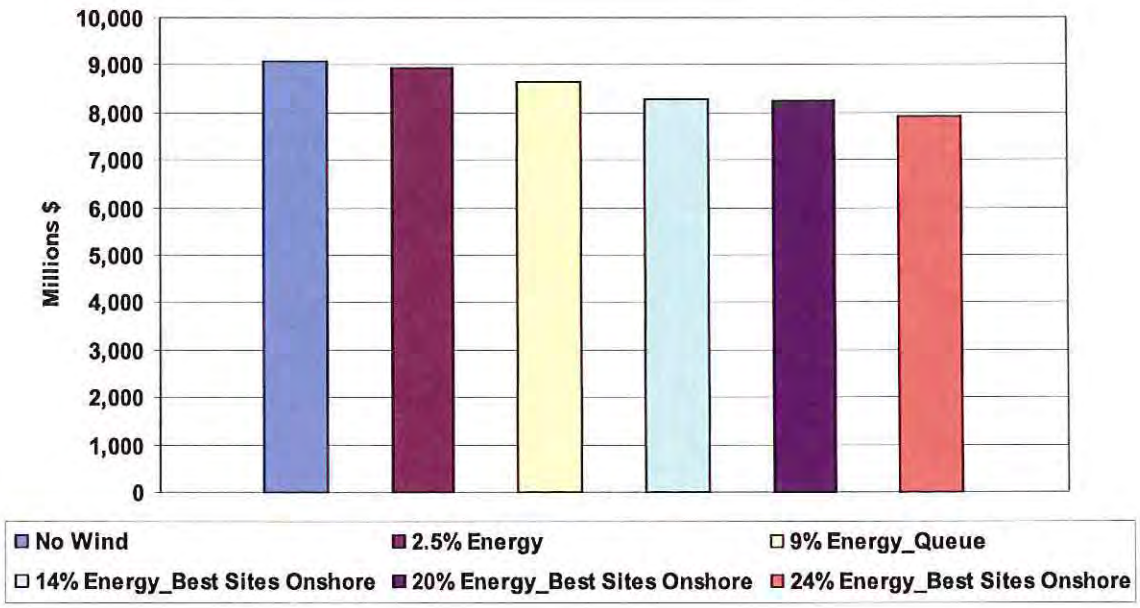


Figure 5–17 ISO-NE wholesale load payments for energy, S-o-A forecast, Best Sites Onshore

5.2.1.1 ***Transmission Constraints***

Table 5–3 shows the limits for the interfaces modeled and Table 5–4 shows the maximum and minimum flow on each interface constraint in ISO-NE for the copper sheet case for increasing wind penetration. The red highlighted cells show where the flow would have been above the limit for the constrained case for the various scenarios.

Table 5–3 ISO-NE transmission interface limits, S-o-A forecast, Best Sites Onshore

	NPCC 2019		2 GW		4GW		8GW	
Interface	Min Rating (MW)	Max Rating (MW)	Min Rating (MW)	Max Rating(MW)	Min Rating (MW)	Max Rating (MW)	Min Rating (MW)	Max Rating (MW)
North-South	-2700	2700	-3800	3800	-6800	6800	-7400	7400
Boston Import	-4900	4900	-4900	4900	-4900	4900	-4900	4900
New England East-West	-3500	3500	-4300	4300	-7900	7900	-8600	8600
Connecticut Export	-3900	3900	-4200	4200	-4500	4500	-5000	5000
Connecticut Import	-3600	3600	-5300	5300	-6600	6600	-7000	7000
Southwestern Connecticut Import	-3650	3650	-3650	3650	-3650	3650	-3650	3650
Norwalk-Stamford Import	-1650	1650	-1650	1650	-1650	1650	-1650	1650
New York-New England	-1600	1600	-1600	1600	-1600	1600	-1600	1600
Orrington South	-1200	1200	-2500	2500	-5500	5500	-6100	6100
Surowiec South	-1150	1150	-2100	2100	-5200	5200	-5800	5800
Maine-New Hampshire	-1450	1450	-2700	2700	-5700	5700	-6400	6400
SEMA Export	-9999	9999	-9999	9999	-9999	9999	-9999	9999
West - East	-4400	4400	-4400	4400	-5100	5100	-5800	5800
NB - NE	-500	1000	-500	1000	-500	1000	-500	1000
SEMA/RI Export	-3300	3300	-4200	4200	-6500	6500	-6500	6500

Table 5–4 ISO-NE Copper Sheer transmission interface summary S-o-A forecast, Best Sites Onshore

	No Wind		2.5%		9%		14%		20%		24%	
Interface	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)
North-South	196	4904	-46	3987	20	5605	332	7126	320	8356	360	9639
Boston Import	526	4615	549	4464	633	5328	660	5755	678	5260	-1159	3363
New England East-West	-1451	2720	-1213	3760	-784	4214	-1766	4395	-1795	5254	-1751	5631
Connecticut Export	-2652	1464	-2723	1379	-3031	1175	-3697	1249	-3923	1259	-2924	1342
Connecticut Import	-867	2986	-669	3001	-608	3331	-668	3692	-663	3918	-890	2919
Southwestern Connecticut Import	176	2151	184	2157	252	2363	196	2430	68	2612	70	2706
Norwalk-Stamford Import	470	1255	438	1255	430	1279	386	1355	479	1466	343	1465
New York-New England	-1525	1600	-1525	1582	-1525	1525	-1600	1600	-1600	1600	-1600	1600
Orrington South	-304	1804	-211	1897	-518	2390	-393	3321	-206	4669	-391	5074
Surowiec South	-672	1761	-587	1988	-1435	3104	-1254	3747	-305	5957	-407	7414
Maine-New Hampshire	-952	2583	-897	2559	-1589	4687	-1049	5778	-438	5945	-415	7116
SEMA Export	-1622	785	-1422	1131	-1035	2750	-1408	975	-1215	1319	-1599	901
West - East	-2227	2192	-3267	1501	-3074	1129	-3405	1854	-4954	1791	-5185	1851
NB - NE	-500	1000	-500	1000	-1000	1000	-1000	1000	-500	1000	-500	1000
SEMA/RI Export	-591	3369	-406	3502	-691	4476	-1312	2811	-1908	2634	-2142	2381

Table 5–5 details what transmission overlay each scenario uses. Transmission congestion can cause cheaper generation to be displaced inside and/or outside the system. In extreme conditions wind generation may be curtailed, if the LMP drops below $10/MWh.

Table 5–5 Transmission overlay summary

Scenario	Transmission Overlay
No wind	NPCC 2019
2.5% Energy	NPCC 2019
9% Energy	2GW
14% Energy	2GW
20% Energy	4GW
24% Energy	8GW

Figure 5–19 through Figure 5–26 show flow duration curves for the interfaces that were highlighted in red in Table 5–4. Note that negative flows represent flow in the opposite direction. For example in Figure 5–26, positive flow represents exports from ISO-NE to the Maritimes and negative flow represents imports into ISO-NE from the Maritimes. The flows use the constrained case.

Note that the North – South interface is constrained for roughly 3000 hours in the 14% scenario. This has a minor impact on overall operations, for example this congestion had minor impacts on LMP. Figure 5–18 shows the duration flow on the North/South interface for the 14% energy Scenario. It also shows duration of the congestion cost associated with the interface. The interface is not closed therefore other paths are available for power to flow. This is shown in the figure. Although there are roughly 3000 hours where the interface is at its limit there are only 200 hours where the congestion cost is greater than $1/MWh. Basically, for 2800 hours there is an alternate path to deliver the power to Southern NE. This result may seem counterintuitive to historical operation. Note that the transmission system has been expanded based on the Governors' 2 GW overlay.

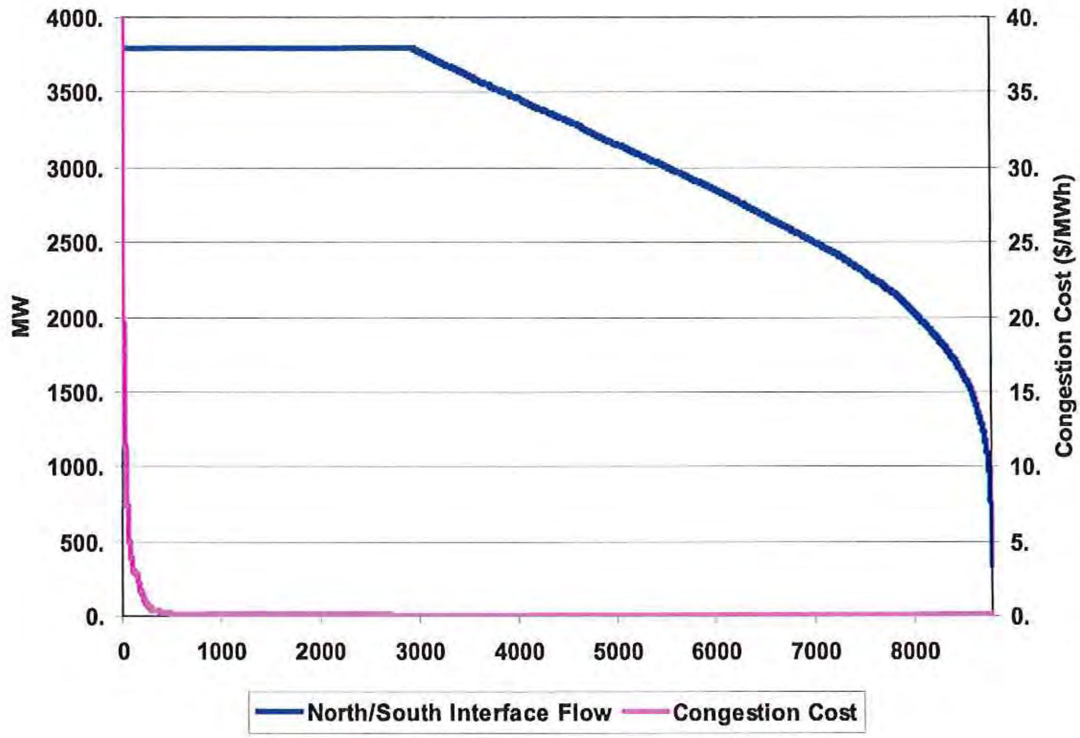


Figure 5–18 North/South Interface Flow vs. Congestion Cost 14% Energy_Best Sites Onshore

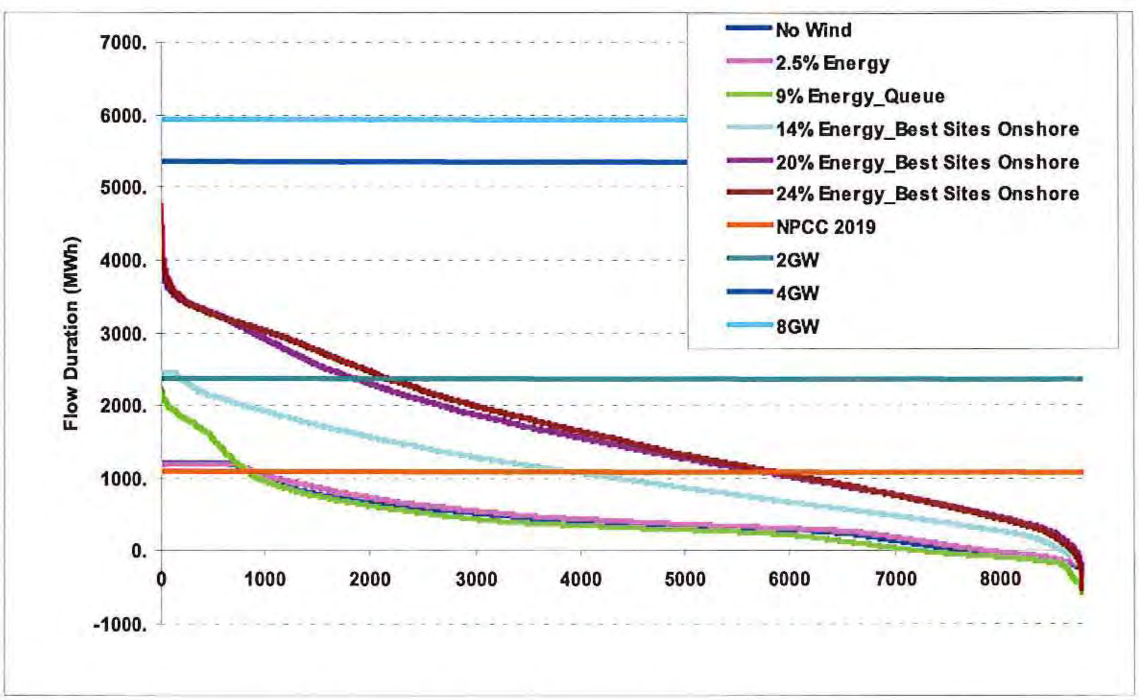


Figure 5–19 Orrington South interface flow, S-o-A forecast, Best Sites Onshore

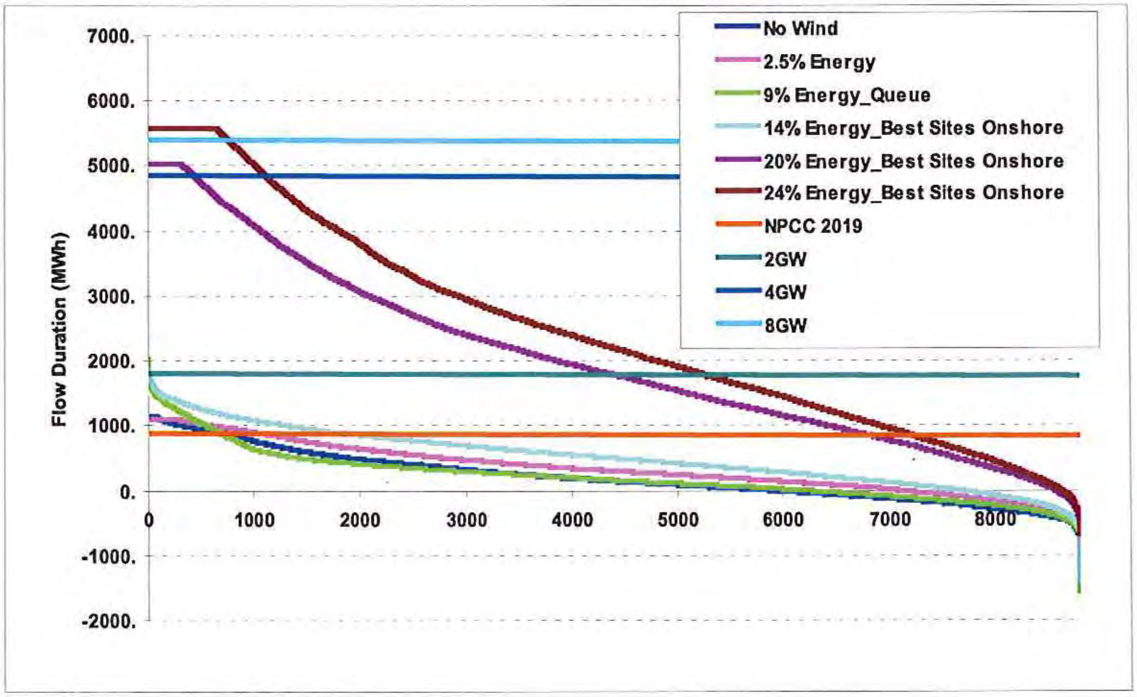


Figure 5–20 Surowiec South interface flow, S-o-A forecast, Best Sites Onshore

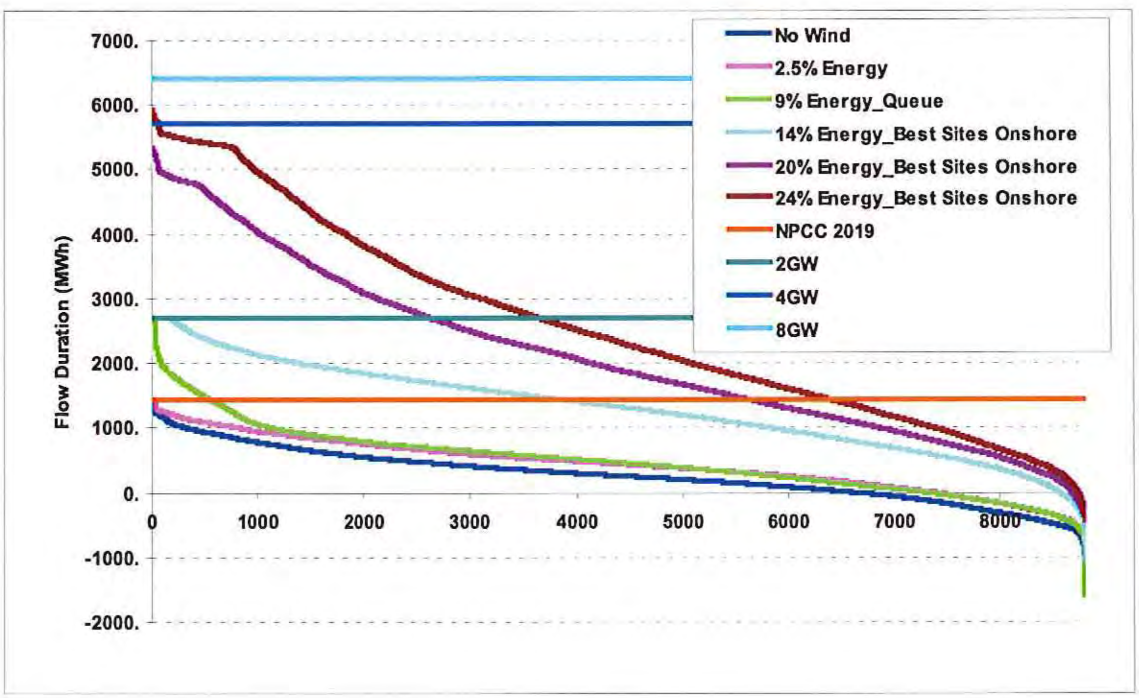


Figure 5–21 Maine/New Hampshire interface flow, S-o-A forecast, Best Sites Onshore

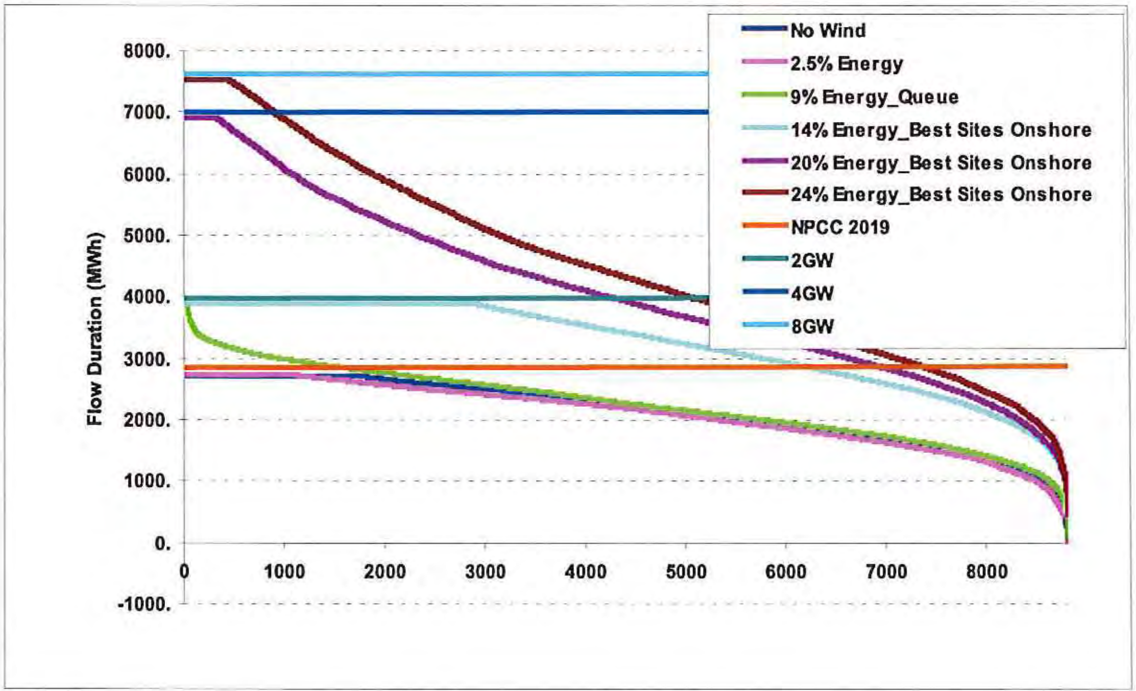


Figure 5–22 North/South interface flow, S-o-A forecast, Best Sites Onshore

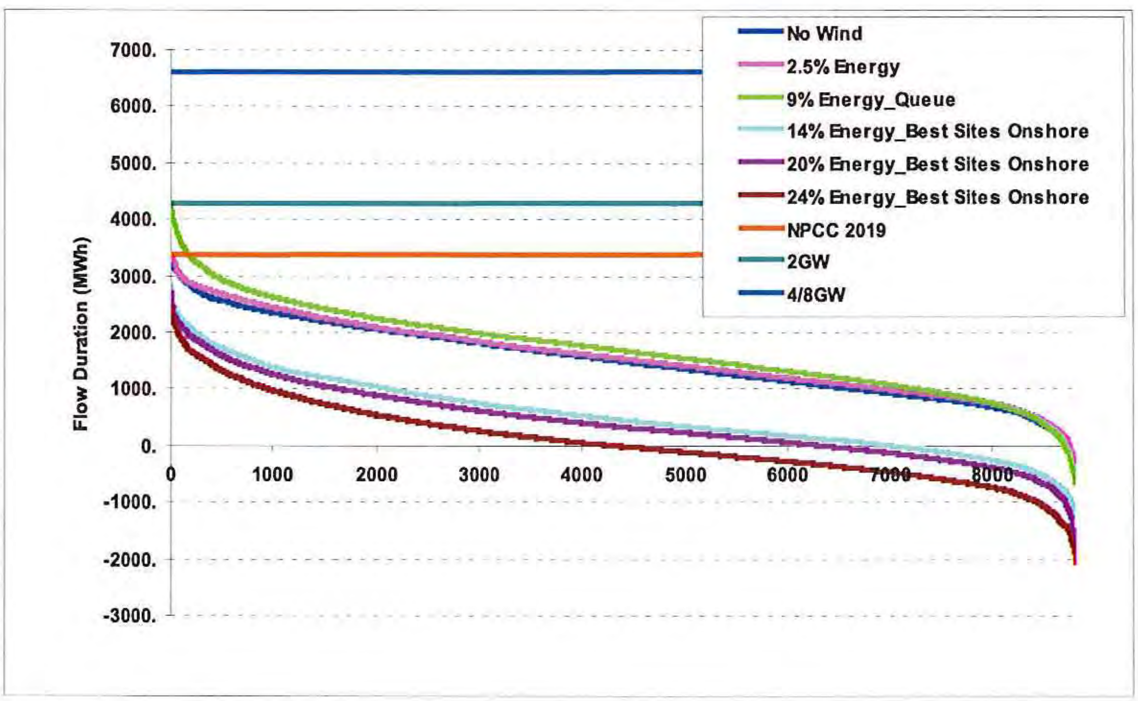


Figure 5–23 SEMA/RI Export interface flow, S-o-A forecast, Best Sites Onshore

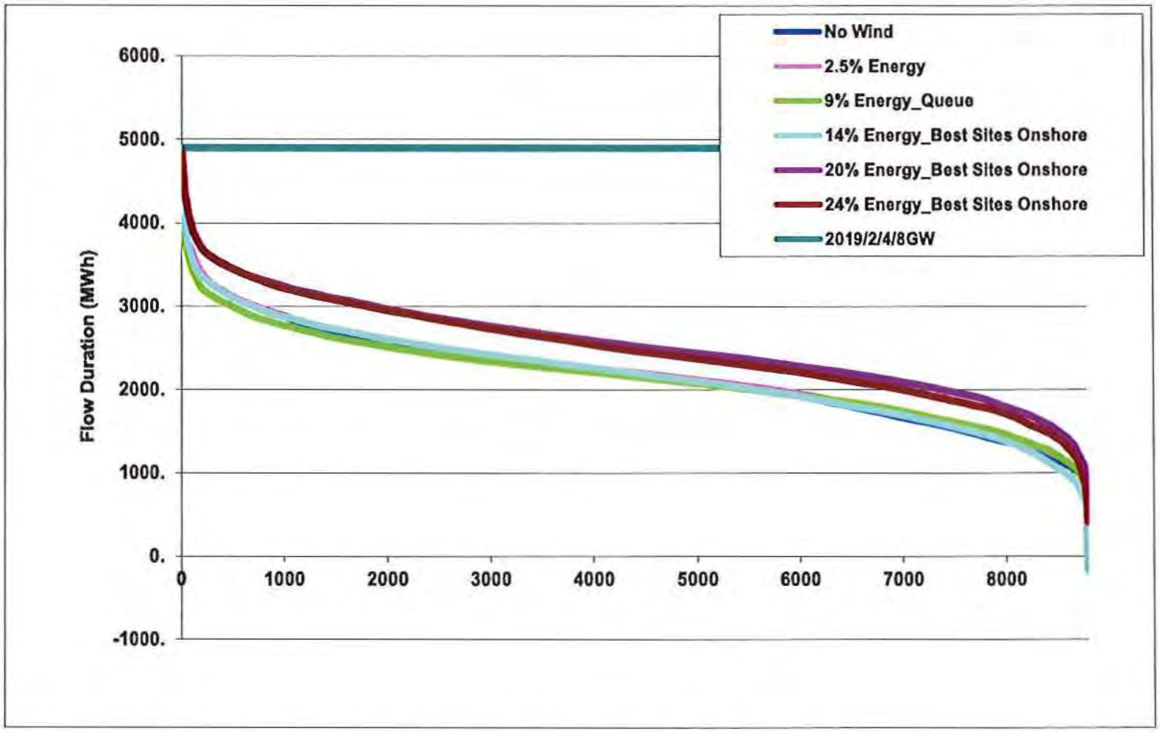


Figure 5–24 Boston Import interface flow, S-o-A forecast, Best Sites Onshore

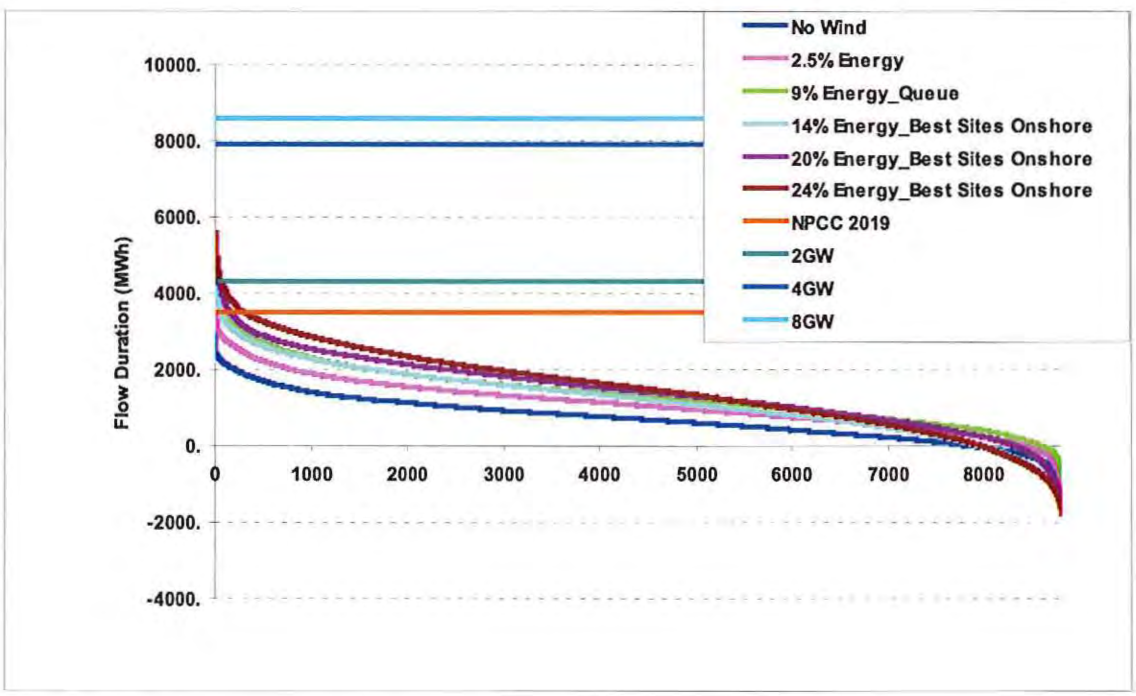


Figure 5–25 East-West interface flow, S-o-A forecast, Best Sites Onshore

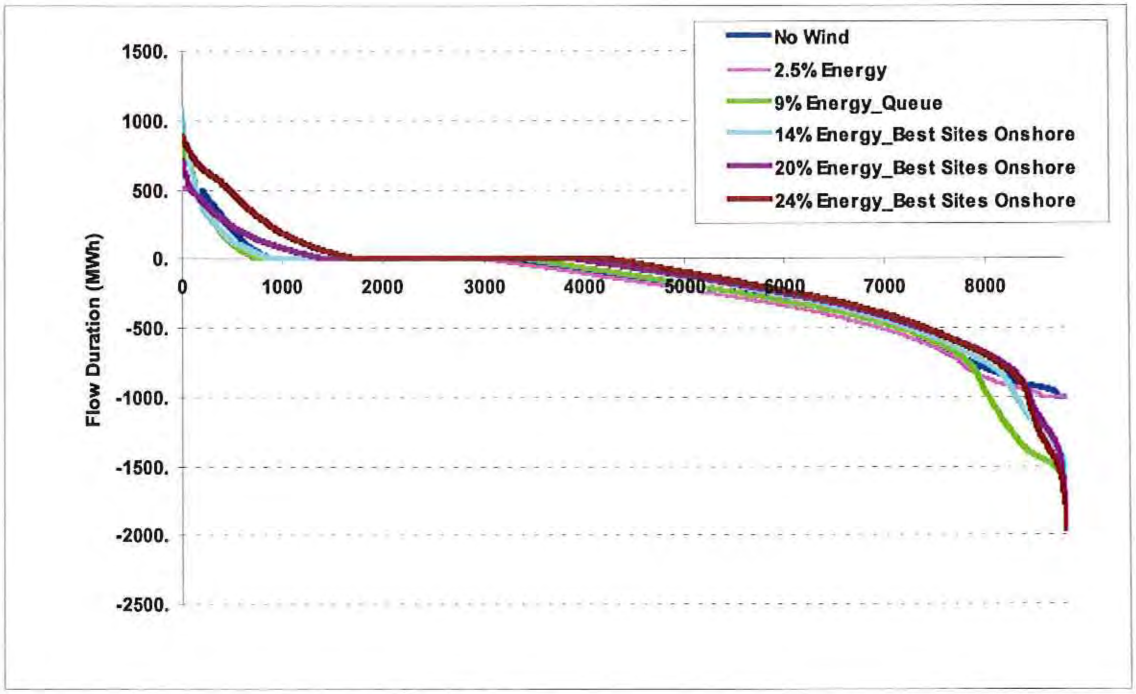


Figure 5–26 ISO-NE to NB interface flow, S-o-A forecast, Best Sites Onshore

5.2.1.2 ***Ramp and Range Capability***

The impact on the range and ramp availability was analyzed for the various penetration scenarios. The range is calculated based on what the unit was dispatched at and the room it had left up or down respectively. The units that contribute to the range are steam other, steam coal, combined cycle, pumped storage hydro and conventional hydro. Wind is not considered. The ramp is a unit's capability to move up or down over a one minute period. Table 5–6 summarizes the capacity type and ramp rates assumed.

Table 5–6 Ramping capability by generation type

Type	Ramp Rate (%/min)
CC	4%
CT gas/oil	14%
Hydro	22%
ST-gas/coal/oil/other	3%
Pumped Storage Hydro	19%

Figure 5–27 and Figure 5–28 show duration curves of the hourly range up and range down capacity available for the various scenarios. The graphs are based on what is committed and online for operation. The maximum range up available varies from roughly 8,100 MW in the No Wind Scenario to 9,964 MW in the 24% scenario. The minimum range up available varies from roughly 905 MW in the No Wind Scenario to 768 MW in the 24% scenario. The maximum range down available varies from roughly 18,600 MW in the No Wind Scenario to 15,298 MW in the 24% scenario. The minimum range down available varies from roughly 1,475 MW in the No Wind Scenario to 0 MW in the 24% scenario. The 24% case has about 16 hours when the range down is 0 MW. This is less than 0.2% of the year. In this situation the wind would potentially be curtailed to free up range down capacity, since as conventional generation units are backed down to lower operating levels there is less maneuverability down.

The results are as expected, with increased penetration of wind, other types of generation are backed down to lower operating levels creating increased range up capacity. The opposite is true for the range down capacity.

The MAPS analysis shows no spinning reserve violations up to 24% penetration of wind. The minimum range up capacity was greater than the spinning reserve requirement built into the model.

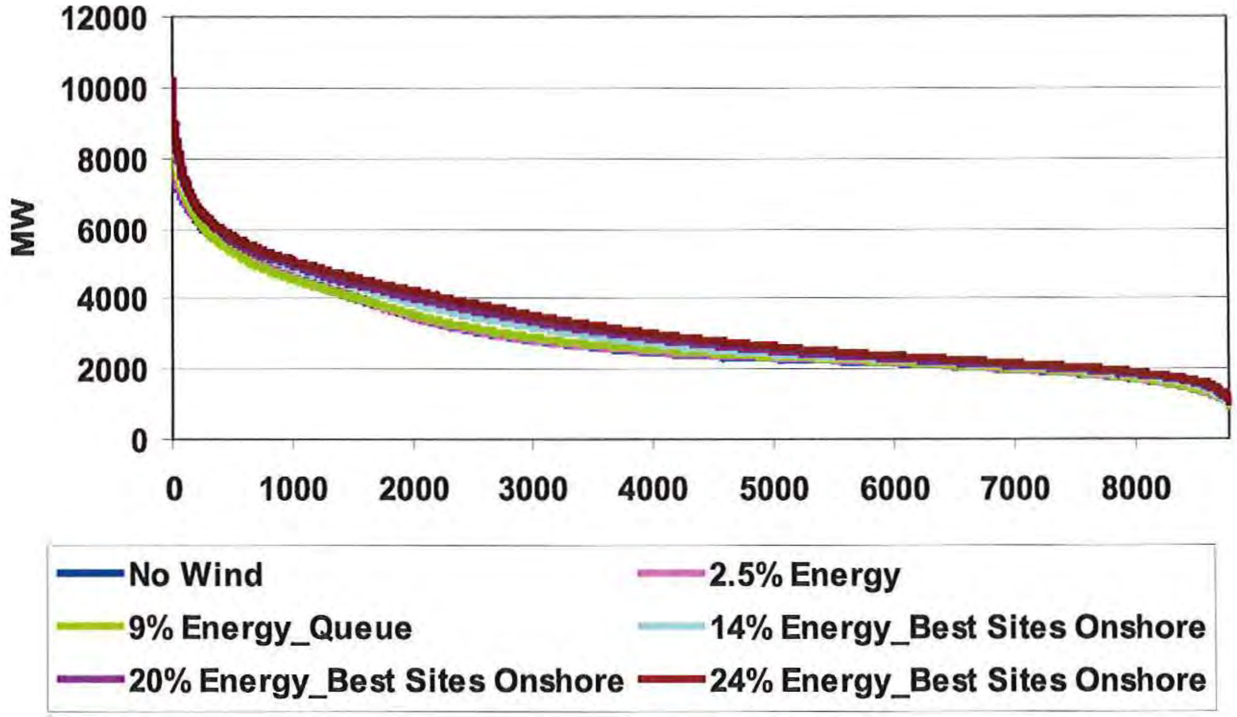


Figure 5–27 Hourly Range Up Capability S-o-A forecast, Best Sites Onshore

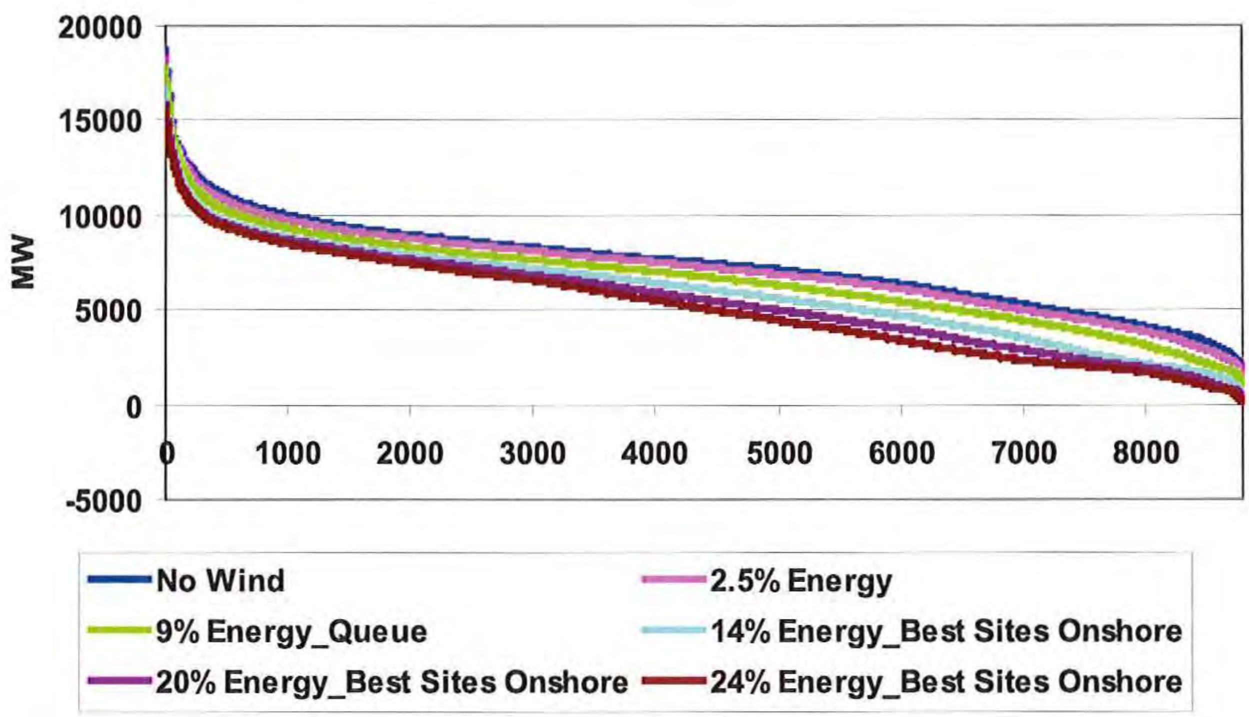


Figure 5–28 Hourly Range down Capability S-o-A forecast, Best Sites Onshore

Figure 5–29 and Figure 5–30 show duration curves of the hourly ramp up and ramp down capacity available for the various scenarios. The data represents the available unit ramp capability at the beginning of the hour. The one minute ramping capability only includes headroom effects for the first minute and may not be sustainable over periods longer than one minute. For example, if a 500 MW unit has a ramp rate of 5%/min or 25 MW/min, and is dispatched at 400 MW, it can only provide ramping for 4 minutes. If the same unit is dispatched at 490 MW then it can provide 10 MW for the first minute. The maximum ramp up capability available varies from roughly 1,250 MW/min in the No Wind Scenario to 1,230 MW/min in the 24% scenario. Most of the high values of ramp occur in off-peak hours and come from the PSH and conventional hydro. There is also some contribution from thermal units that are needed for the next day and cannot be shut down at night. The minimum ramp up capability varies from roughly 206 MW/min in the No Wind Scenario to 123 MW/min in the 24% scenario. The maximum ramp down capability available varies from roughly 2,440 MW/min in the No Wind Scenario to 1,840 MW/min in the 24% scenario. The minimum ramp down available varies from roughly 101 MW/min in the No Wind Scenario to 0 MW in the 24% scenario. The 24% case has about 16 hours when the ramp down is 0 MW/min. This is less than 0.2% of the year.

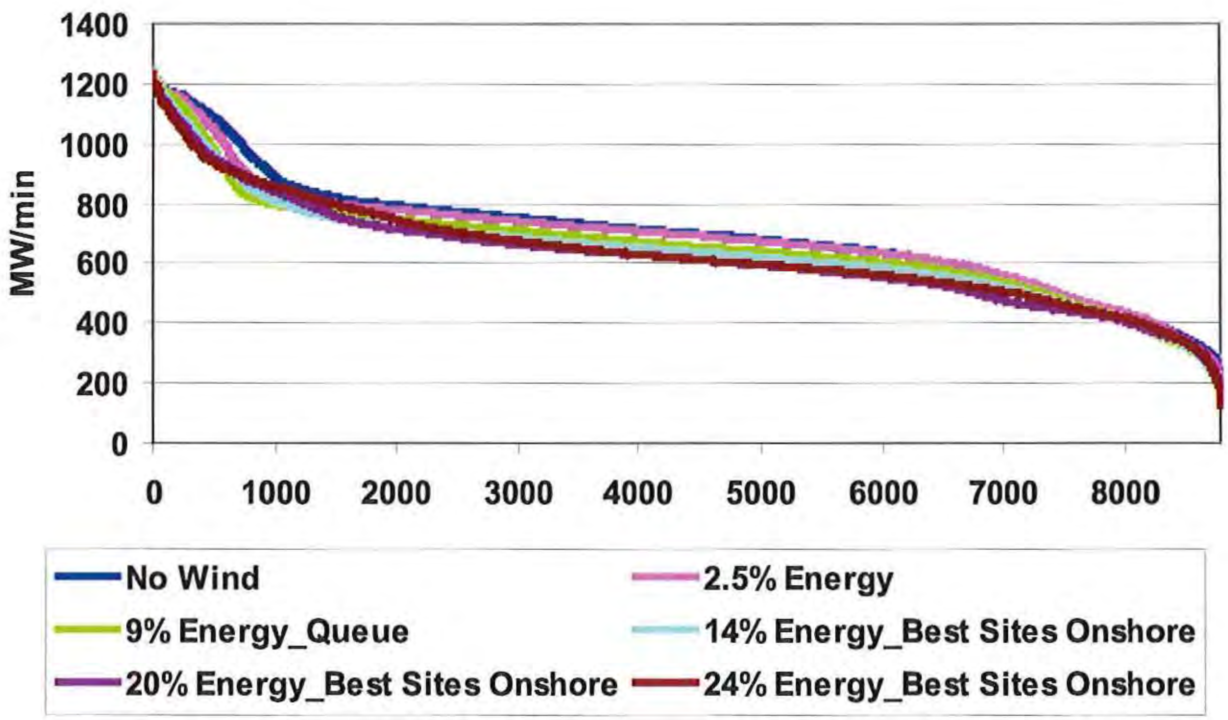


Figure 5–29 Hourly Ramp Up Capability S-o-A forecast, Best Sites Onshore

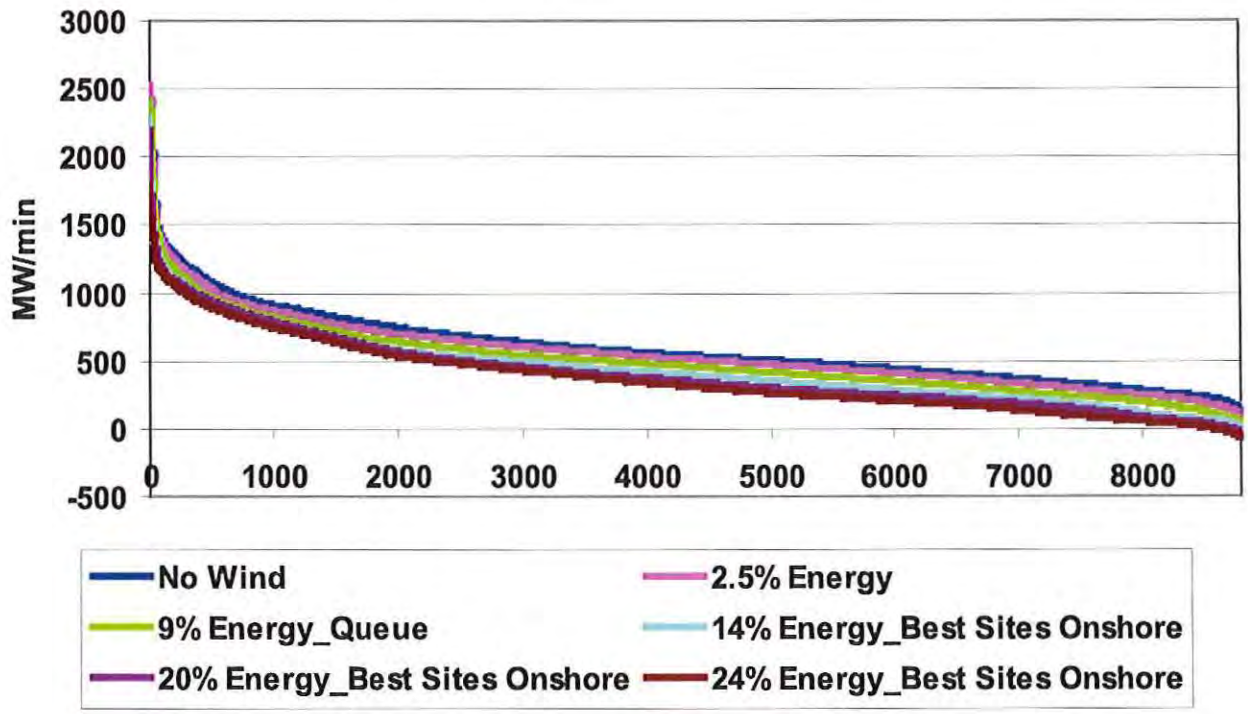


Figure 5–30 **Hourly ramp down capability S-o-A forecast, Best Sites Onshore**

Figure 5–31 compares the hourly ramp up/down capability against the hourly load. The upper figure shows the total range and the bottom figure expands the graph to just show the hours with less than +/- 100 MW/min ramping capability. The ten-minute spinning reserve for ISO-NE is 700 MW, which would correspond to a ramp up capability of 70 MW/min. As can be seen from the scatter plot, the ramp up capability never seems to be a problem: its lowest point is roughly 123 MW/min. Depending on the wind penetration the regulation requirement ranges from roughly 102 MW to 313 MW (see section 4.6.1). This can be compared to the regulation requirements, which increase from roughly 80 MW to 310 MW at 20% penetration, as seen in section 4.6.1. Over a 5-minute period, 310 MW would translate to 62 MW/min, which is approximately half of what is available, indicating that the increased regulation requirement could easily be met.

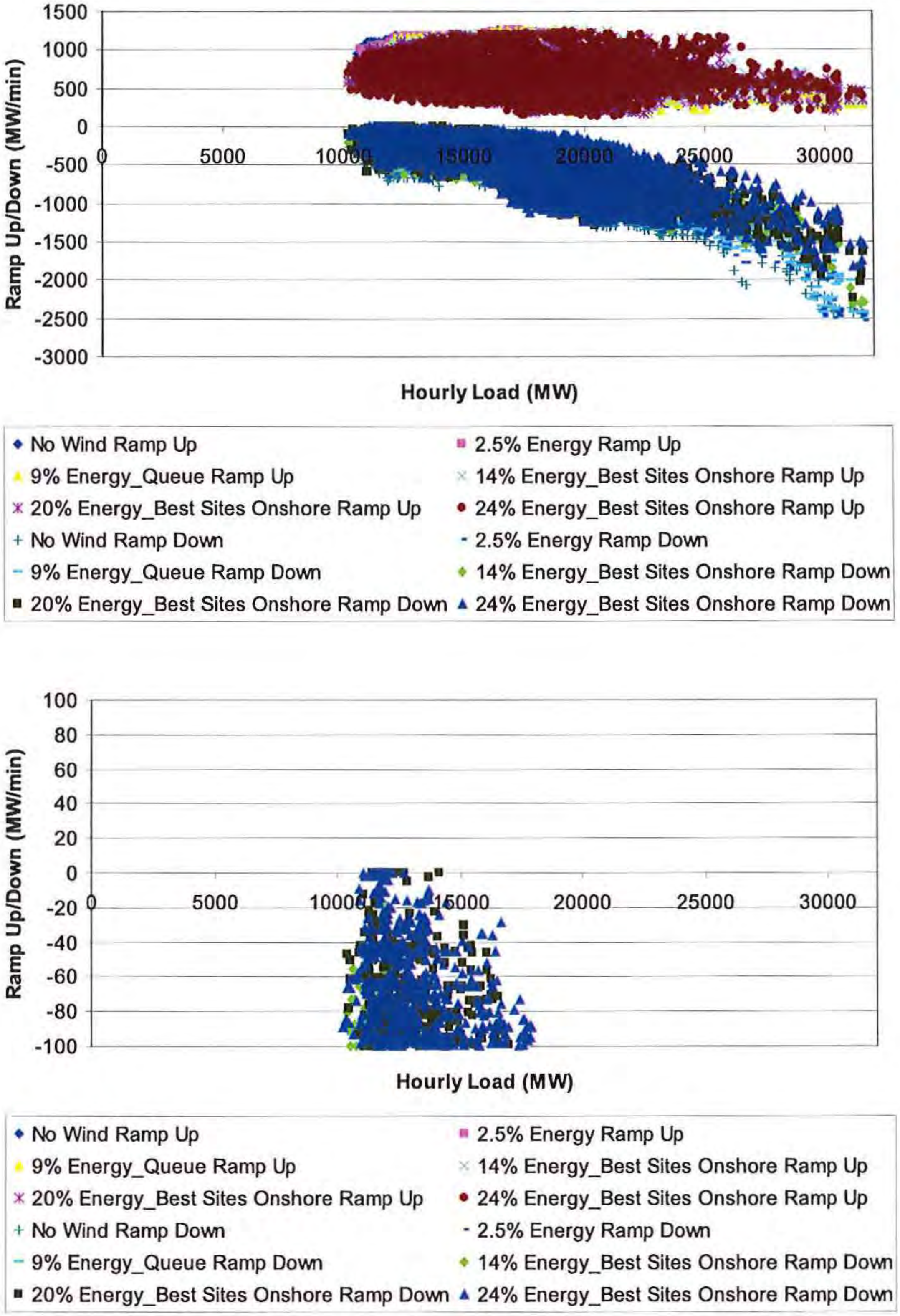


Figure 5–31 Hourly Ramp Up/Down Capability MW/min vs. Load, S-o-A forecast, Best Sites Onshore

The ramp down capability may be deficient a few hours and possibly require either changes to the unit commitment or spilling of some wind energy. Table 5–7 shows the number of hours when the ramp down capability is less than 100 MW/minute for the various wind penetration scenarios. Although relatively small at the lower penetrations the number of hours becomes more significant at the higher penetrations.

Table 5–7 Number of hours with ramp down capability < 100 MW/minute.

Scenario	# Hours
No Wind	0
2.5% Energy	3
9% Energy_Queue	43
14% Energy_Best Sites Onshore	185
20% Energy_Best Sites Onshore	374
24% Energy_Best Sites Onshore	537

5.2.1.3 Weekly Dispatch and Ramp/Range analysis

The previous section examined the operational impacts of renewable generation from an annual basis. This section examines a spring and summer week to look at the changes in operation more closely.

Table 5–8 is the legend for the following figures. The solid color blocks represent the generation. PSH (in solid red) is counted as generation when in generating mode, due to the limitations of this type of plot, PSH is not shown as a solid area when in pumping mode. The light blue line represents the load plus exports, plus the pumping of the PSH. The dark blue line is the native load. The pink line represents the net load (native load minus the wind generation). The red line is the PSH generation; where a positive value is generation. The dark green line is the import/exports into ISO-NE from NY, HQ, and the Maritimes. A positive value is an import.

Table 5–8 Legend

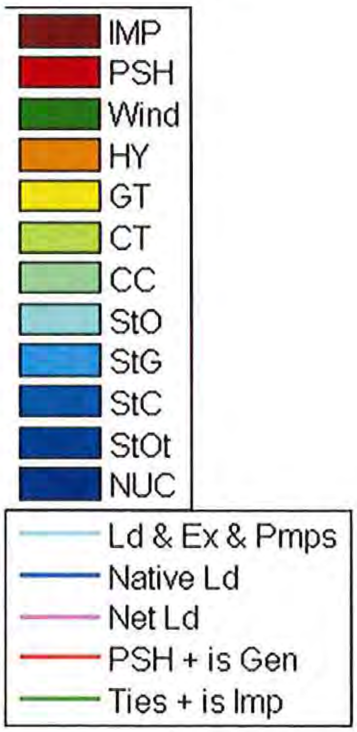


Figure 5–32 shows the operation of the generation by type within ISO-NE when there is no wind generation present for the week of April 13. The Nuclear, St-Coal, and St-Other generation were flat. The St-Other generation represents cogen, refuse, and wood burning generation. The hydro and PSH provided the bulk of the peaking operation and the combined-cycle filled in the intermediate operation.

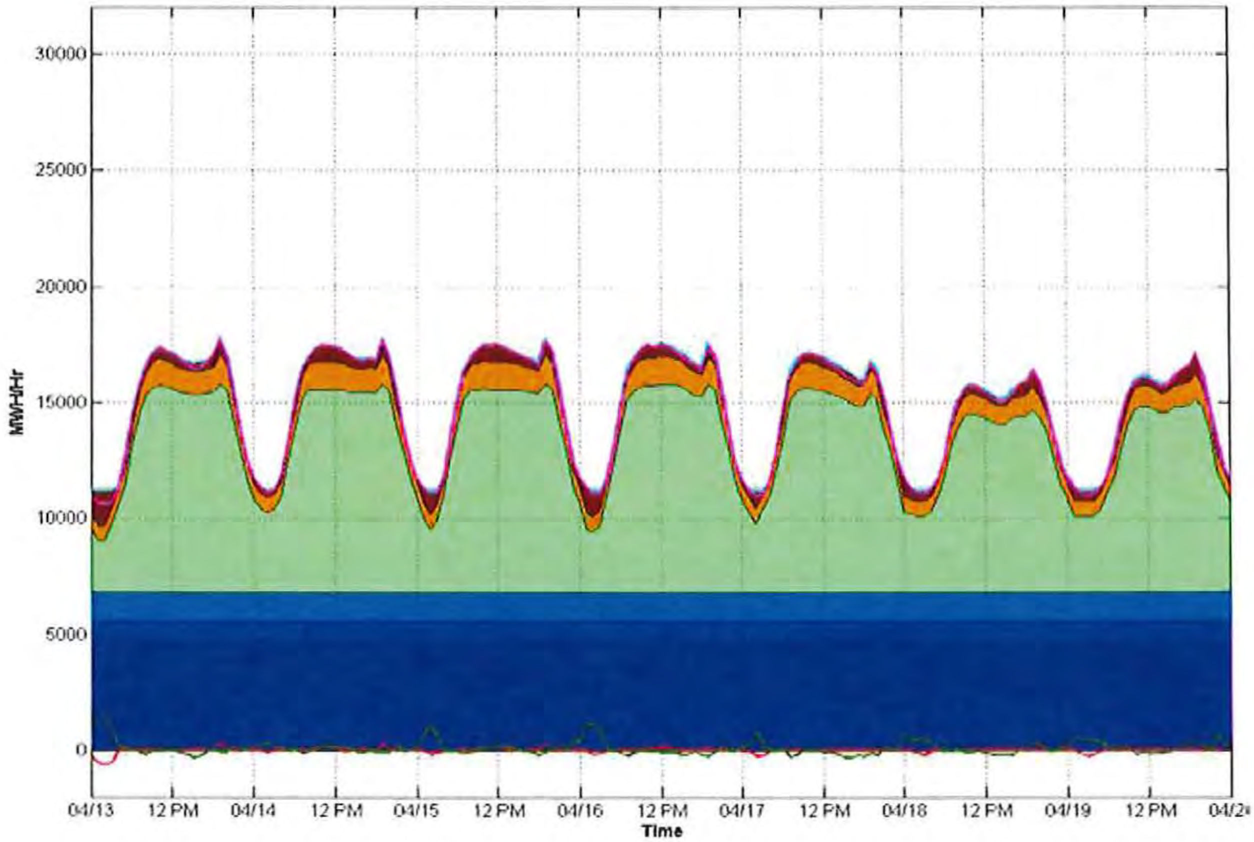


Figure 5–32 ISO-NE dispatch, week of April 13, no wind

Figure 5–33 shows how this operation changed for the 2.5% penetration level. The nuclear, St-Other, and St-Coal generation remain but the dispatch of the other generation has begun to change. The most noticeable shift is the introduction of the green band, which represents the wind generation. The hydro generation has shifted slightly. Each hydro plant was scheduled to meet specific monthly energy targets. Introduction of renewable generation could cause the hydro to shift the hourly schedule but the monthly energy production would remain constant. The bulk of the displacement came from the combined-cycle units, which is consistent with what was seen on an annual basis. Also note that the total generation each hour changed slightly from the previous figure. This was because the exports changed when the wind generation was added in New England while no additional wind generation was added in other regions for the 2.5% penetration level.

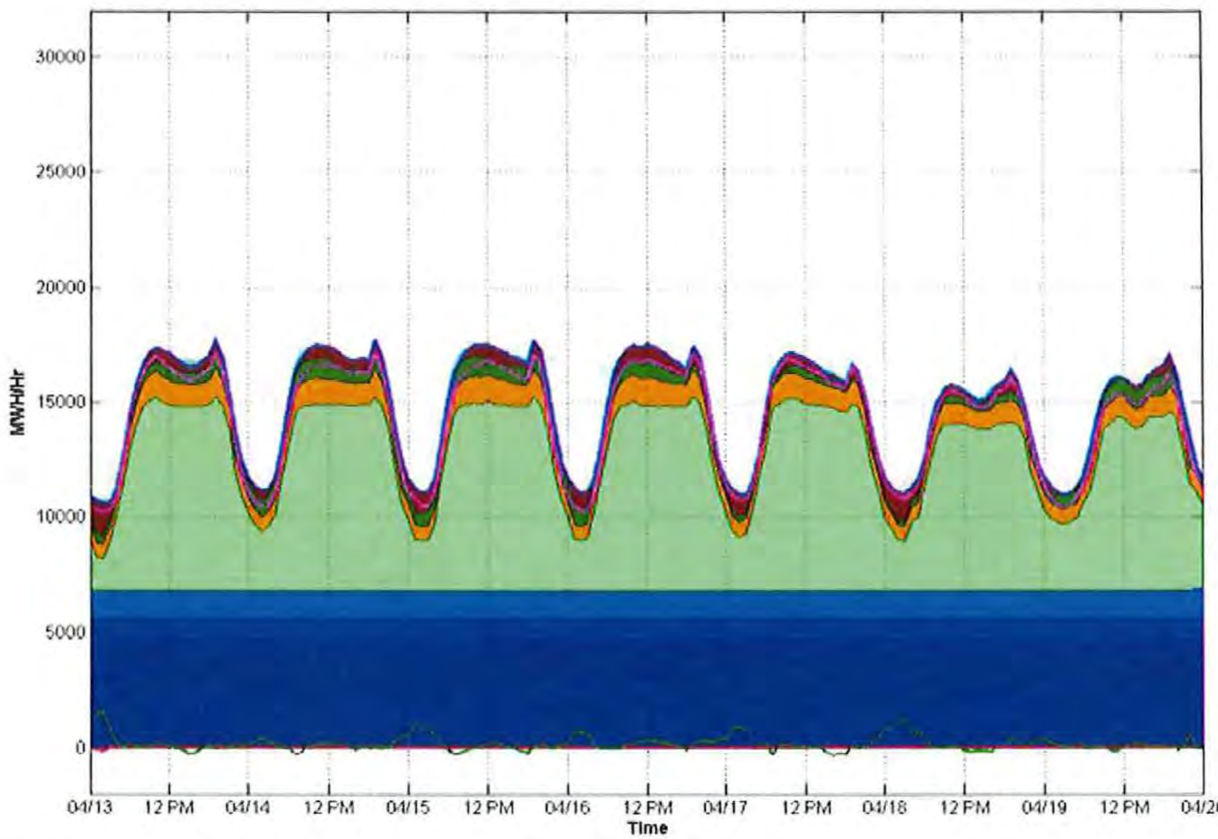


Figure 5–33 ISO-NE dispatch, week of April 13, 2.5% Energy, S-o-A forecast

Figure 5–34 shows how this operation changed for the 9% penetration level. The nuclear and St-Other remain constant but there are few hours where the St-Coal generation is displaced. The combined cycle generation is 75% of what it was with no wind generation.

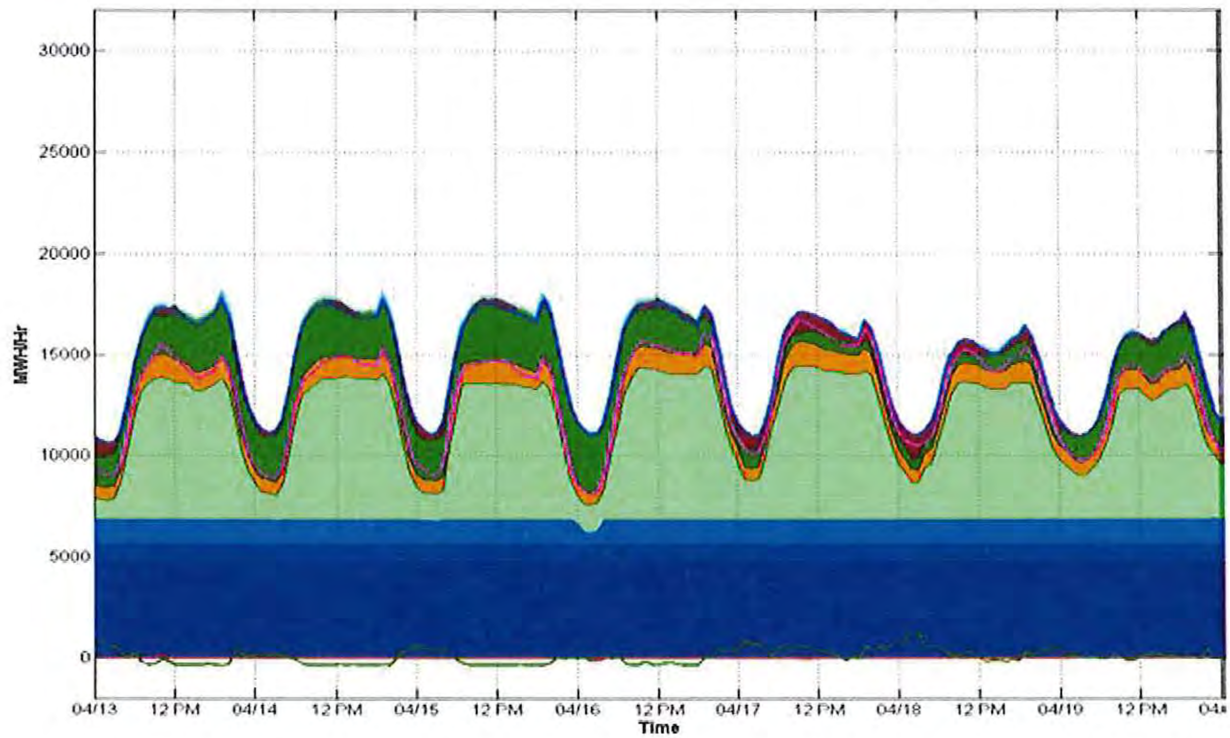


Figure 5–34 ISO-NE dispatch, week of April 13, 9% Energy, S-o-A forecast

Figure 5–35 shows how this operation changed for the 14% penetration level. The nuclear and St-Other still remain constant but there are few hours where the St-Coal generation is displaced. The imports increase. This happens because the outside system is now at the same penetration at ISO-NE. The combined cycle generation is 60% of what it was with no wind generation.

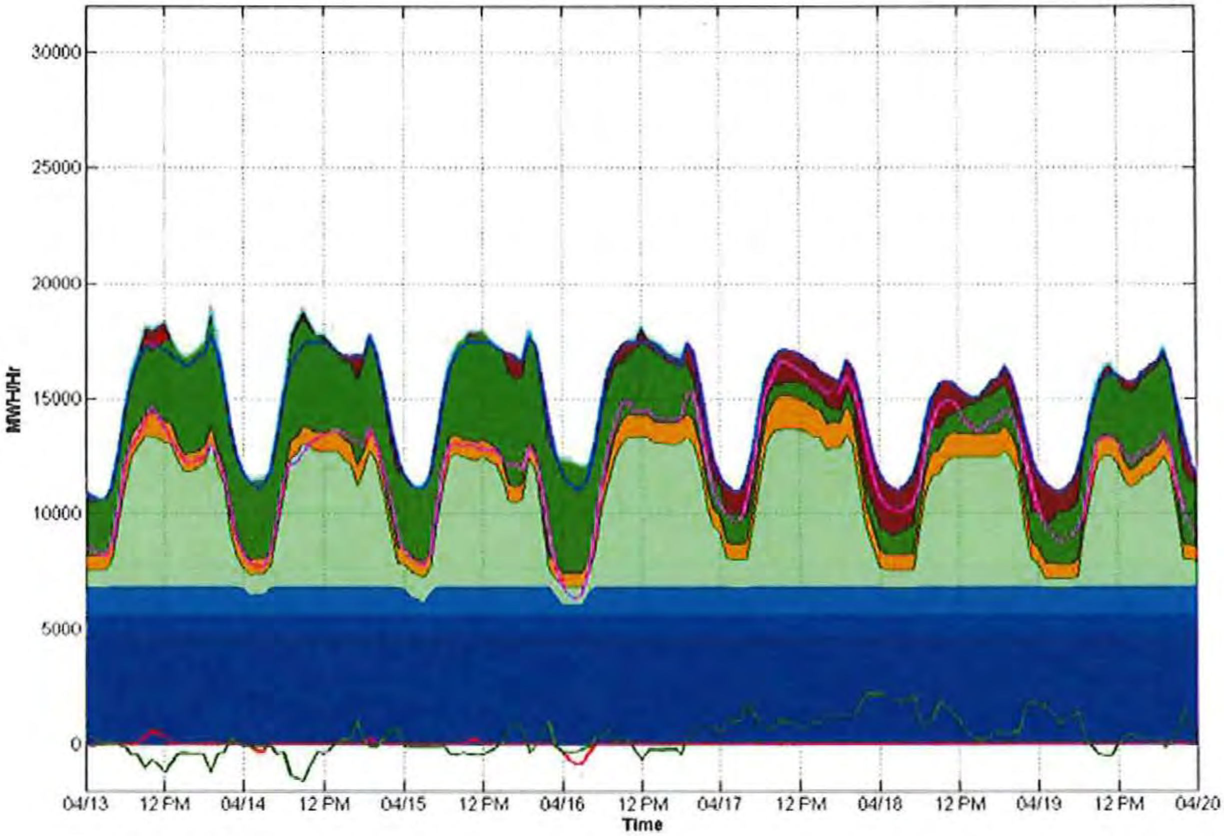


Figure 5–35 ISO-NE dispatch, week of April 13, 14% Energy_Best Sites Onshore, S-o-A forecast

Figure 5–36 shows how this operation changed for the 20% penetration level. The nuclear remain constant but there are few hours where the St-Other and St-Coal generation is displaced. There is a small increase in PSH operation. The combined cycle generation is 43% of what it was with no wind generation.

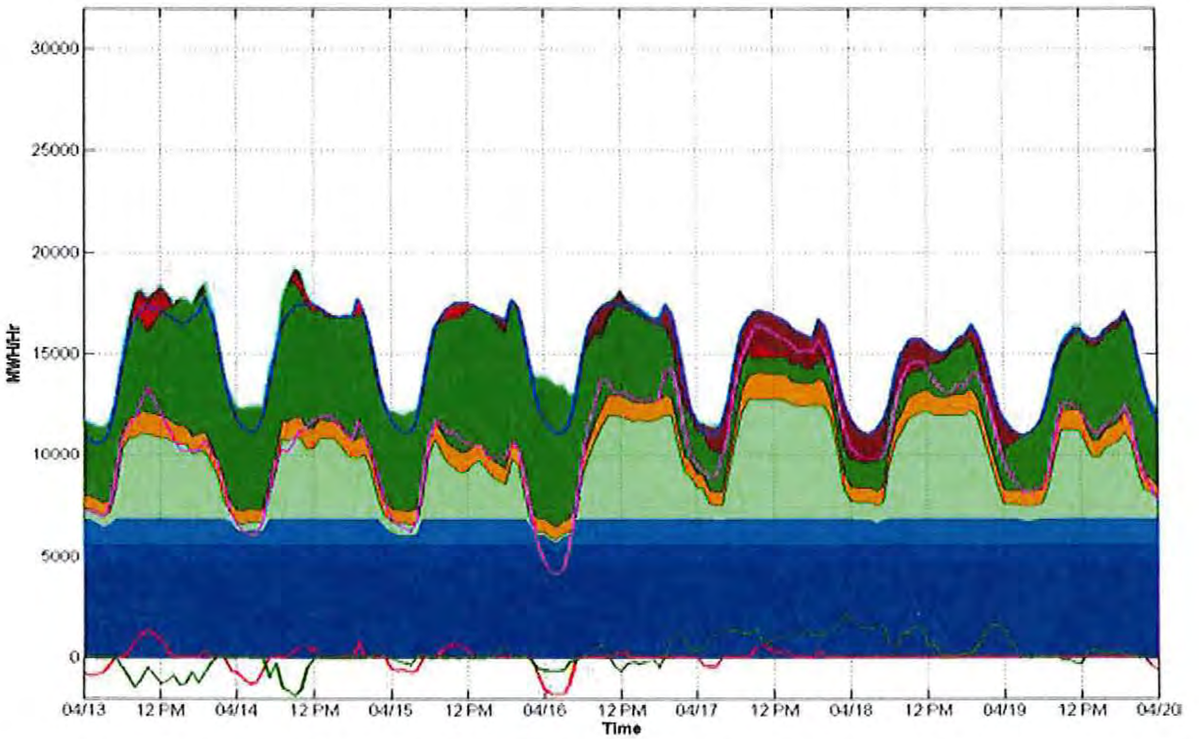


Figure 5–36 ISO-NE dispatch, week of April 13, 20% Energy_Best Sites Onshore, S-o-A forecast

Figure 5–37 shows how this operation changed for the 24% penetration level. This case is similar to the 20% except the combined cycle generation is 35% of what it was with no wind generation.

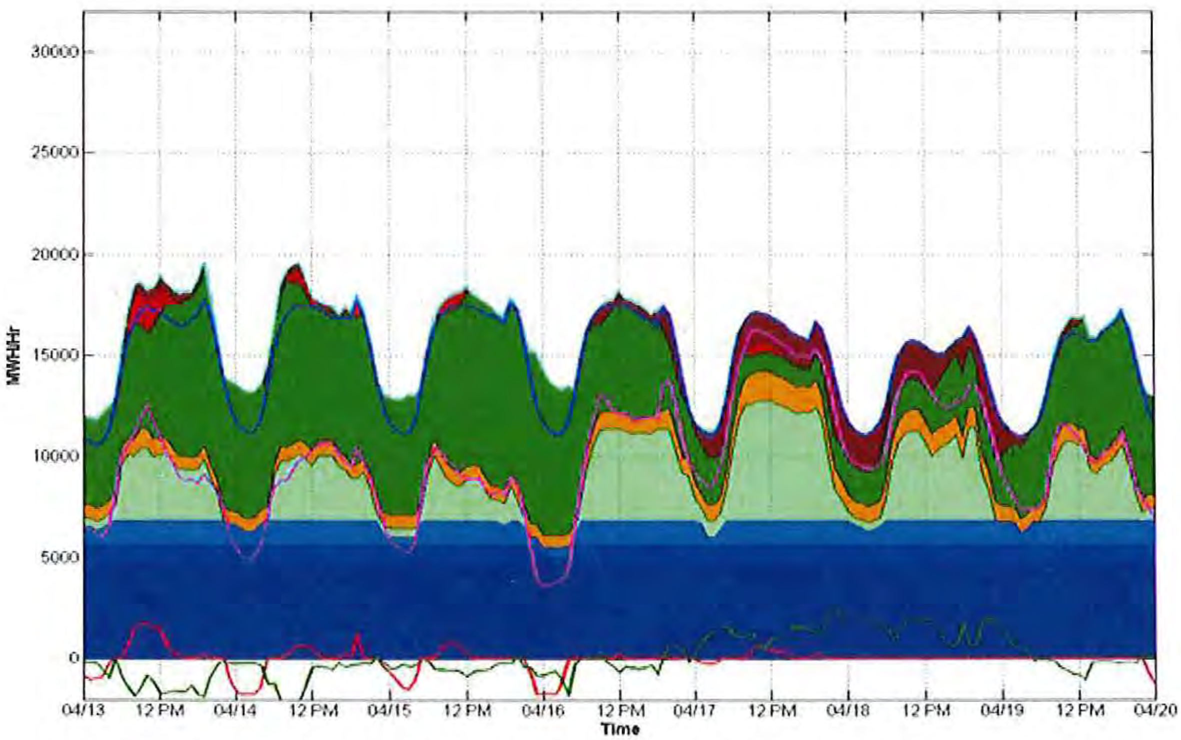


Figure 5–37 ISO-NE dispatch, week of April 13, 24% Energy_Best Sites Onshore, S-o-A forecast

Figure 5–38 through Figure 5–43 show the hourly operation by generation type for the week of July 6. Even at the 24% penetration level there is very little change in CC operation. The CC energy output has dropped by less than 20%. Most notable is the decrease in the gas turbine generation needed for peaking operation. It has been largely displaced by the wind generation.

A comparison of the series of figures for the April and July weeks shows that while high penetration of wind may cause significant changes in dispatch at certain times of the year, its impacts at other times will be much less severe. It may be that at low-load/high-wind times of the year more of the base load generation should be taken out of service to allow generators that are better able to cycle to provide the balance of the energy.

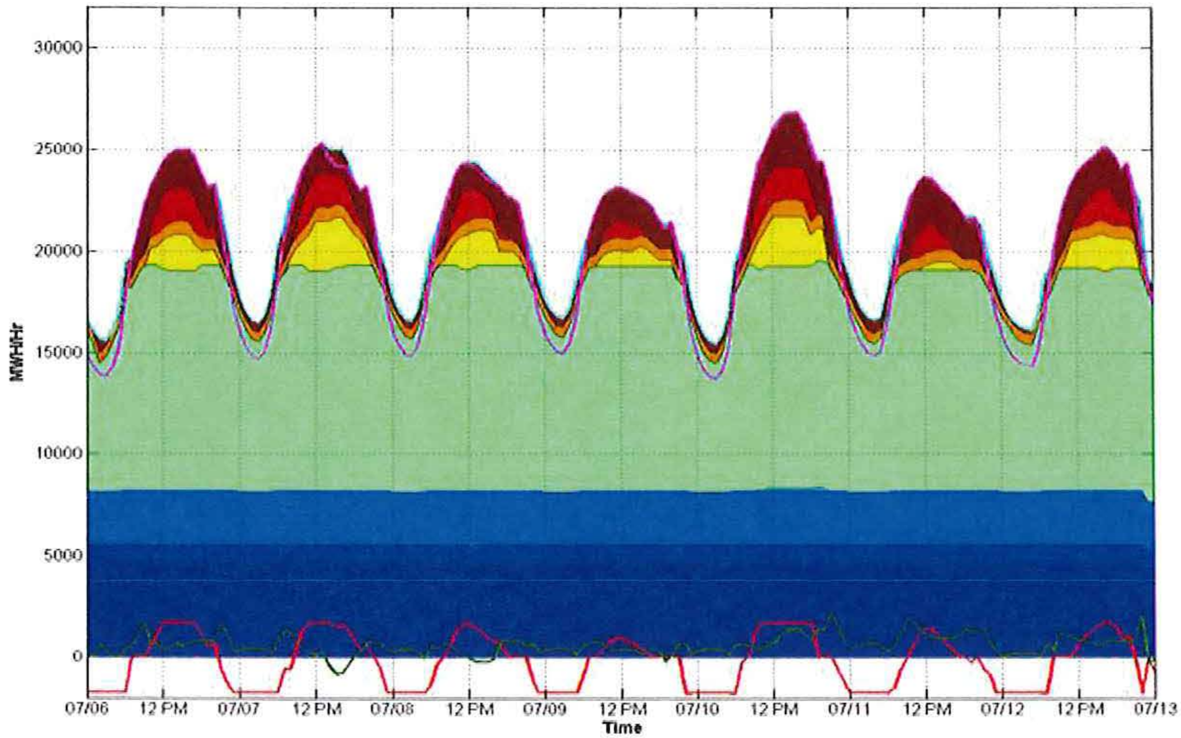


Figure 5–38 ISO-NE dispatch, week of July 6, no wind

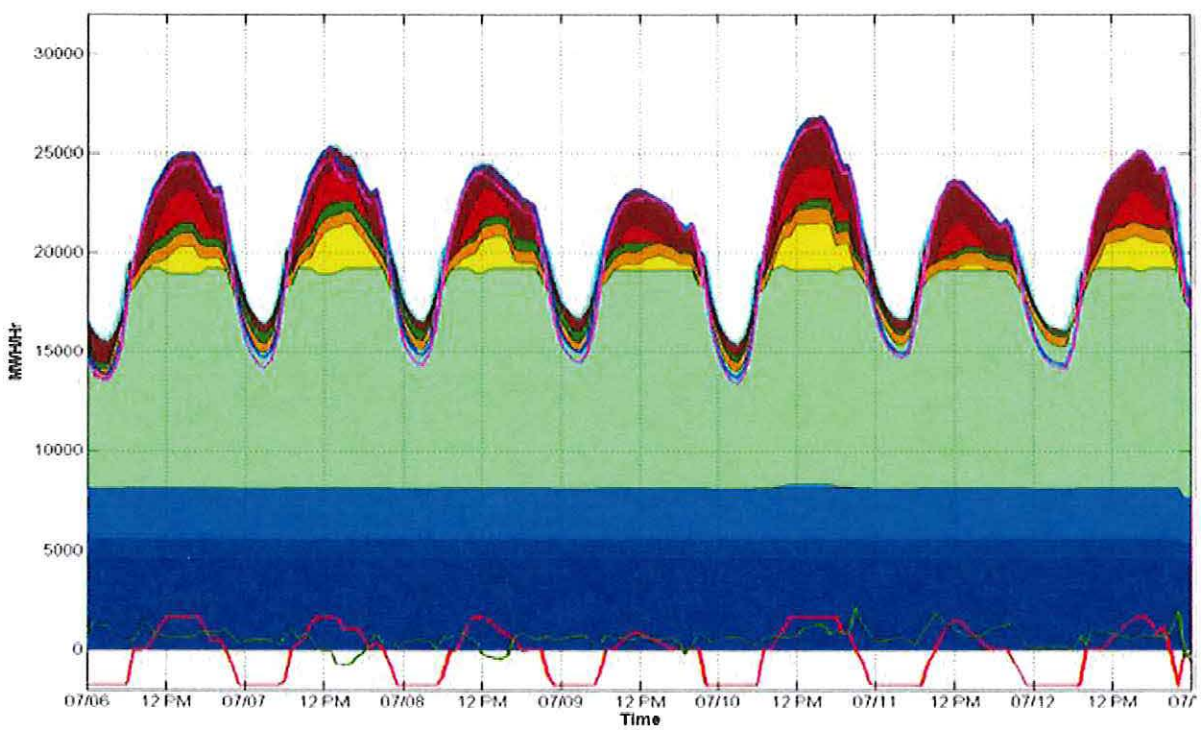


Figure 5–39 ISO-NE dispatch, week of July 6, 2.5% Energy, S-o-A forecast

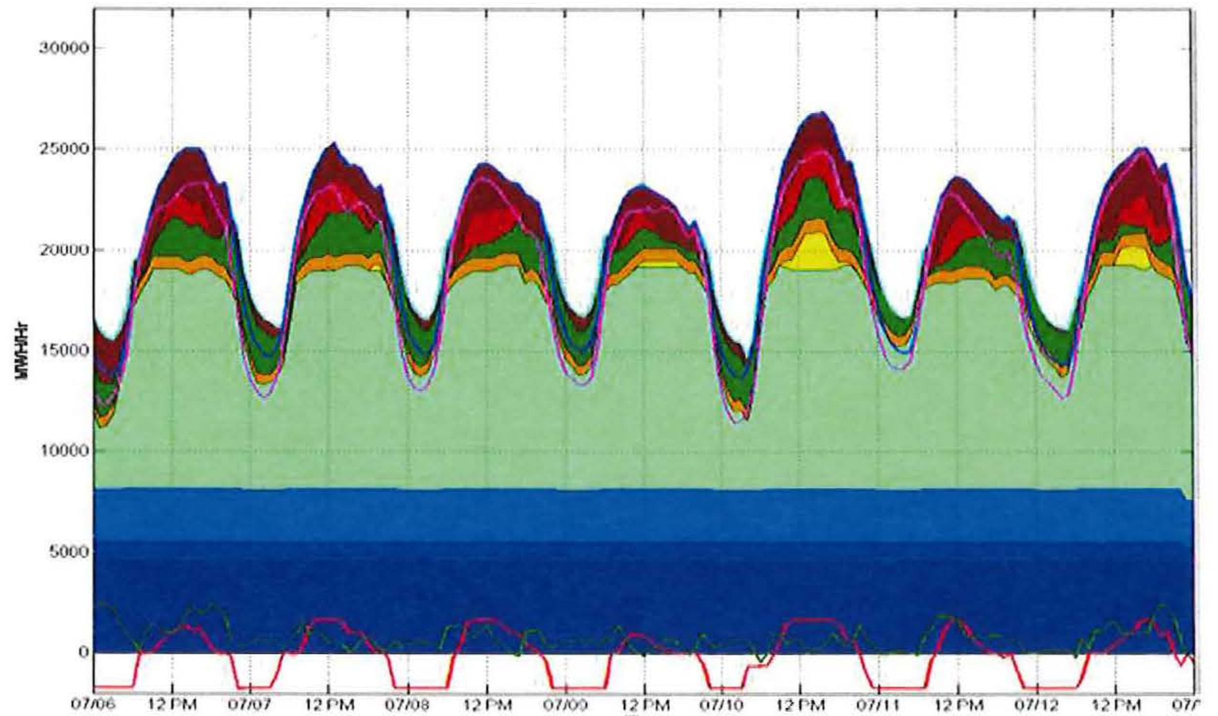


Figure 5–40 ISO-NE dispatch, week of July 6, 9% Energy, S-o-A forecast

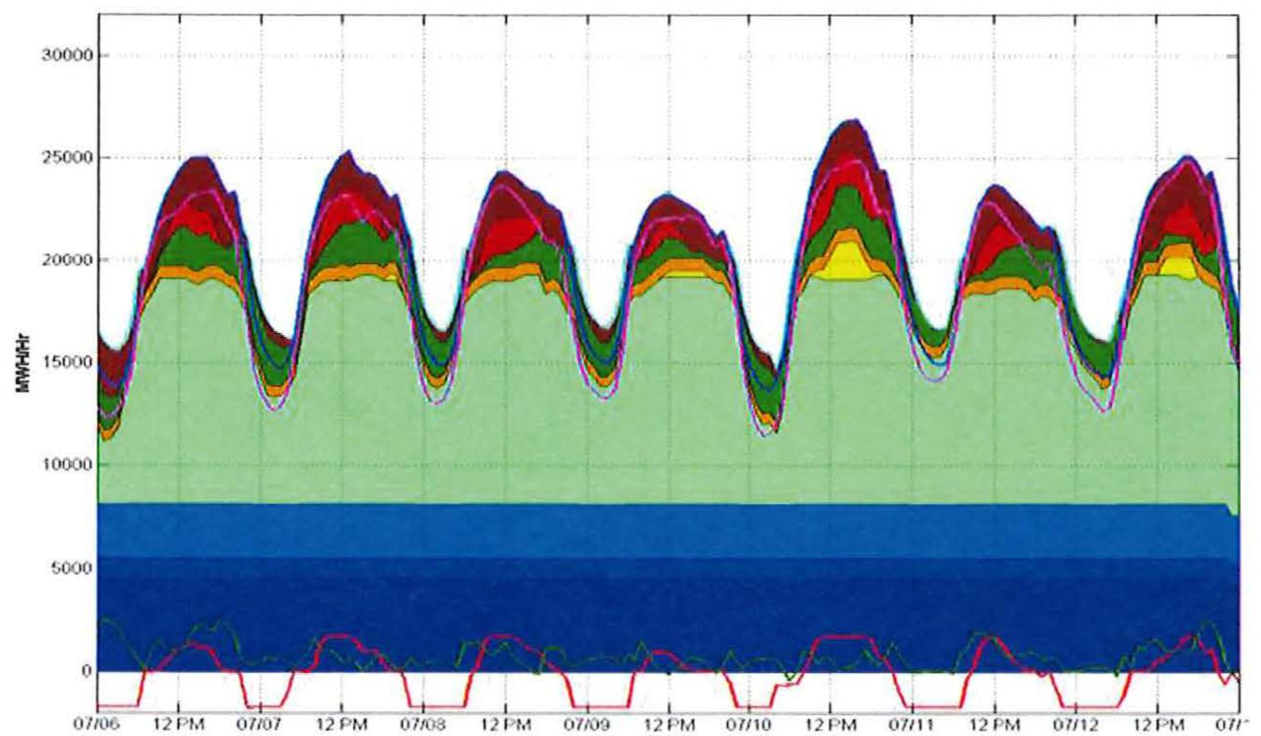


Figure 5–41 ISO-NE dispatch, week of July 6, 14% Energy_Best Sites Onshore, S-o-A forecast

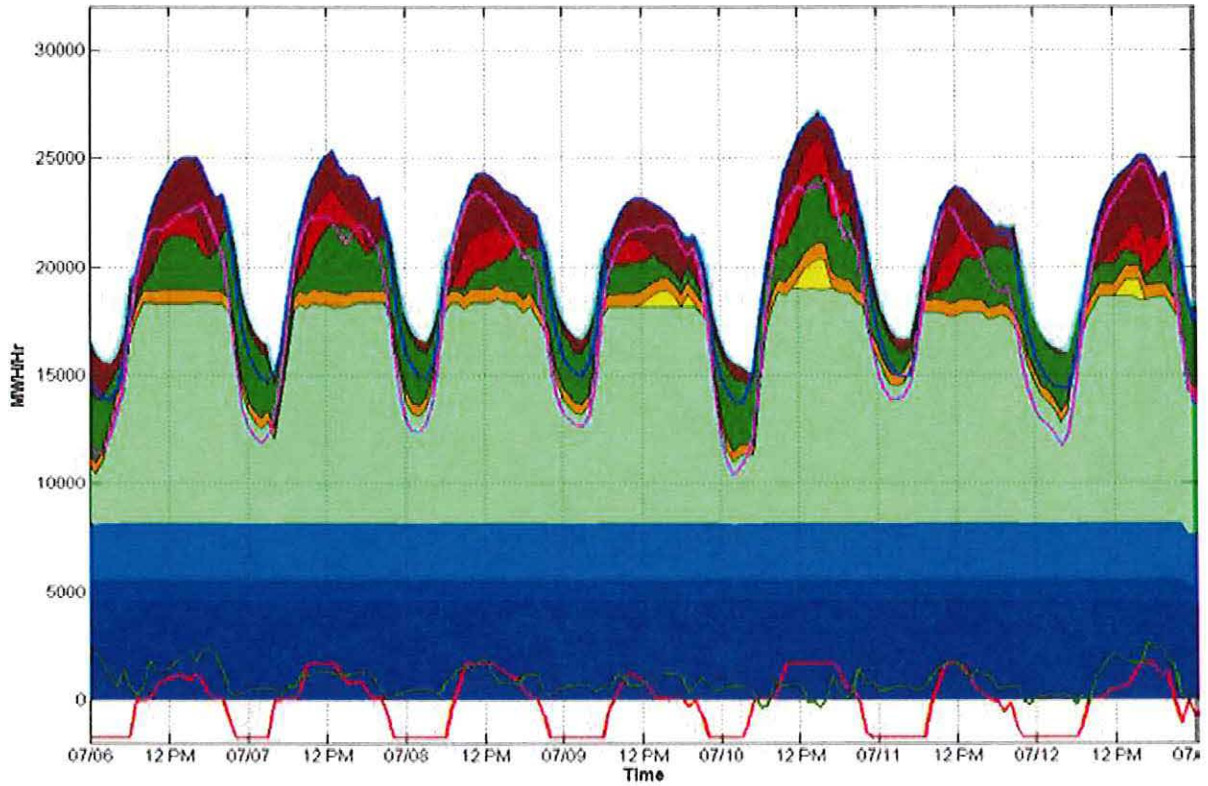


Figure 5–42 ISO-NE dispatch, week of July 6, 20% Energy_Best Sites Onshore, S-o-A forecast

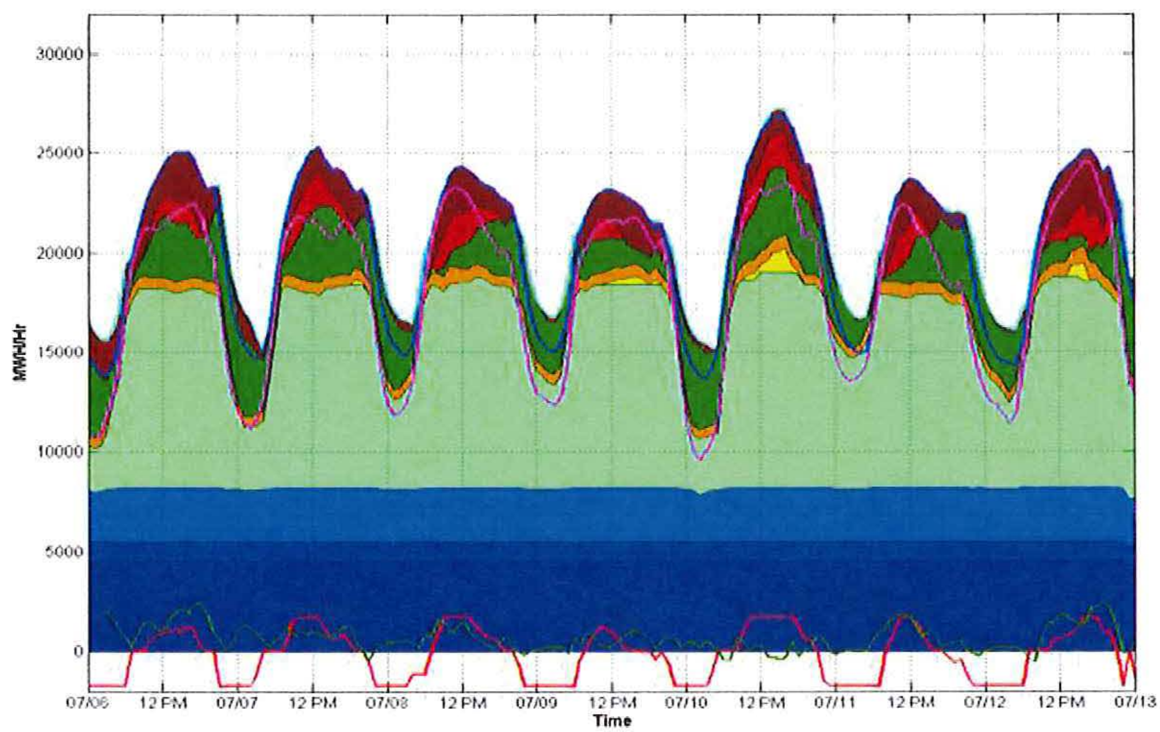


Figure 5–43 ISO-NE dispatch, week of July 6, 24% Energy_Best Sites Onshore, S-o-A forecast

Figure 5–44 through Figure 5–47 shows the range and ramp for a week in a spring month and summer month. The hourly results are similar to the annual duration charts. They show as the wind penetration increases, the range/ramp up available capacity increases and the range /ramp down available capacity decreases. The week in July has less variability between the different penetration levels because there is less wind online.

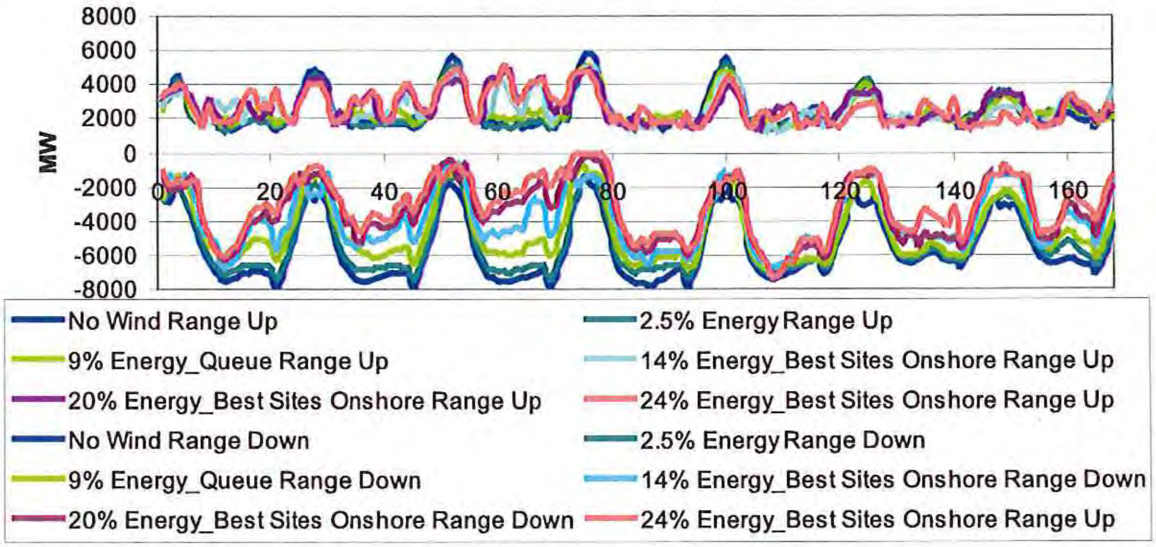


Figure 5–44 Range up/down capability week of April 13 S-o-A forecast, Best Sites Onshore

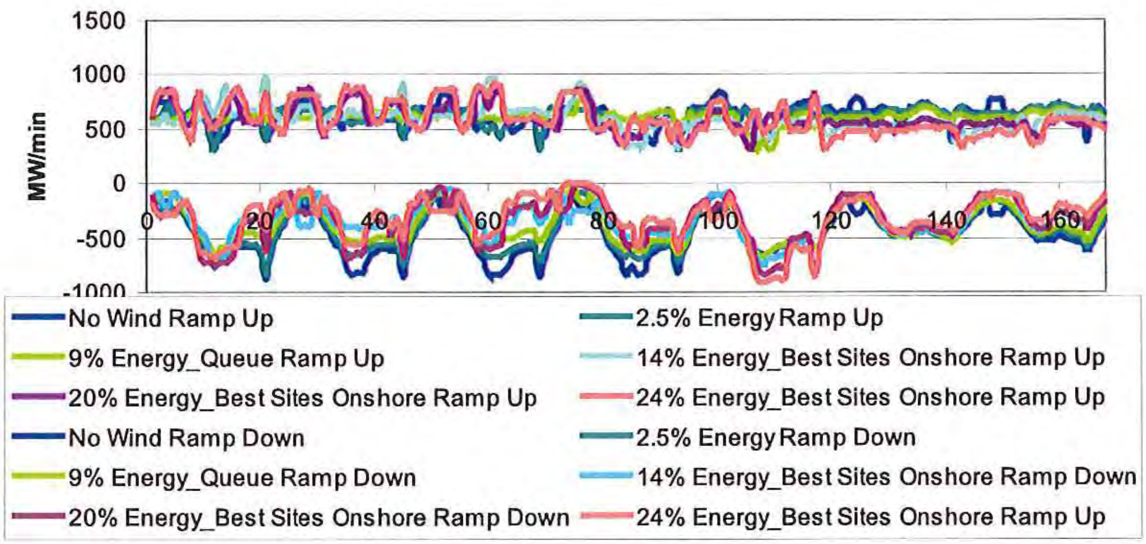


Figure 5–45 Ramp up/down capability week of April 13 S-o-A forecast, Best Sites Onshore

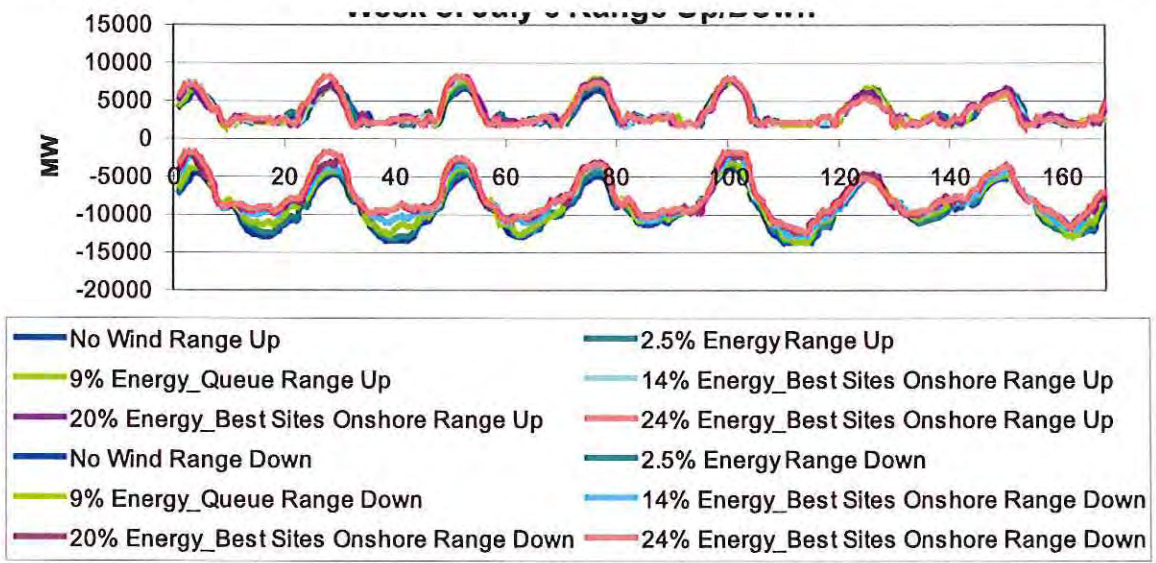


Figure 5–46 Range up/down capability week of July 6 S-o-A forecast, Best Sites Onshore

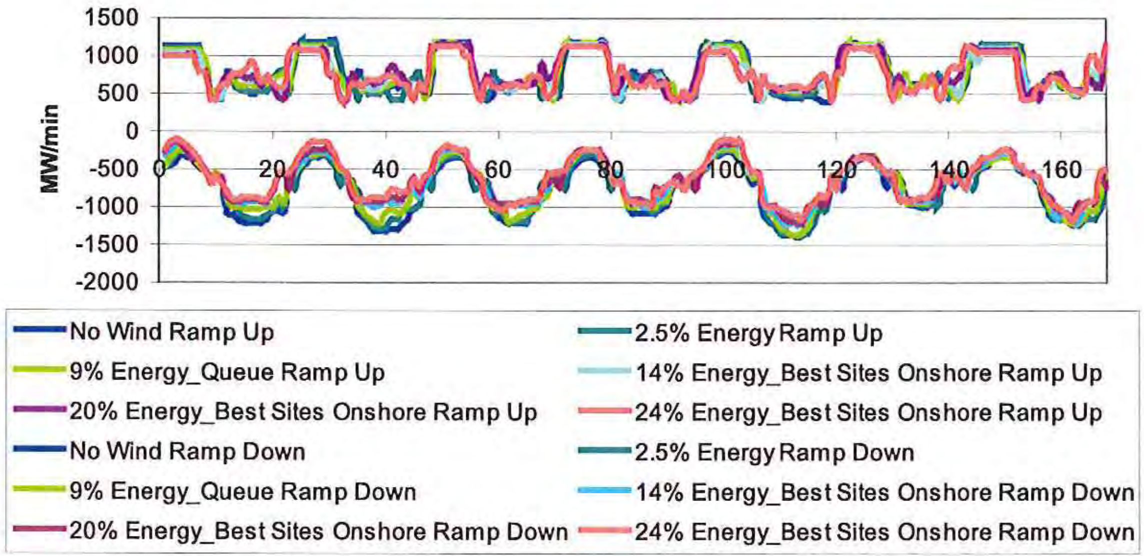


Figure 5–47 Ramp up/down capability week of July 6 S-o-A forecast, Best Sites Onshore

5.2.2 20% Wind Penetration

The following section compares the impact of 20% wind penetration on the ISO-NE system for the 5 different scenarios describes in Chapter 3. Note that the "Balance Case" is also referred to as the "Best Site" scenario. The results were done using 2006 load and wind shapes, an unbiased State-of-the-Art (S-o-A) day-ahead forecast of the wind generation and a constrained transmission system. Any variations will be noted.

Table 5–9 compares the total average three-year wind energy to the simulated wind using the 2006 shapes. There are slight differences by scenario as compared to the three-year average as well as slight differences between 2006 energy for the scenarios. These differences are minor though.

Table 5–9 20% penetration scenario comparison

Scenario	3 Year Average Wind Energy (GWh)	2006 Wind Energy (GWh)
20% Energy_Best Sites Onshore	29,060	28,882
20% Energy_Best Sites Offshore	29,060	29,494
20% Energy_Best Sites	29,060	29,222
20% Energy_Best Sites by State	29,060	29,212
20% Energy_Best Sites Maritimes	29,060	28,639

Although each of the five scenarios are made up of different sites overall, the wind pattern is similar across them. Figure 5–48 compares the wind energy by 20% scenario on a monthly basis. Although the annual energy is very similar for all the scenarios, the monthly energy has some variation. For example, in March the 20% Energy_Best Sites Maritimes has the lowest monthly energy produced, but in December it has the greatest out of the five. Although the maintenance was held constant for all the scenarios, the maintenance will interact with the wind generation. For example if a large unit is out in May, different units may be displaced in the various scenarios depending on the wind profile. Therefore depending on the load and the maintenance, each scenario will produce different results.

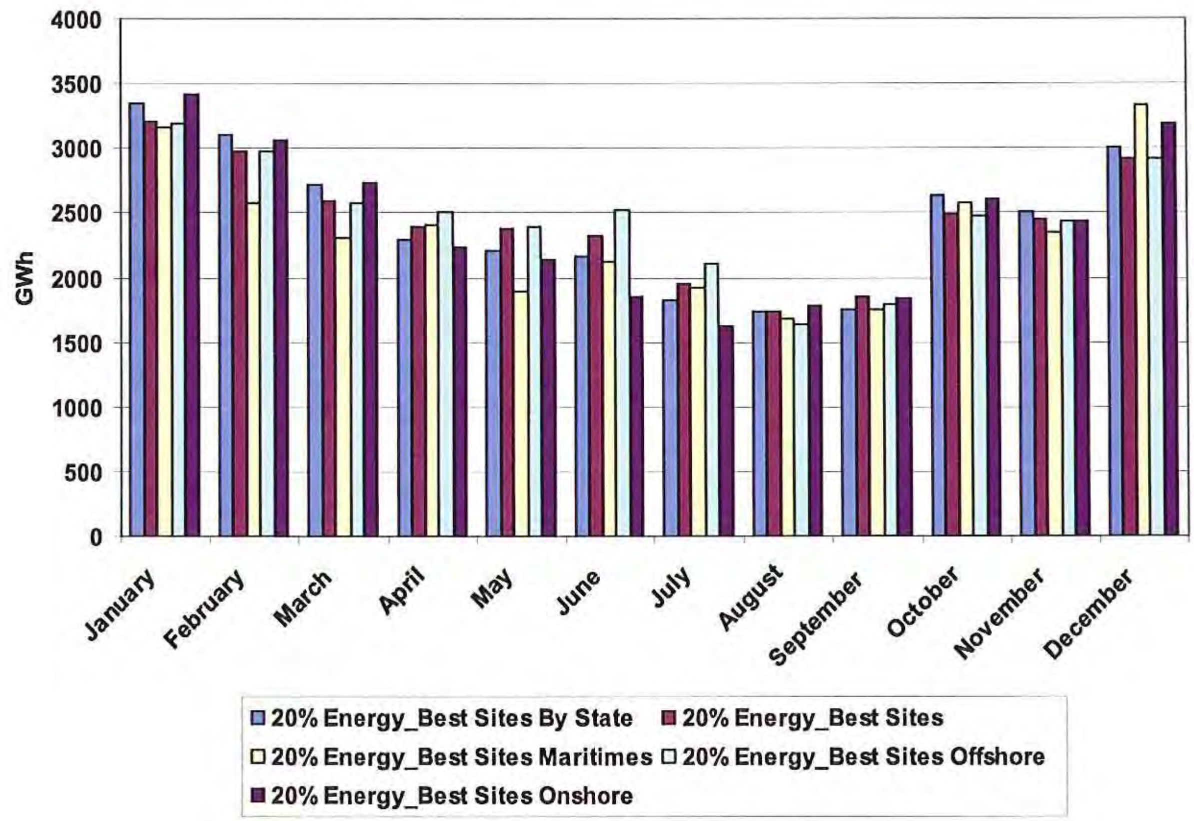


Figure 5–48 20% Scenarios Monthly Energy Summary

Figure 5–49 illustrates the hourly wind generation for the month of April and July for each of the scenarios. These months were highlighted to show a spring and summer month. Overall the shapes are similar for the scenarios.

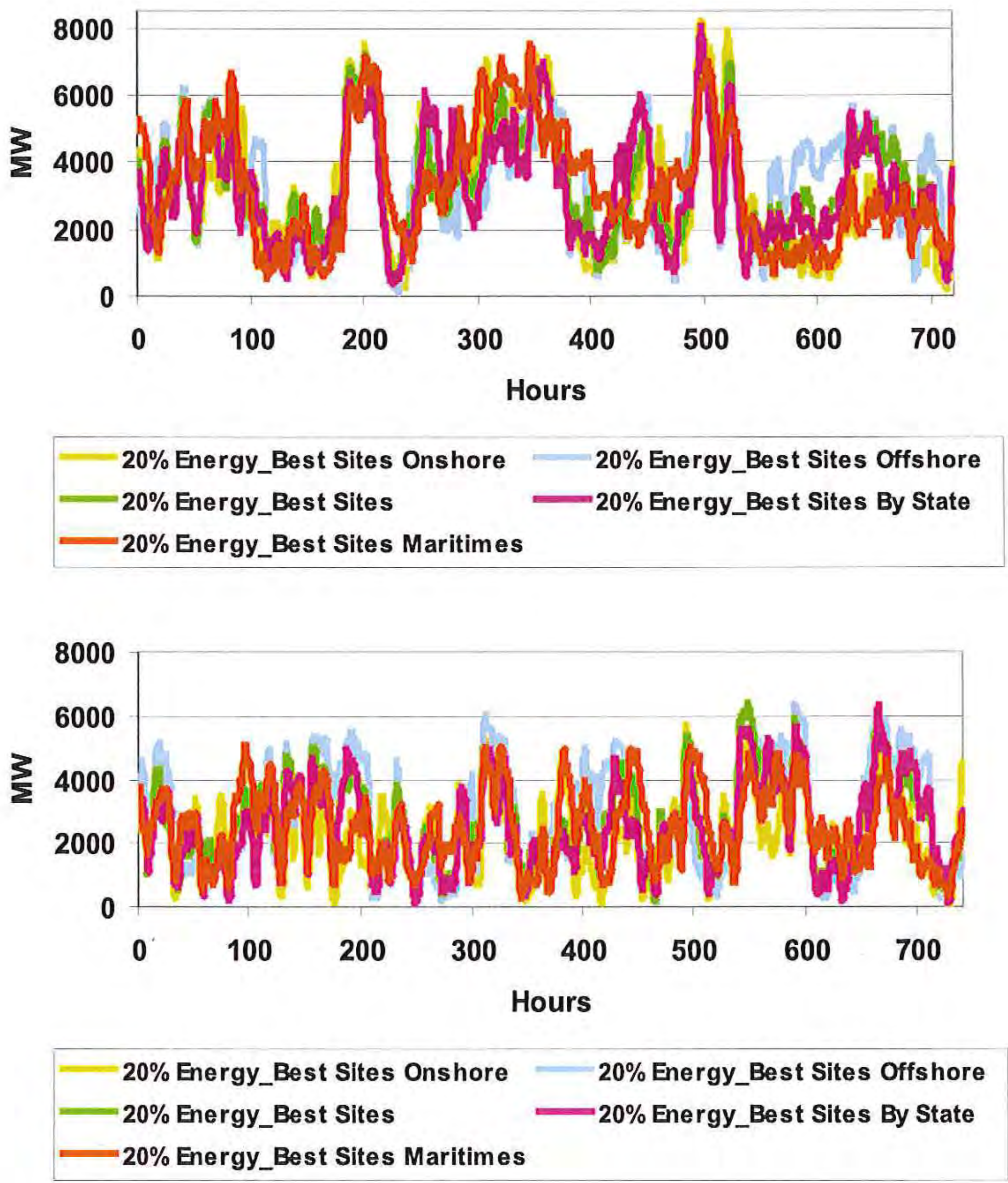


Figure 5–49 April and July hourly wind generation, 20% wind penetration

Figure 5–50 compares the annual average load weighted ISO-NE LMP for the five different constrained 20% penetration scenarios. It also includes the No Wind Scenario. The No Wind Scenario removed all wind from the modeled system. This was done for comparison purposes. It allows the overall impact of the wind penetration to be determined. The average LMP for the No Wind Scenario was approximately $61/MWh. The 20% Energy_Best Sites By State had the largest reduction and the 20% Energy_Best Sites Maritimes had the smallest reduction. Overall the reduction of LMP by introducing 20% wind penetration into ISO-NE ranged from $5/MWh to $11/MWh.

The overall impact of 20% wind penetration is relatively small on the annual average LMP as compared to No wind case. Wind energy helps to reduce some high priced hours, but most of the impact is during the off peak times. During these hours gas is on the margin and is displaced by the wind. The wind does not cause a large shift from gas to coal, which will be shown later in this chapter, leaving gas still on the margin. This has a small impact on the LMP.

There are slight variations between the different scenarios. Overall the location of the wind has a small impact on the overall result.

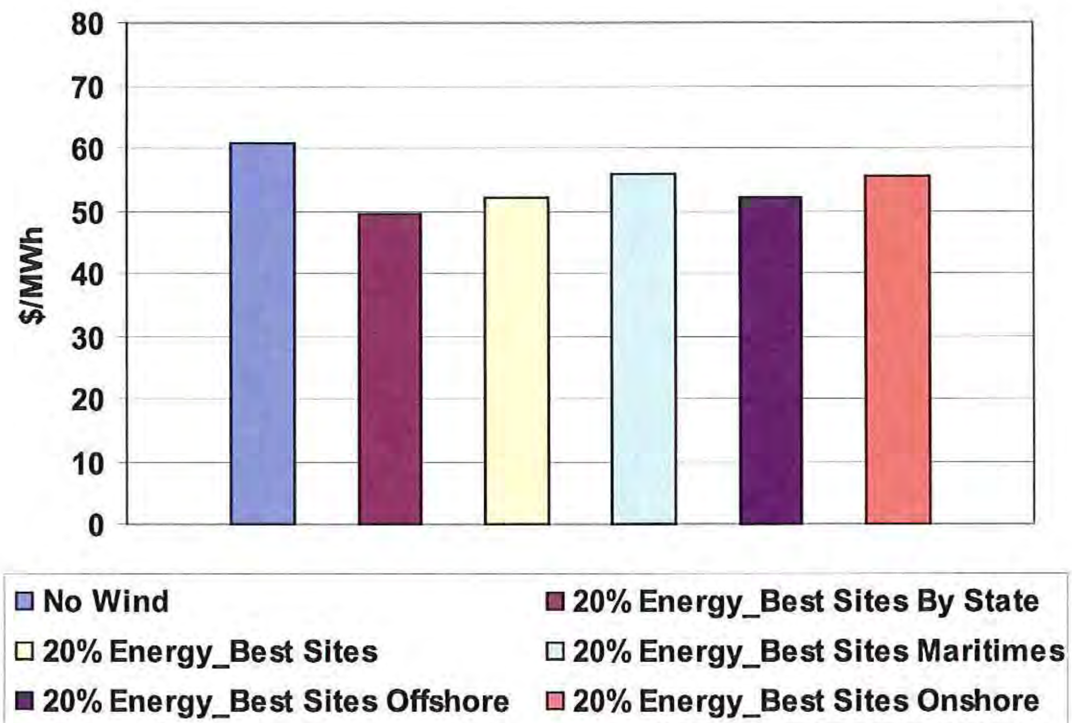


Figure 5–50 Annual load weighted average ISO-NE locational marginal price, S-o-A Forecast, 20% penetration

Figure 5–51 shows the RSP zonal load weighted annual average LMP. There is some slight variation in the No Wind Scenario. The prices are relatively flat across the RSP zones for each of the 20% scenarios. This indicates that the Governors' 4 GW overlay is sufficiently built to eliminate transmission congestion and handle 20% penetration of wind. More details will be presented on the impacts of transmission later in this section.

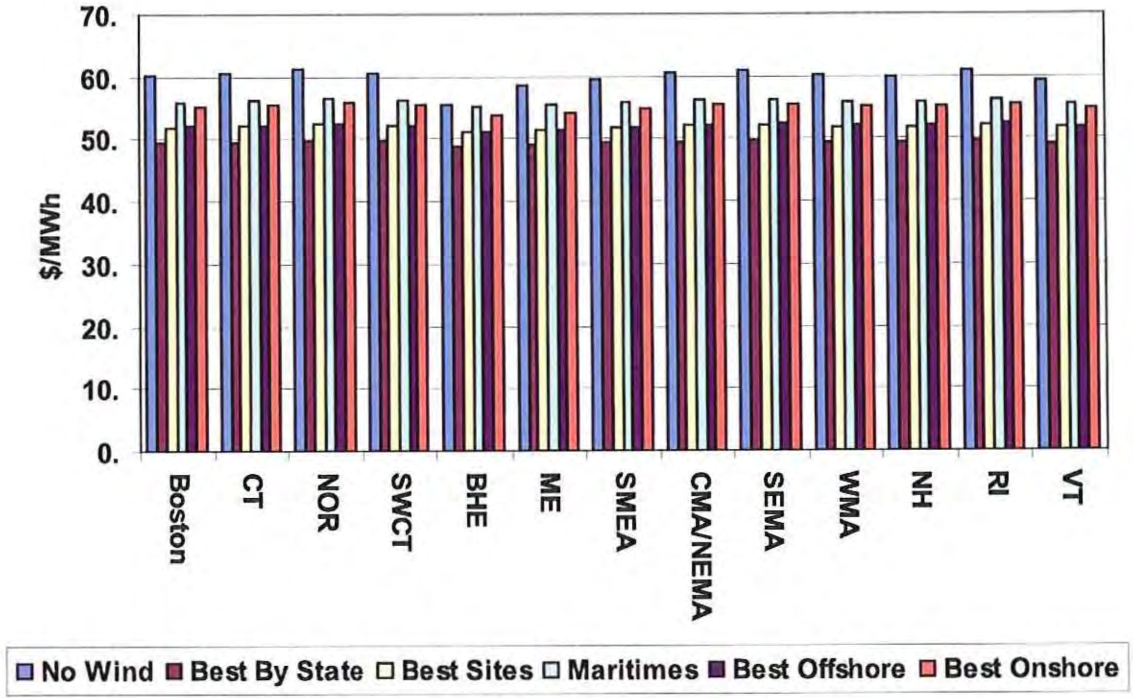


Figure 5–51 Annual load weighted average ISO-NE RSP locational marginal price, S-o-A Forecast, 20% penetration

Figure 5–52 shows No Wind and 20% Energy_Best Sites Onshore scenarios RSP zonal load weighted annual average LMP. The zonal price variations can be seen more clearly. There are some slight variations in the 20% Energy_Best Sites Onshore scenarios, but the magnitude is much smaller than the No Wind scenario. This occurs because the transmission system is expanded from the ISO-NE 2019 system in the No wind Scenario to the Governors' 4 GW overlay in the 20% Energy scenarios, reducing transmission congestion between RSP zones.

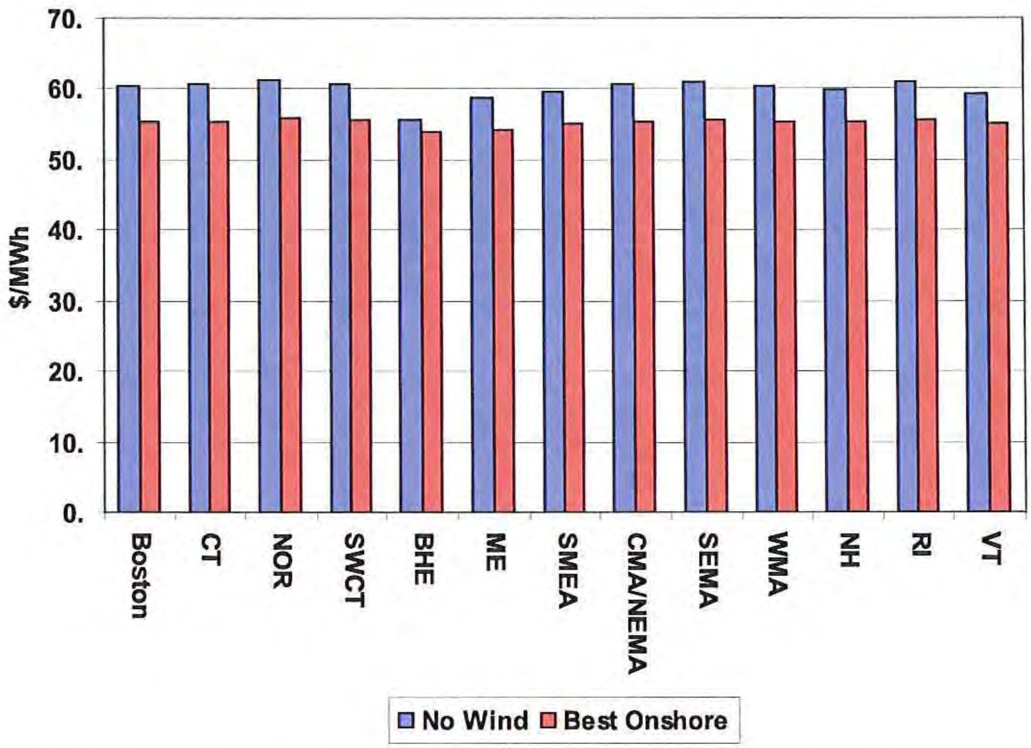


Figure 5–52 **Annual load weighted average ISO-NE RSP locational marginal price, S-o-A Forecast, 20% penetration No wind, Best Onshore**

Figure 5–53 shows the hourly duration LMP that corresponds to Figure 5–50. These were calculated chronologically for each hour of the year for each scenario. They were then sorted for easy comparison of the overall impacts. The first plot is for the full 8784 hours of the year. The following plots zoom in on the highest/lowest 1000 hours.

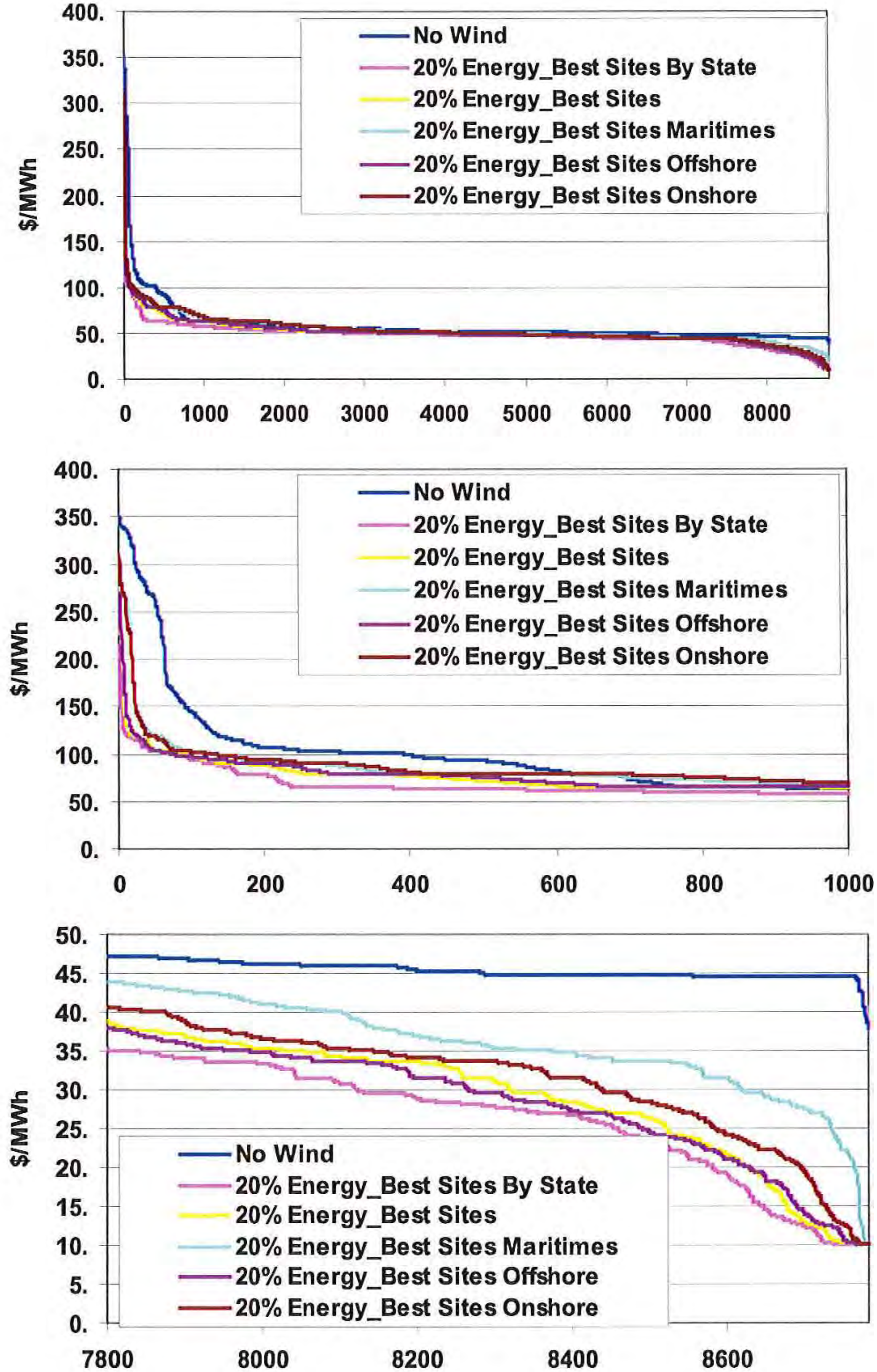


Figure 5–53 Annual LMP duration curve, S-O-A Forecast, 20% penetration

With no wind generation on the system, the LMP ranges from a high of approximately \$350/MWh to a low of about \$38/MWh. All of the 20% penetration scenarios have similar impacts on the spot price. Introducing 20% penetration of wind to the system reduces the highest cost to about \$300/MWh and the lowest to about \$10/MWh. As described in section 5.2.1, the \$10/MWh price is based on the wind dispatch cost during these hours; the wind was curtailed to not allow it to displace nuclear generation. This would be classified as minimum generation events. The most this occurs is 34 hours. This equates to approximately 0.4% of the year. As mentioned earlier in the chapter, negative bids were not modeled and therefore the LMP never goes negative.

Curtailment can be caused by mainly three issues: transmission congestion, minimum generation events where nuclear is on the margin, and minimum generation events due to the under forecasting of wind. Under forecasting can lead to excess thermal generation being committed which can lead to minimum operating constraints. A discussion on the forecast error by penetration and scenario can be found in Chapter 3. Table 5–10 summarizes the total curtailment for the 20% Energy scenarios. It also shows the percentage of curtailed wind to the total wind energy for the scenario. The curtailment is relatively low. The 20% Energy Best Sites Offshore had the smallest amount of curtailment.

Table 5–10 Wind Curtailment 20% Energy

Scenario	Curtailment (GWh)	% Total Energy
20% Energy_Best Sites Onshore	27.12	0.09%
20% Energy_Best Sites Offshore	16.23	0.06%
20% Energy_Best Sites	29.55	0.10%
20% Energy_Best Sites by State	60.33	0.21%
20% Energy_Best Sites Maritimes	328.65	1.15%

AS can be seen in the table the 20% Energy Best Sites Maritimes had the most curtailment. 1.15% of the total wind energy for the scenario was curtailed. There were roughly 4.8 GWs of wind added to the Maritimes in addition to the full queue. The transmission system in the Governors' 4 GW overlay included the addition of a 1,500 MW HVDC cable from the Maritimes to the ISO-NE. This expanded the import capability into ISO-NE to about 3000 MW including the new connections to Northern Maine. Therefore, when the wind production was higher than this it would be used to displace Maritimes units or be curtailed.

Figure 5–54 shows the total generation by type for ISO-NE for the 20% penetration scenarios. The bulk of the energy that is displaced by the wind generation as compared to the No Wind Scenario is coming from CC units with some slight variations in GT, PSH, and St-Coal units. There are also slight variations in imports from HQ imports and Imp_Exp. One thing to note is that the wind that is imported from the Maritimes in the 20% Energy_Best Sites Maritimes is not included in the Imp_Exp. This energy is included the Wind category.

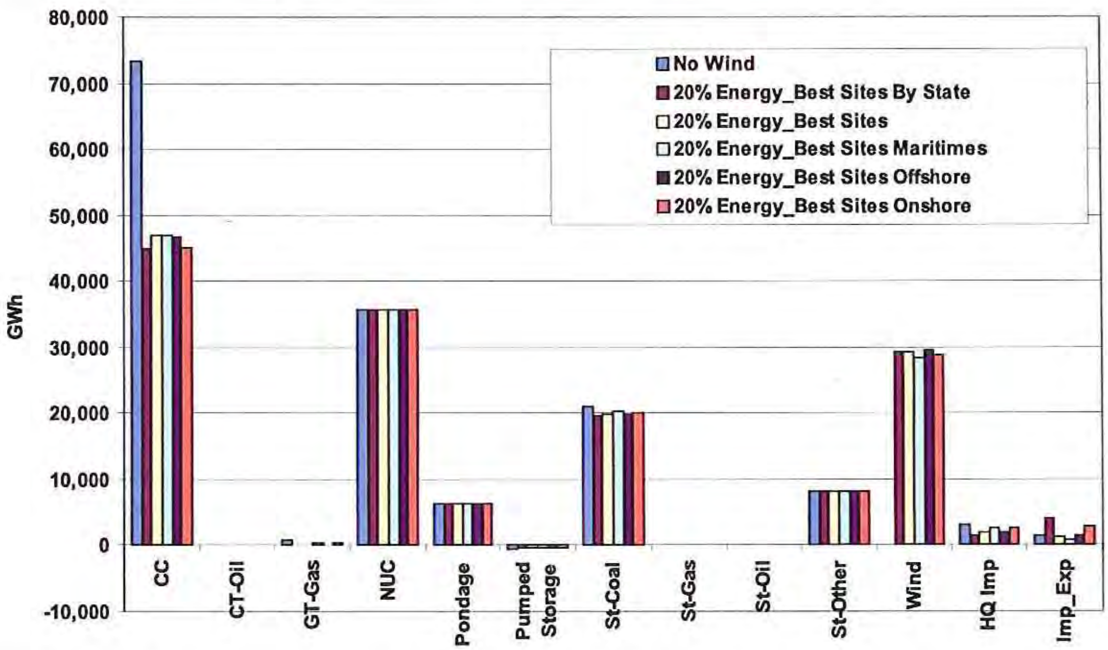


Figure 5–54 ISO-NE generation by type, S-o-A forecast, 20% penetration

It is not a surprise that most of the displacement is in CC generation for ISO-NE. Figure 5–55 is a dispatch stack, for ISO-NE system, for the year 2020. A dispatch stack, stacks the generator's calculated full load variable cost (Fuel Cost, Variable O&M, Start up Cost, Emission Cost) on a $/MWh basis from the lowest cost generation to the highest cost. The stack assumes 100% of the conventional generation is available. This provides a simple way to determine what type of generator would be on the margin depending on various load levels. The blue lines represent peak, median, and minimum load only values for 2020. The orange lines represent the net load values. The median and net median load occurs in the CC range. As can be seen in the figure, CCs would be on the margin most hours.

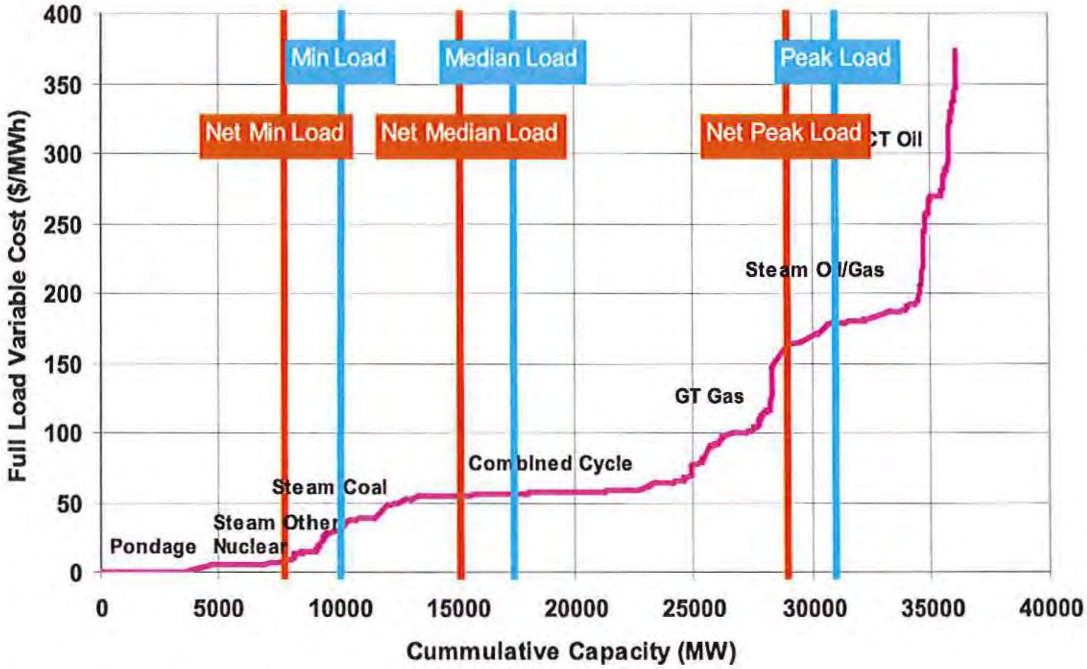


Figure 5–55 2020 ISO-NE dispatch stack

Figure 5–56 shows the hourly duration curve for the pumped storage hydro operation in ISO-NE for the No Wind and the five 20% wind penetration scenarios.

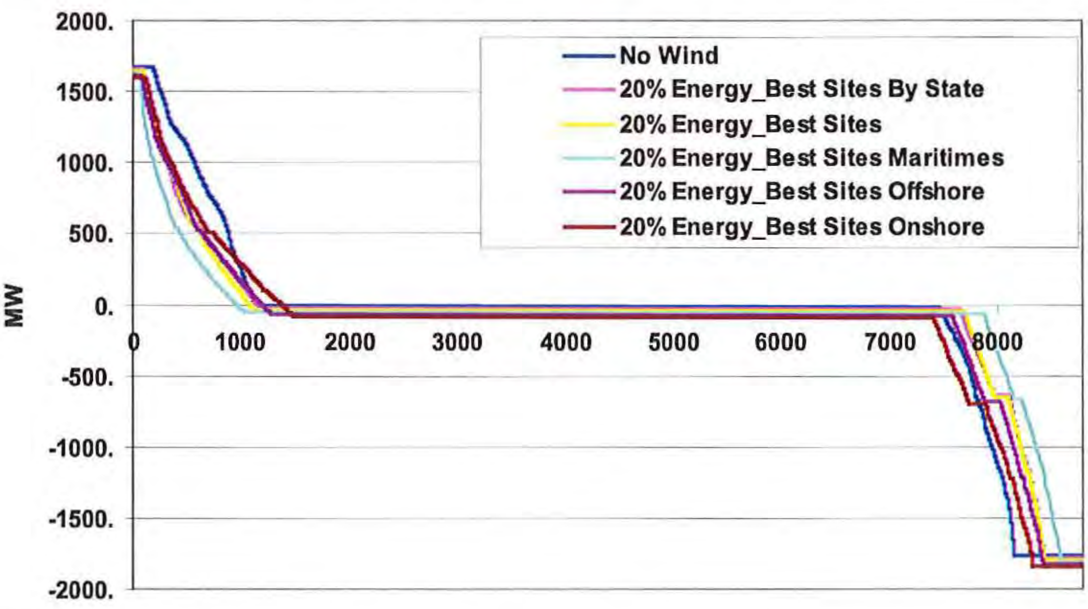


Figure 5–56 ISO-NE Pumped Storage Hydro Operation, S-o-A forecast, 20% penetration

With increased wind penetration, many believe more storage will be needed. It is important to look at how the existing storage changes with increased wind penetration. As can be seen in the figure, the operation is similar for the different wind penetration scenarios and does not vary much from the No Wind Scenario. As described in the previous section, gas is on the margin most hours even with the addition of wind generation, therefore only resulting in a large enough on-peak/off-peak price differential to warrant small changes in PSH operation.

Figure 5–57 shows the total emission for the 20% penetration scenarios as compared to the No Wind Scenario and Figure 5–58 shows the reduction relative to the No Wind scenario. The reduction is similar for all the 20% scenarios.

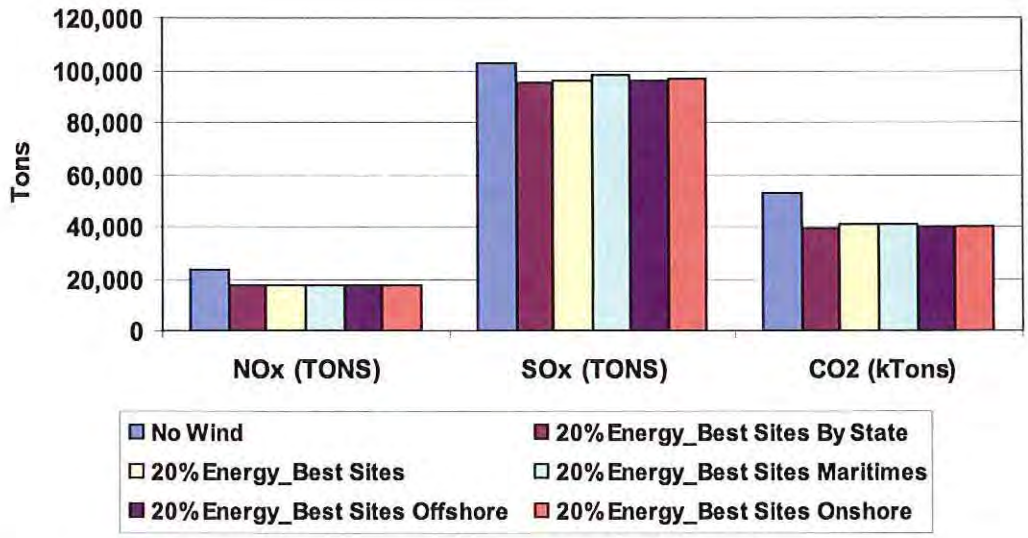


Figure 5–57 ISO-NE Total Emissions, S-o-A forecast, 20% penetration

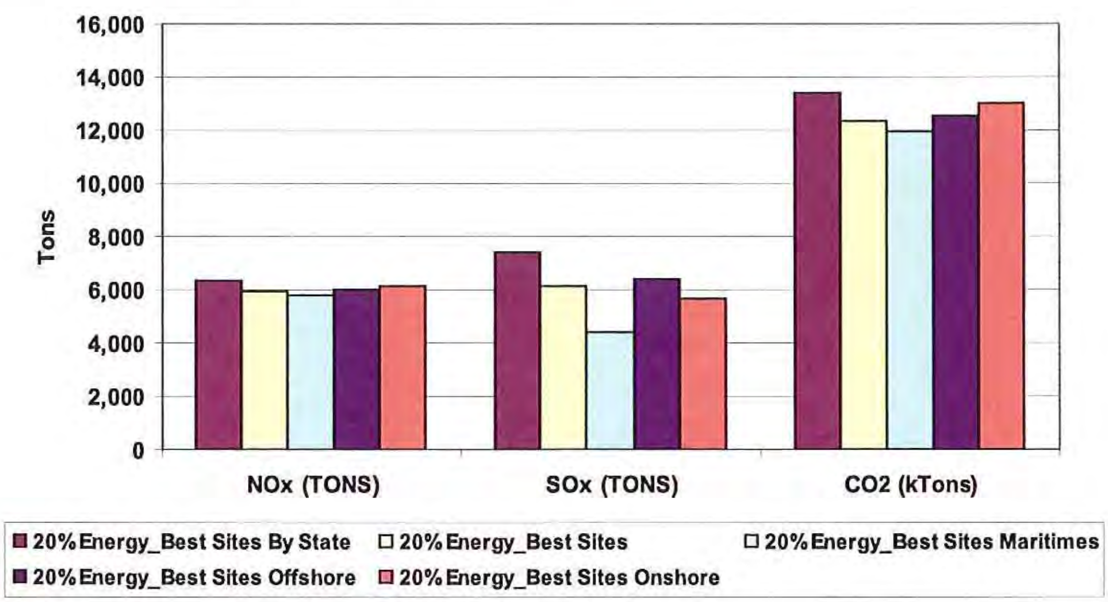


Figure 5–58 ISO-NE Total emissions reduction, S-o-A forecast, 20% penetration

The average reduction 20% wind penetration was approximately: NOx 6,000 tons or 26%, SOx 6,000 tons or 6%, and CO2 was reduced by 13million tons or 25%. The 25% reduction in CO2 with 20% wind penetration results from the fact that roughly 65% of the ISO-NE generation produces CO2. 25% of the generation that produces CO2 is being displaced.

There are slight variations in the reduction for the different scenarios. For example, the SOx reduction is the smallest in the 20% Energy_Best By Maritimes scenario. This is because the coal operation had the smallest reduction as seen in Figure 5–54.

Figure 5–59 compares the emission reduction per MWh of ISO-NE of wind generation. This was calculated for each scenario by dividing total emission reduction relative to the No Wind Scenario by the total energy produced by ISO-NE wind generation in that scenario.

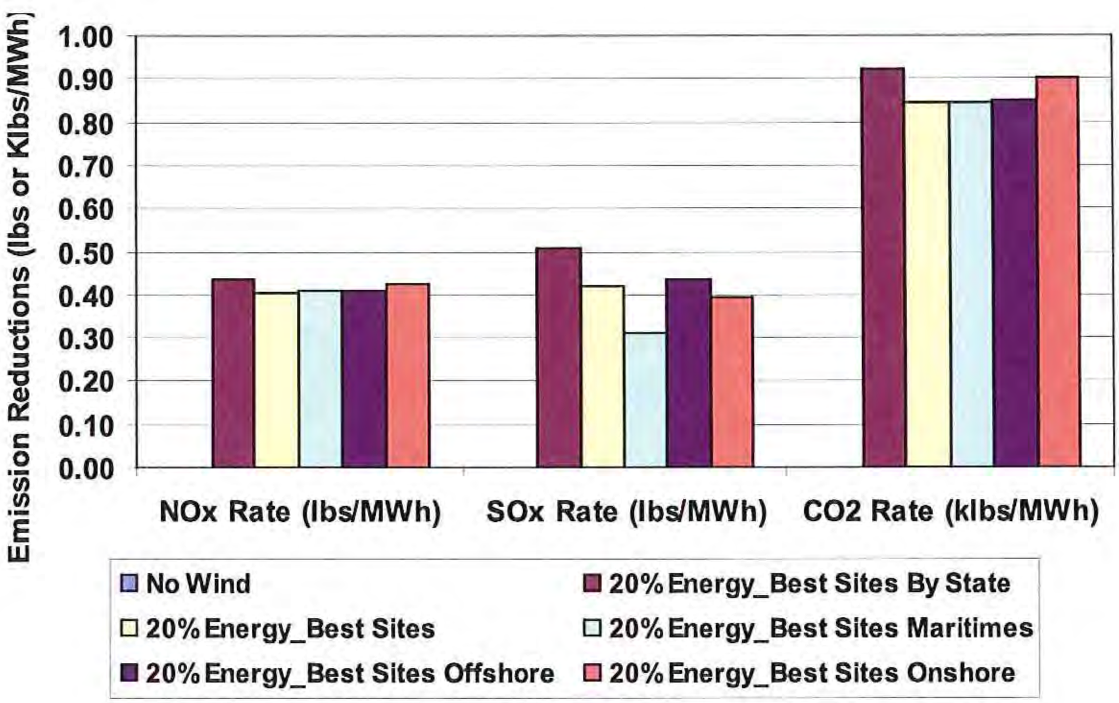


Figure 5–59 ISO-NE total emission reduction per MWh of wind generation, S-o-A forecast, 20% penetration

Figure 5–60 shows the total revenue received by each generation type. The revenue is calculated by taking the sum of the hourly LMP times the hourly generation. The revenue is reduced for all the non-wind generation. This is not only due to the lower LMP but also the displacement of generation caused by the wind energy. As expected the CC generation sees the largest reduction in revenue.

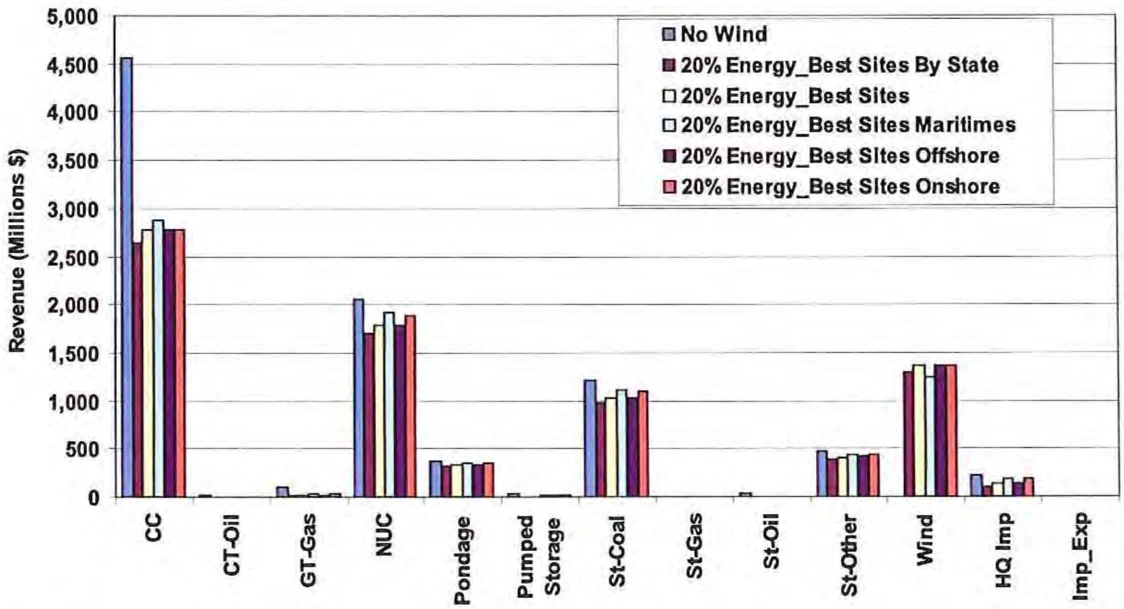


Figure 5–60 ISO-NE revenue by type, S-o-A forecast, 20% penetration

Figure 5–61 looks at the revenue and operating cost reduction per MWh of wind relative to the No Wind Scenario for CC and St-Coal generation. The operating cost reduction is a result of less operation due to the wind penetration and the revenue reduction is from a combination of reduction in operation and a lower LMP. The delta between the two is the net profit reduction due to the wind. Taking a closer look at the CCs for the 20% Energy_Best Sites Onshore case, the operating cost reduction was about \$54/MWh and the revenue reduction was about \$61/MWh. This is a net profit reduction of \$7/MWh for CC's per MWh of wind. St-Coal for the same case had net profit reduction of about \$3 per MWh of wind. This is less than the CCs because ST coal had substantially less displacement than the CCs. Figure 5–62 shows the same data as Figure 5–61 except it is in % relative to the No Wind Scenario.

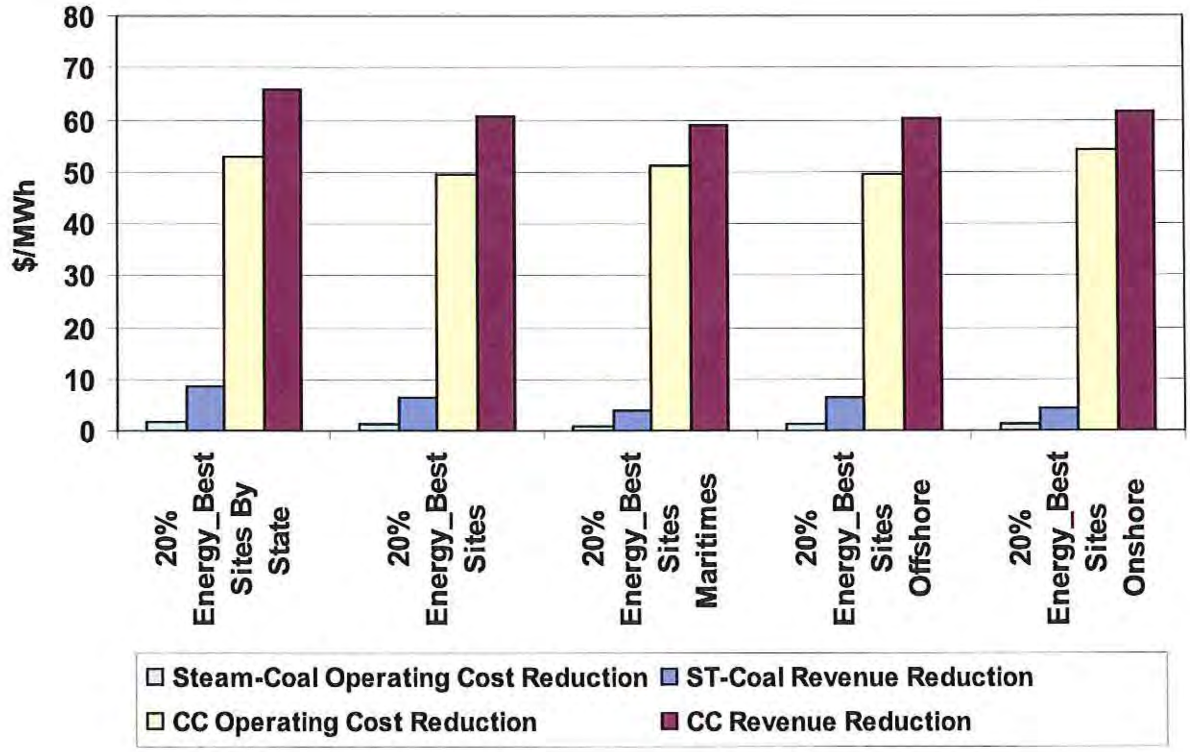


Figure 5–61 ISO-NE CC and St-Coal revenue and operating cost reduction per MWh of wind generation, S-o-A forecast, 20% penetration

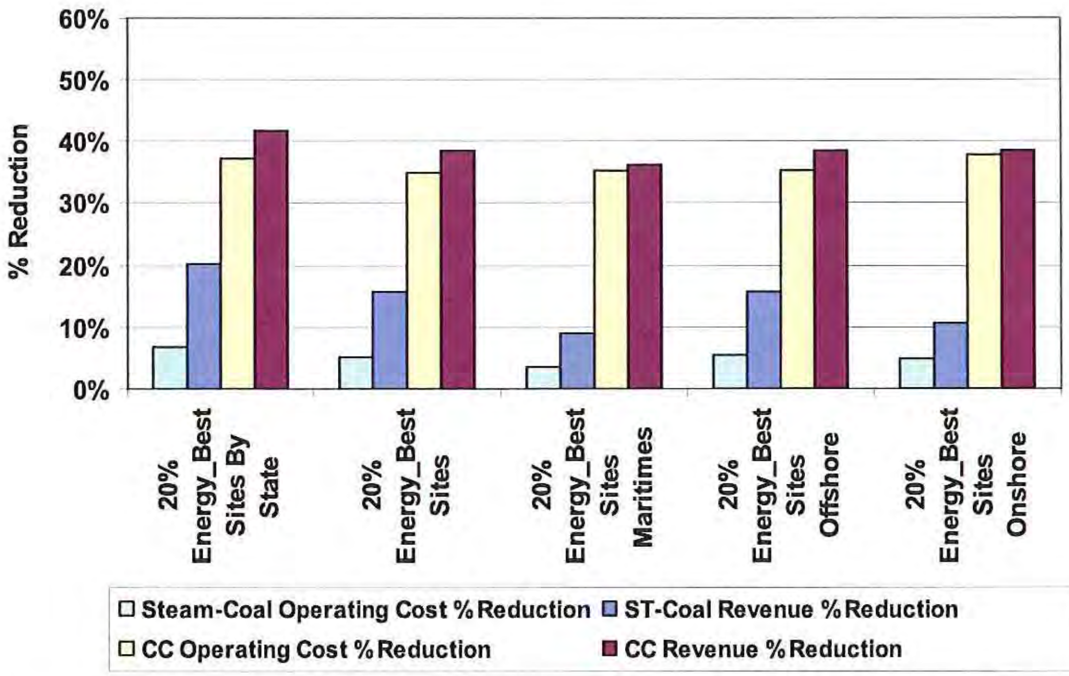


Figure 5–62 ISO-NE CC and St-Coal revenue and operating cost percent reduction per MWh of wind generation, S-o-A forecast, 20% penetration

Figure 5–63 shows the ISO-NE operational cost savings, that is, the reduction in fuel, variable O&M and startup costs from the No Wind Scenario for the various scenarios.

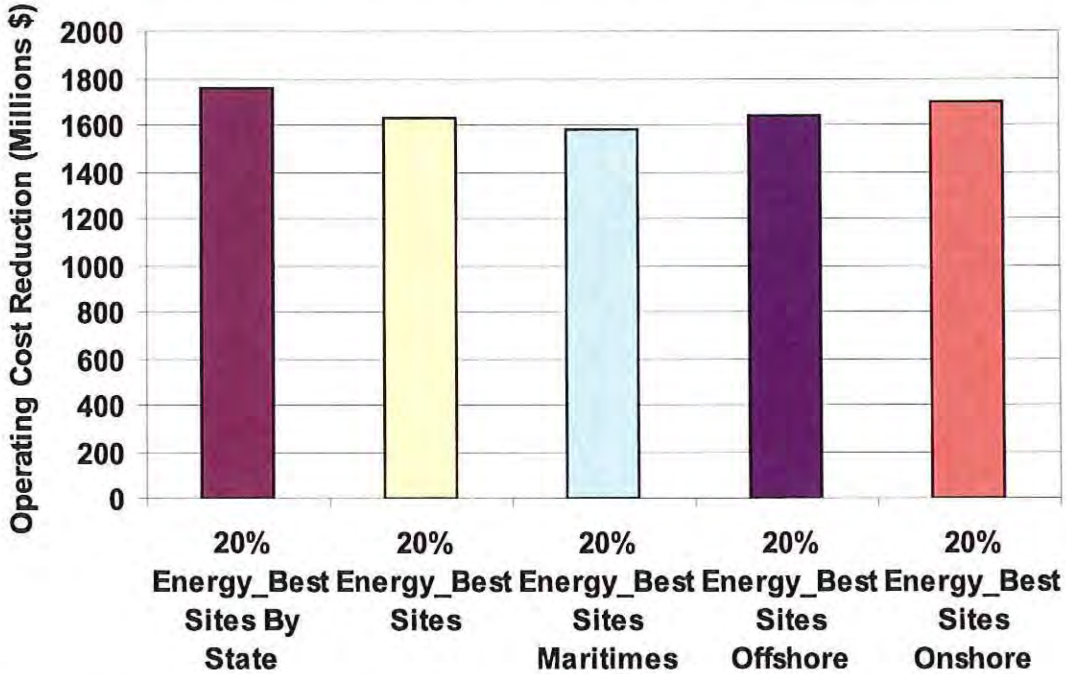


Figure 5–63 ISO-NE annual operating Cost reduction, S-o-A forecast, 20% penetration

If we divide the reduction in Figure 5–63 by the amount of net wind energy in each scenario, then we get the results shown in Figure 5–64. This shows the average value of the wind energy in each case. The value of the wind varies from $55 to $57/MWh.

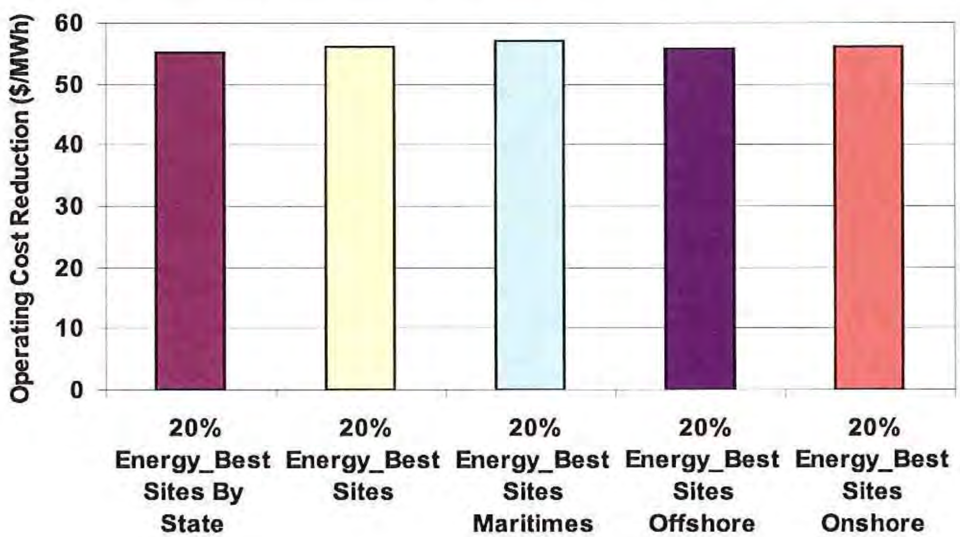


Figure 5–64 ISO-NE annual operating cost reduction per MWh of wind generation, S-o-A forecast, 20% penetration

Figure 5–65 shows the total load payments for energy for the various 20% penetration scenarios. The load payments for energy are what the Wholesale load would pay to buy energy to serve its customers. It is calculated by summing the product of the hourly load weighted LMP by the hourly demand for the year. Taking a closer look at the 20% Energy_Best Sites Onshore scenario, the load payment for energy reduction was about $750M as compared to the No Wind Scenario. 20% Energy_Best Sites By State had the largest reduction; $1.6B.

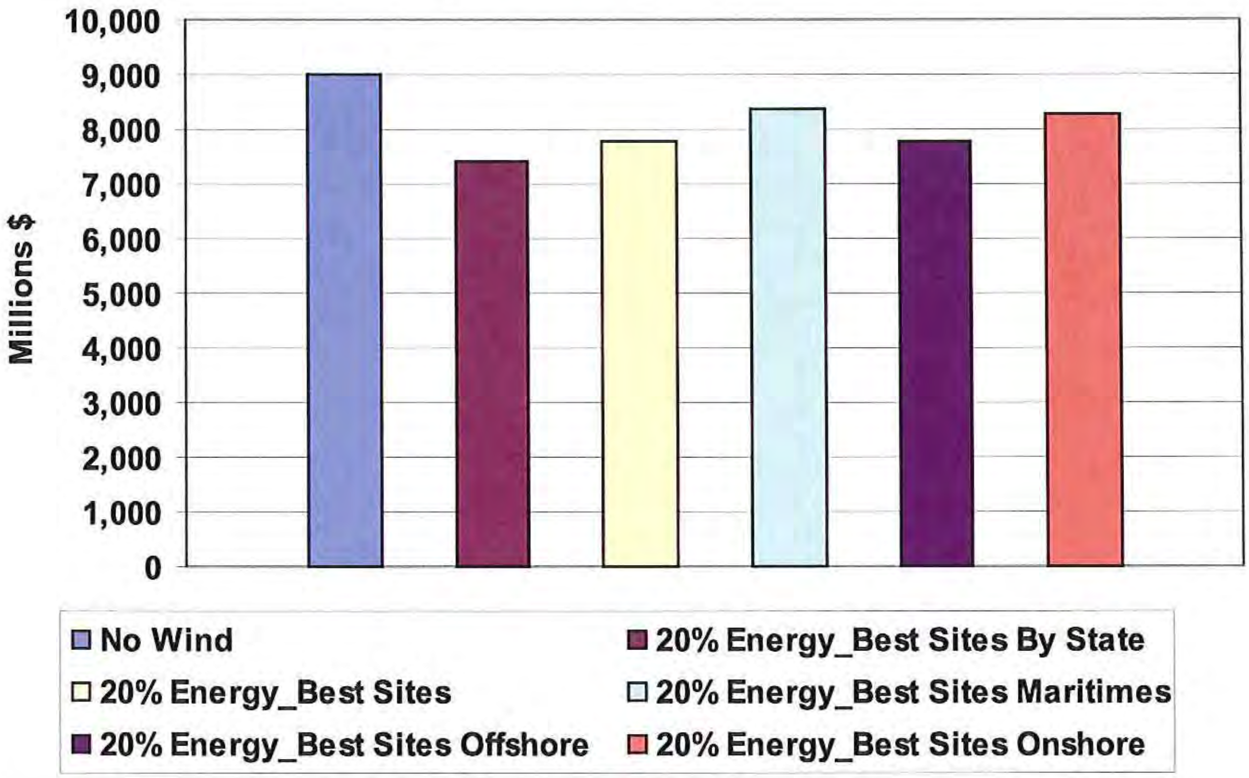


Figure 5–65 ISO-NE wholesale load payments for energy, S-o-A forecast, 20% penetration

Figure 5–66 takes the load payment for energy reduction from Figure 5–65 and divides by the total wind capacity added to ISO-NE in the 20% penetration cases. This is the benefit in load savings per kW of installed wind. The 20% Energy_Best Sites Maritimes and the 20% Energy_Best Sites Onshore have the smallest benefit per kW of installed wind. This is because they have the smallest amount of offshore wind. The offshore wind helps to reduce the LMP at times of peak more and therefore reduces the load payments for energy more.

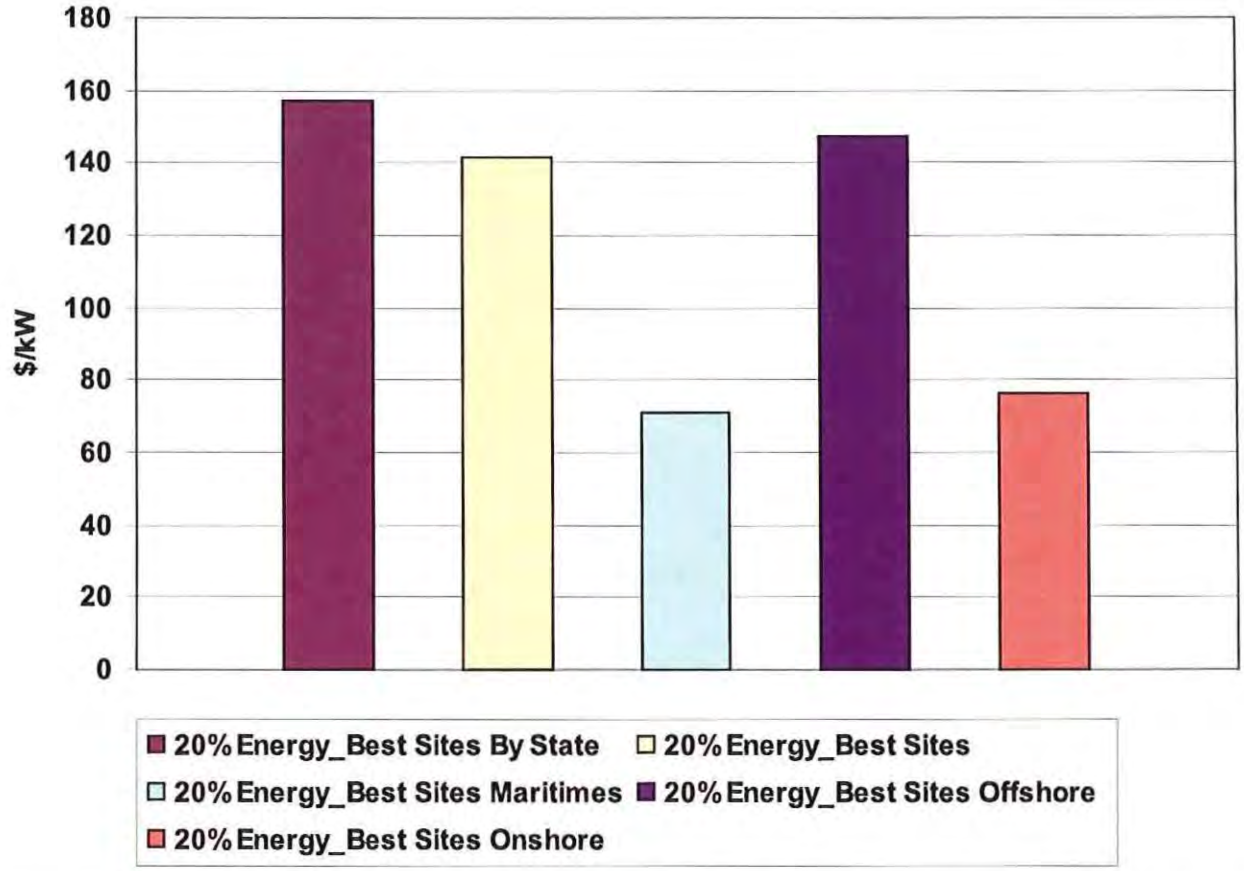


Figure 5–66 ISO-NE wholesale load payment for energy reduction per kW of wind, S-o-A forecast, 20% penetration

Figure 5–67 shows how the reduction in load payments for energy would change if a power purchase agreement (PPA) were put in place for all the wind in ISO-NE. It assumes that all the wind would be paid the same PPA rate per kWh of energy produced. The y-axis is the reduction in load payments for energy and the x-axis represents the PPA rate paid to the wind. The 20% Energy_Best Sites Onshore and 20% Energy_Best Sites By State were examined. The pink point for each curve represents the point at which the wind would be paid the average annual market price for that scenario. Taking the total revenue the wind received and dividing it by the total energy determined this point for each scenario. The market price for each scenario is between 4 to 5 cents/kWh. The point at which there would be no load payment for energy change with the addition of 20% wind penetration is at about 7 cents/kWh for the 20% Energy_Best Sites Onshore and 10 cents/kWh for the 20% Energy_Best Sites By State scenario.

One thing to note is that the load payment for energy reduction does not consider a few items. First, the wind plant revenue may be below the annual total cost of the wind plants causing the wind plant to need a higher than market value PPA. Similarly, conventional generation may need a capacity market price increase to continue to operate with the displacement from increased wind penetration. Finally, there will be cost incurred to build new transmission to get the wind to the market

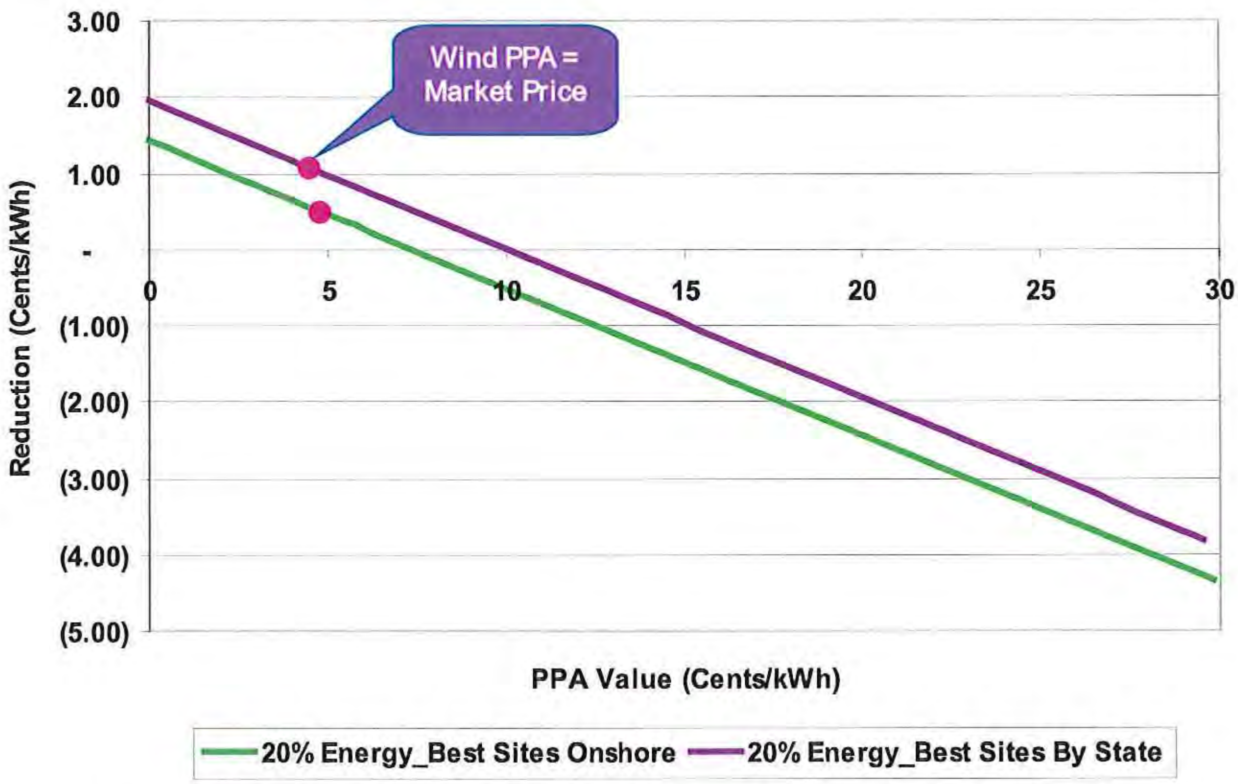


Figure 5–67 Reduction in Wholesale customer Load payments for energy PPA analysis

Although the wind scenario layouts appear very similar at the 50,000-foot level, some diversity exists between the various scenarios. For example, in comparing the operating cost reduction for the 20% Energy Best Sites by State and 20% Energy Best Sites Offshore, using a perfect and S-o-A wind forecast, the perfect forecast results in an operating cost reduction of $1,700M for the 20% Energy Best Sites by State and 1,697M for the 20% Energy Best Offshore as compared to the No Wind scenario. This is a difference of $3M between the scenarios. The S-o-A forecast resulted in a $1,760M reduction for the 20% Energy Best Sites by State and $1,643M reduction for the 20% Energy Best Offshore scenario. This is a difference of $117M between the scenarios. By dispersing the wind throughout the ISO-NE system the forecast error had much less of an impact in the Best Sites by State scenario, than the Best Sites Offshore scenario.

5.2.2.1 Transmission Constraints

The 4 GW transmission overlay was used for the 20% scenarios. This overlay was designed appropriately in order to handle the 8 to 10 GWs of installed wind in the various 20% scenarios. There was very little transmission congestion if any seen in the scenarios. Each scenario was run with full transmission and "copper sheet." The "copper sheet" removed all the transmission constraints within the ISO-NE system. In the 20% Energy_Best Sites Maritimes case the constraints between ISO-NE and the Maritimes were also removed. Figure 5–68 compares the operating cost reduction caused by the wind operation for the constrained and "copper sheet" case. There is only a small difference with and without transmission. For example, there is roughly a $5M difference in the 20% Energy_Best Sites Onshore scenario.

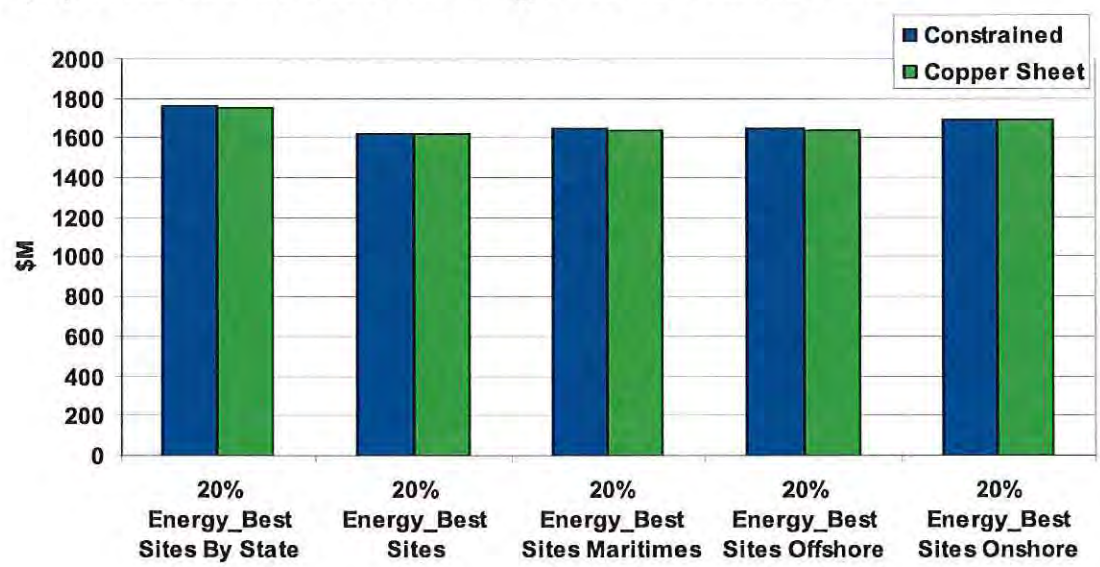


Figure 5–68 Impact of transmission constraints on ISO-NE annual Operating cost reduction, S-o-A forecast, 20% penetration

Figure 5–69 is similar to Figure 5–68 but converts the operating cost reduction to the $/MWh of wind.

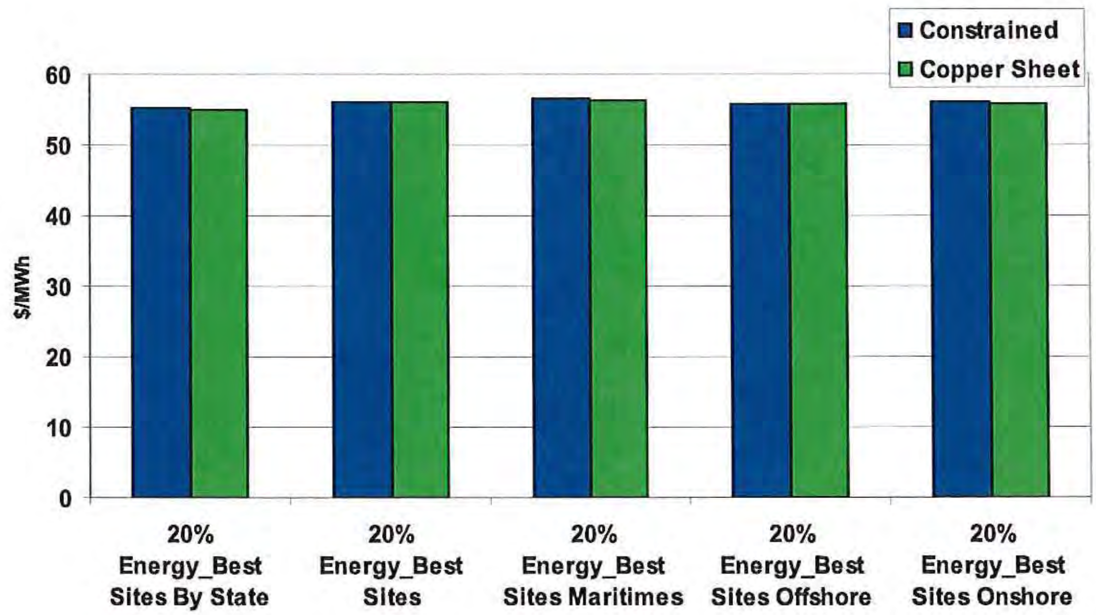


Figure 5–69 Impact of transmission constraints on ISO-NE operating cost reduction per MWh of Wind generation, S-o-A forecast, 20% penetration

Figure 5–70 is a comparison of the ISO-NE load weighted LMP with and without transmission constraints. As with the operating cost reduction, there is very little difference.

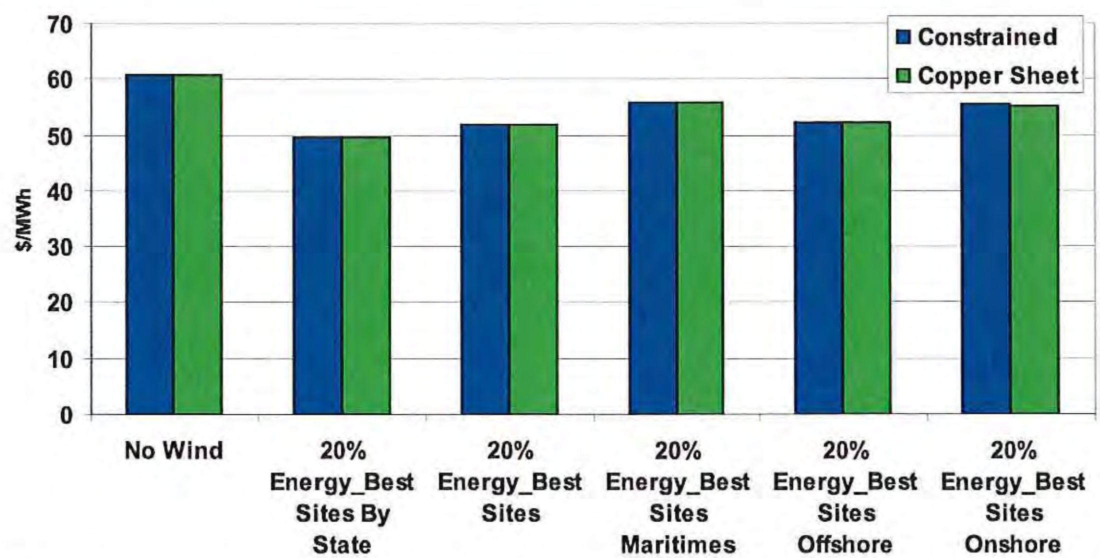


Figure 5–70 Impact of transmission constraints on ISO-NE Load Weighted Average LMP, S-o-A forecast, 20% penetration

Table 5–11 summarizes the maximum and minimum flow on each interface constraint in ISO-NE in the copper sheet case. The red highlighted cells show where the maximum flow would have been above the limit, for at least one hour, for the constrained case for the various scenarios. The column with the heading "4 GW" is the maximum and minimum limit for the interface in the constrained case.

Table 5–11 ISO-NE Copper Sheet Transmission Interface Summary, S-o-A forecast, 20% penetration

			20% Wind Penetration									
	4GW		State		Offshore		Onshore		Sites		Maritimes	
Interface	Min Rating (MW)	Max Rating (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)	Min Flow (MW)	Max Flow (MW)
North-South	-6800	6800	-331	5435	-821	5193	320	8356	240	5368	-132	6045
Boston Import	-4900	4900	658	5168	656	5019	678	5260	680	5229	665	5059
New England East-West	-7900	7900	-2674	4204	-1743	5883	-1795	5254	-1609	5439	-1744	4574
Connecticut Export	-4500	4500	-3775	1638	-3737	1259	-3923	1259	-3820	1259	-3619	896
Connecticut Import	-6600	6600	-1642	3770	-663	3754	-663	3918	-663	3815	-458	3614
Southwestern Connecticut Import	-3650	3650	234	2716	68	2554	68	2612	68	2472	162	2477
Norwalk-Stamford Import	-1650	1650	31	1478	109	1476	479	1466	110	1466	477	1412
New York-New England	-1600	1600	-1525	1600	-1600	1600	-1600	1600	-1600	1600	-1600	1600
Orrington South	-5500	5500	-444	3178	-467	3145	-206	4669	-422	3212	34	3917
Surowiec South	-5200	5200	-595	3071	-625	3272	-305	5957	-570	3984	-201	4144
Maine-New Hampshire	-5700	5700	-913	3031	-1005	3374	-438	5945	-645	3917	-322	4224
SEMA Export	-9999	9999	-1068	2154	-1025	4696	-1215	1319	-1008	2644	-1213	1400
West - East	-5100	5100	-3470	2669	-5297	1739	-4954	1791	-4853	1758	-4454	1740
NB - NE	-500	1000	-500	1000	-500	1000	-500	1000	-500	1000	-500	1000
SEMA/RI Export	-6500	6500	-1153	3779	-974	5940	-1908	2634	-1080	4359	-1846	2632

Figure 5–71 through Figure 5–76 show flow duration curves for the interfaces that were highlighted in red in Table 5–11. Orrington South was also included since historically it has been a bottleneck in ISO-NE. The flows are from the constrained case. The solid horizontal lines are the limits for the various transmission overlays used in the study. This gives a rough idea of what the impacts would be if a smaller overlay were used. For example, if the 2 GW overlay was used in the 20% Energy_Best Sites Onshore case the Orrington South would be constrained roughly 1,700 hours. Note that the 20% Energy_Best Sites Maritimes includes a 1,500 MW HVDC cable from the Maritimes to Massachusetts.

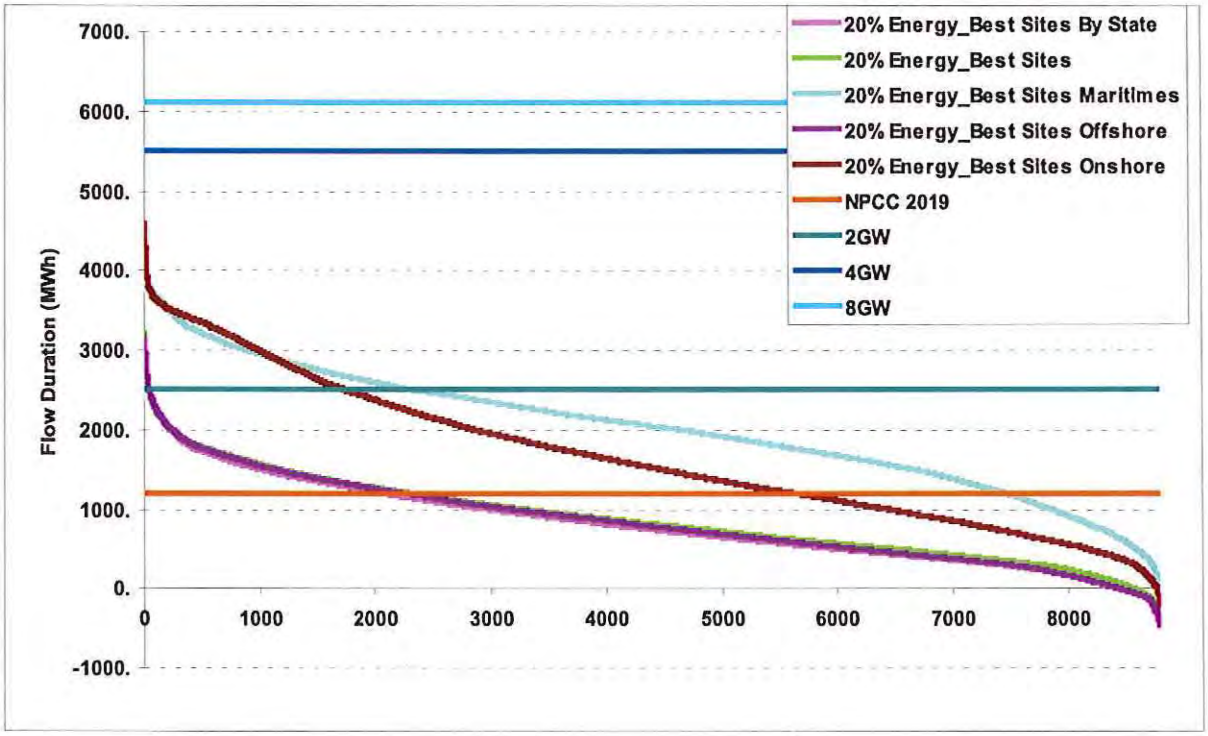


Figure 5–71 Orrington South interface flow, S-o-A forecast, 20% penetration

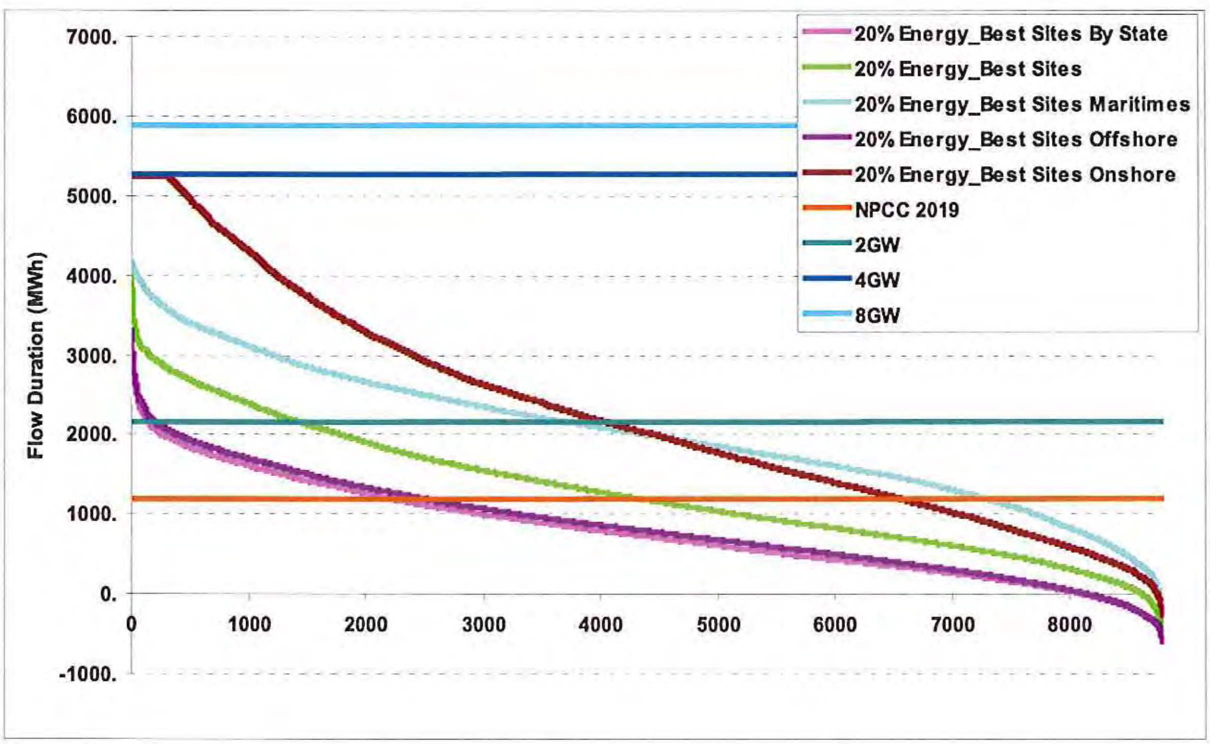


Figure 5–72 Surowiec South interface flow, S-o-A forecast, 20% penetration

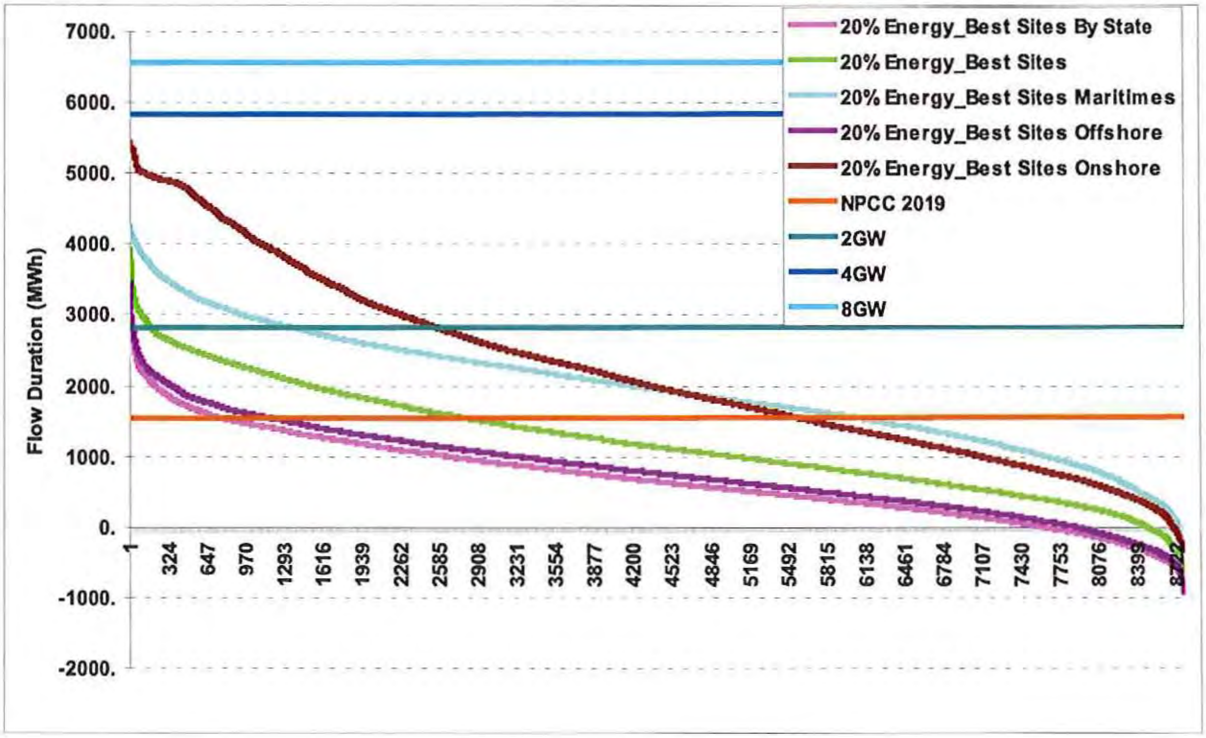


Figure 5–73 Maine/New Hampshire interface flow, S-o-A forecast, 20% penetration

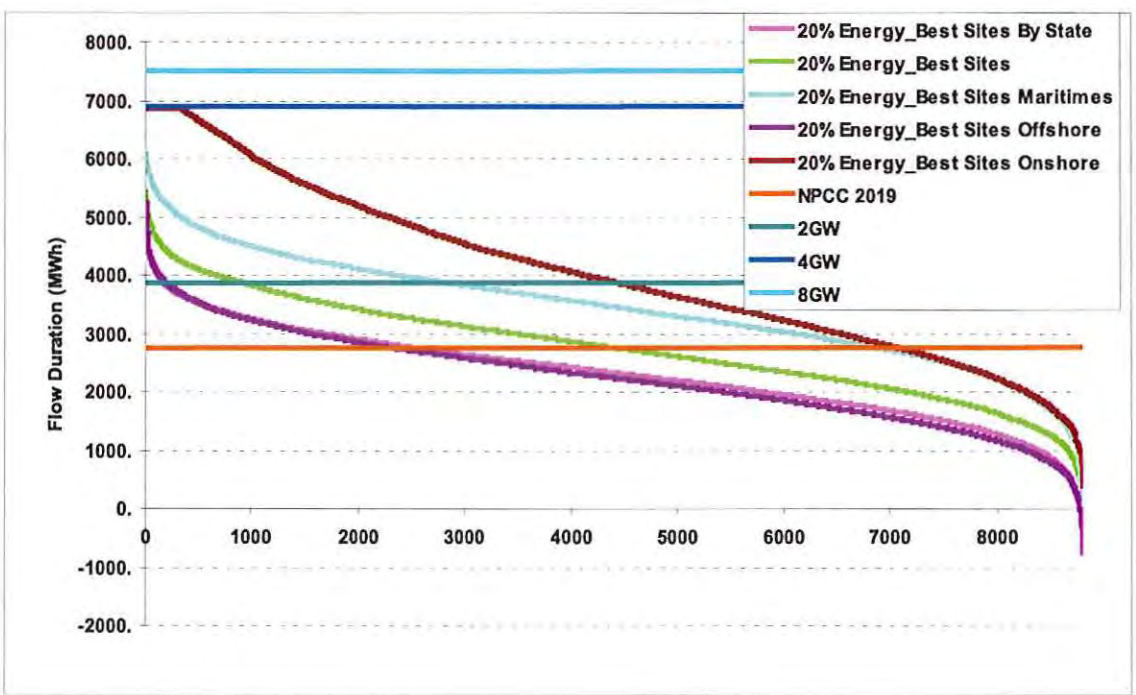


Figure 5–74 North /South interface flow, S-o-A forecast, 20% penetration

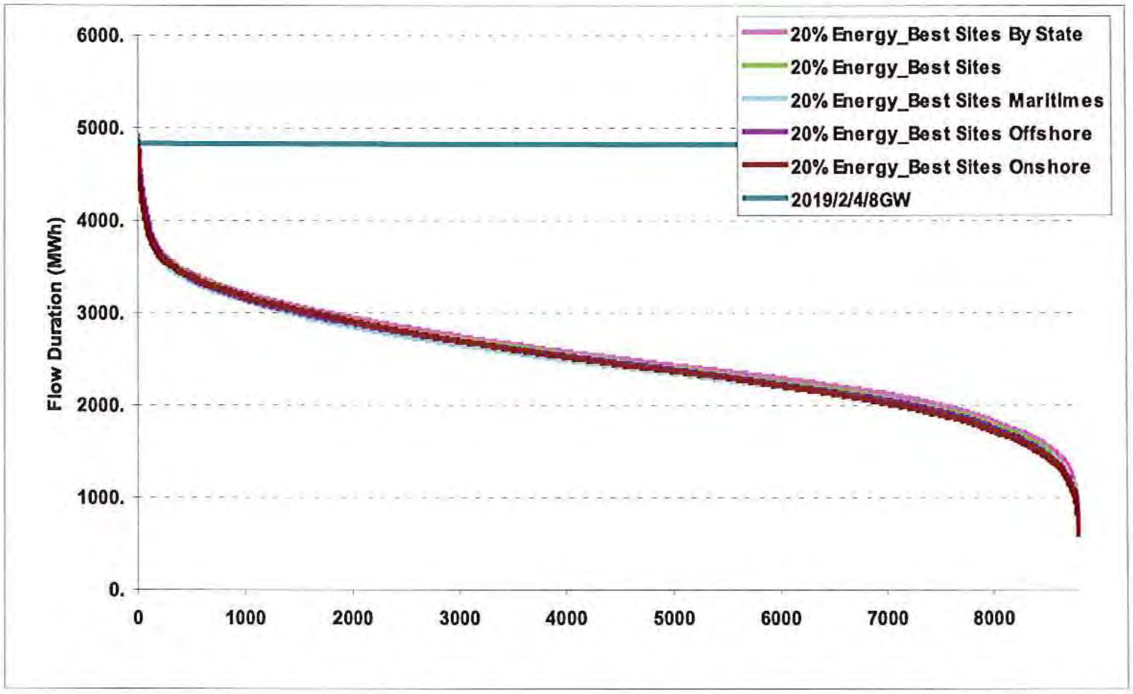


Figure 5–75 Boston Import, S-o-A forecast interface flow, 20% penetration

Figure 5–76 shows the flows across the sum of the ISO-NE to Maritimes interfaces. The blue line represents the total flow in the 20% Energy_Best Sites Maritimes scenario. It shows that the imports into ISO-NE increase substantially with the addition of wind in the Maritimes.

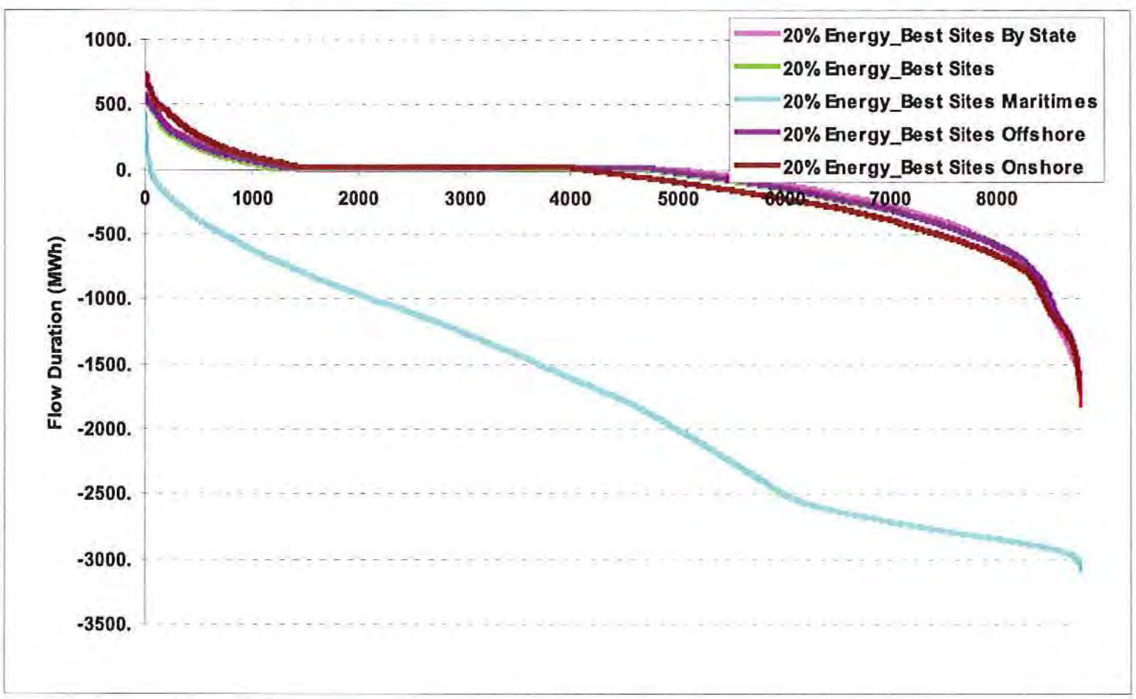


Figure 5–76 ISO-NE to NB (Maritimes case contains HVDC cable from Maritimes to Massachusetts) interface flow, S-o-A forecast, 20% penetration

5.2.2.2 ***Ramp and Range Capability***

Figure 5–77 and Figure 5–78 show duration curves of the hourly range up and down capacity available for the various scenarios. The graphs are based on the units that are committed and online. The maximum range up available was roughly 9,900 MW and the minimum was 763 MW. The range down maximum is roughly 14,850 MW and the minimum is 0 MW. This occurs from two to 30 hours for the various scenarios. This is less than 0.3% of the year. In this situation, the wind could potentially be curtailed to free up range down capacity.

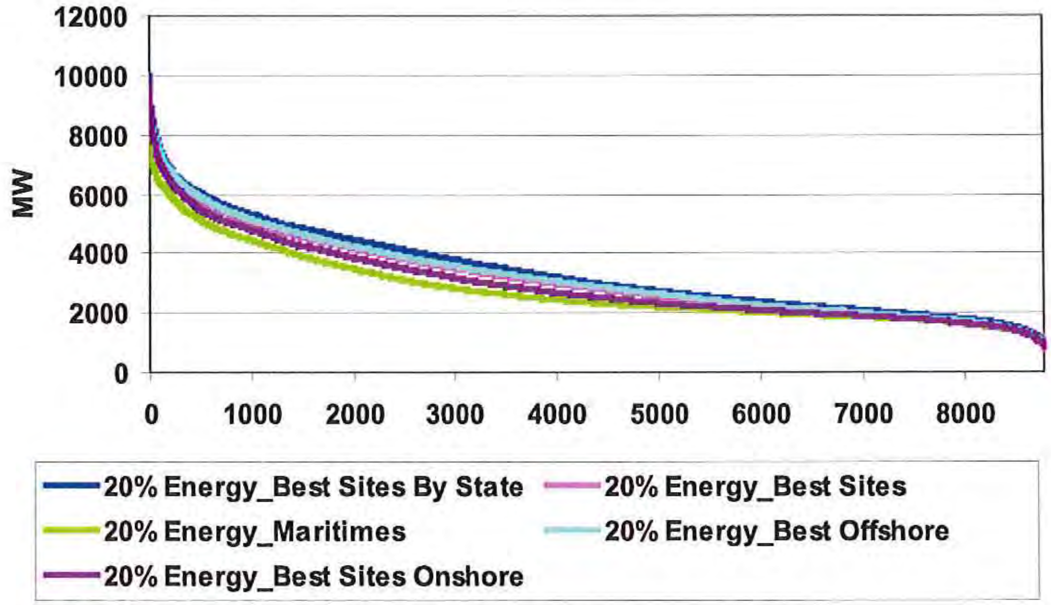


Figure 5–77 Hourly Range Up Capability, S-o-A forecast, 20% penetration

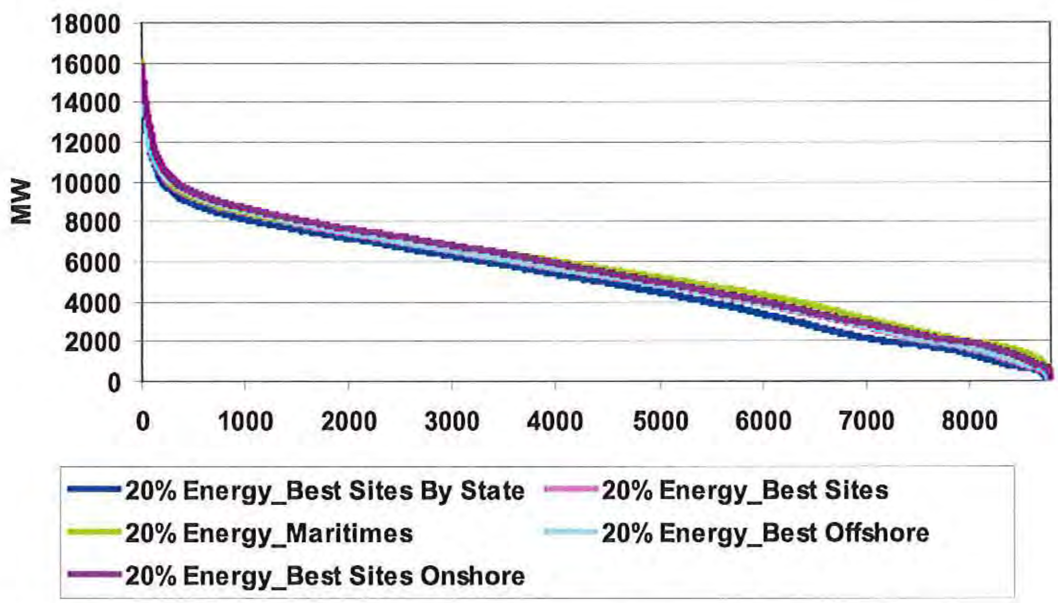


Figure 5–78 Hourly Range Down Capability, S-o-A forecast, 20% penetration

Figure 5–79 and Figure 5–80 compare the range up and down capability for the No Wind and 20% Energy_Best Sites Onshore case. As expected, the range up increases and the range down decreases with wind generation added to the system.

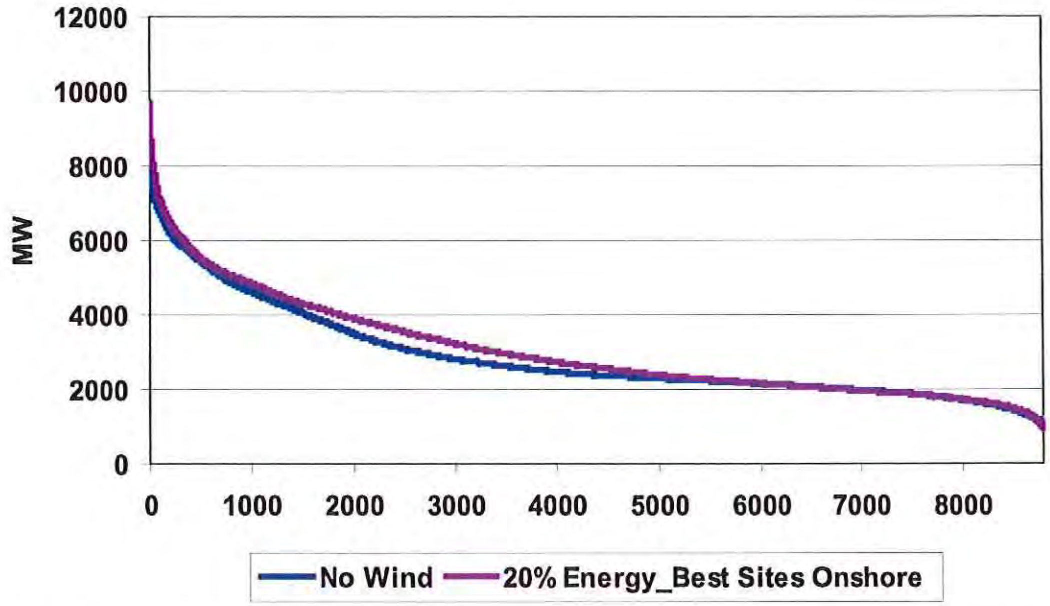


Figure 5–79 Hourly Range Up Capability, S-o-A forecast, No Wind vs. 20% Energy_Best Sites Onshore

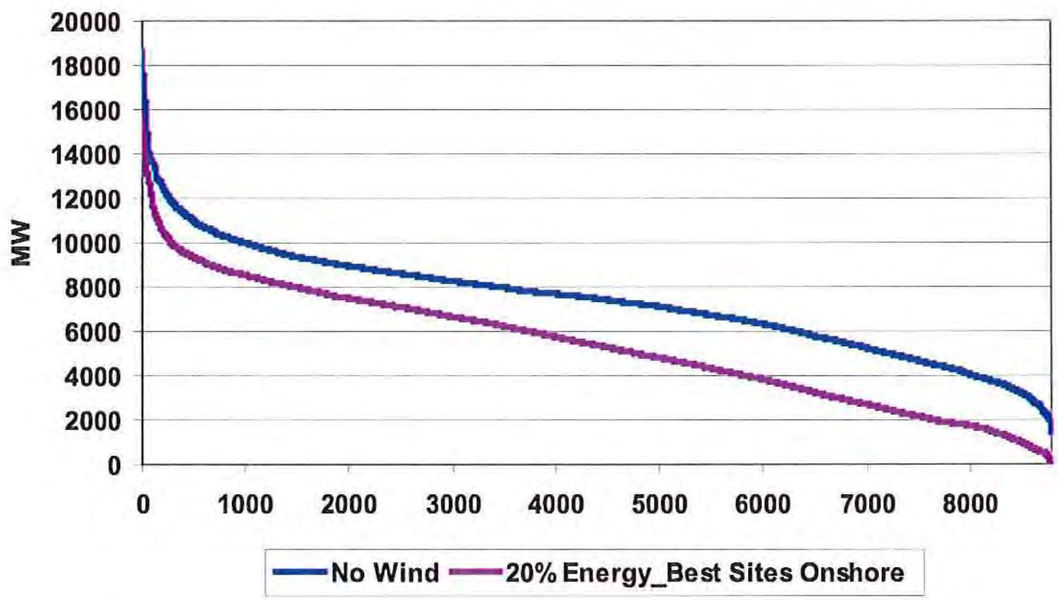


Figure 5–80 Hourly Range Down Capability, S-o-A forecast, No Wind vs. 20% Energy_Best Sites Onshore

Figure 5–81 and Figure 5–82 show duration curves of the hourly ramp up and down capacity available for the various scenarios.

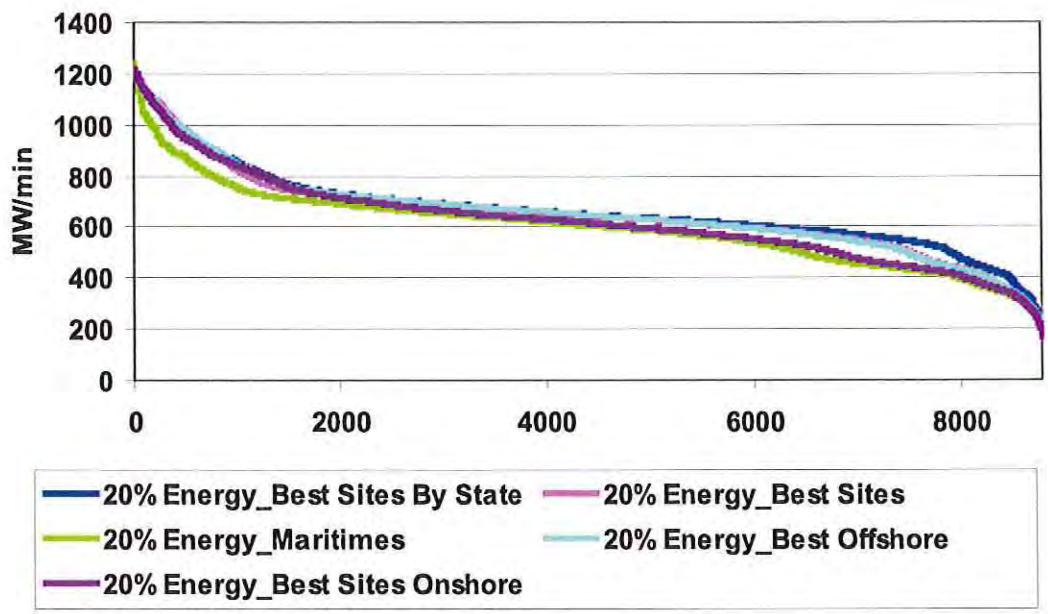


Figure 5–81 Hourly ramp-up capability, S-o-A forecast, 20% penetration

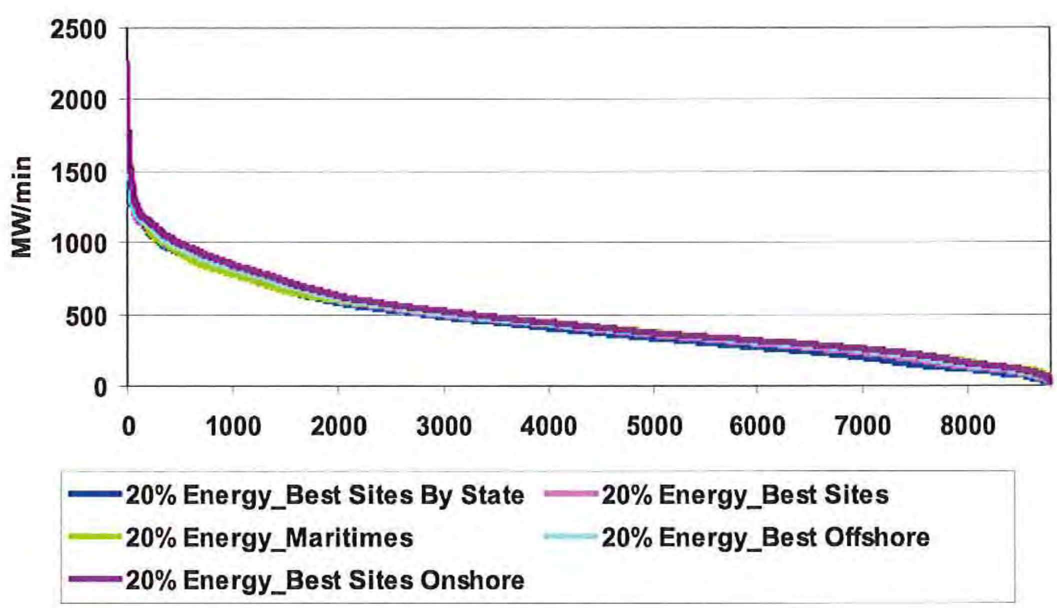
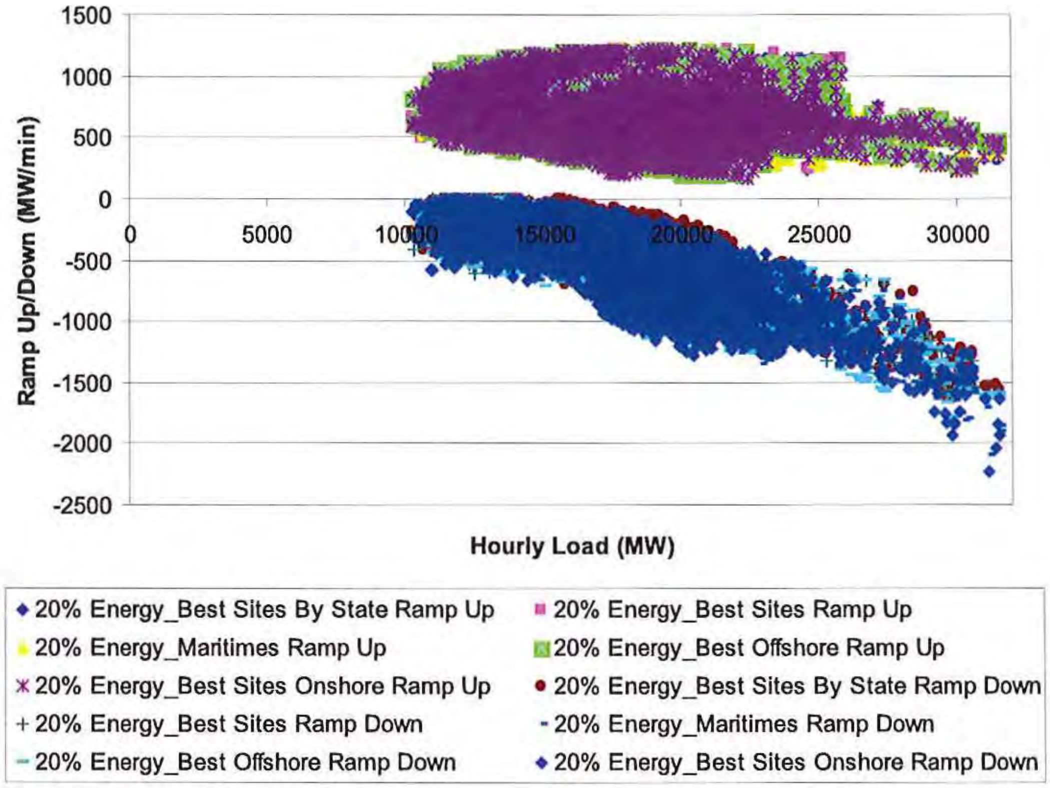


Figure 5–82 Hourly ramp-down MW/min capability, S-o-A forecast, 20% penetration

As can be seen in the figures, the maximum available ramp up is roughly 1,200 MW/min and the minimum is 165 MW/min. This can be compared to the regulation requirements, which increase from roughly 80 MW to 310 MW at 20% penetration, as seen in section 4.6.1. Over a 5-minute period, 310 MW would translate to 62 MW/min, which is less than half of what is available, indicating that the increased regulation requirement could easily be met. The ramp down maximum is roughly 2,200 MW/min and the minimum is 0 MW/min. As expected, the hours at 0 for the ramp down is the same as the range down.

Figure 5–83 compares the hourly ramp up/down capability against the ISO-NE hourly load for all of the 20% scenarios. The upper figure shows the total range and the bottom figure expands the graph to just show the hours with less than +/- 100 MW/min ramping capability. The ten-minute spinning reserve for ISO-NE is 700 MW, which would correspond to a ramp up capability of 70 MW/min. As can be seen from the curve, the ramp up capability never falls below 165 MW/min. Again, from the ramp up side this does not appear to present any difficulty. However, the ramp down capability may be deficient several hundred hours and possibly require either changes to the unit commitment or spilling of some wind energy.



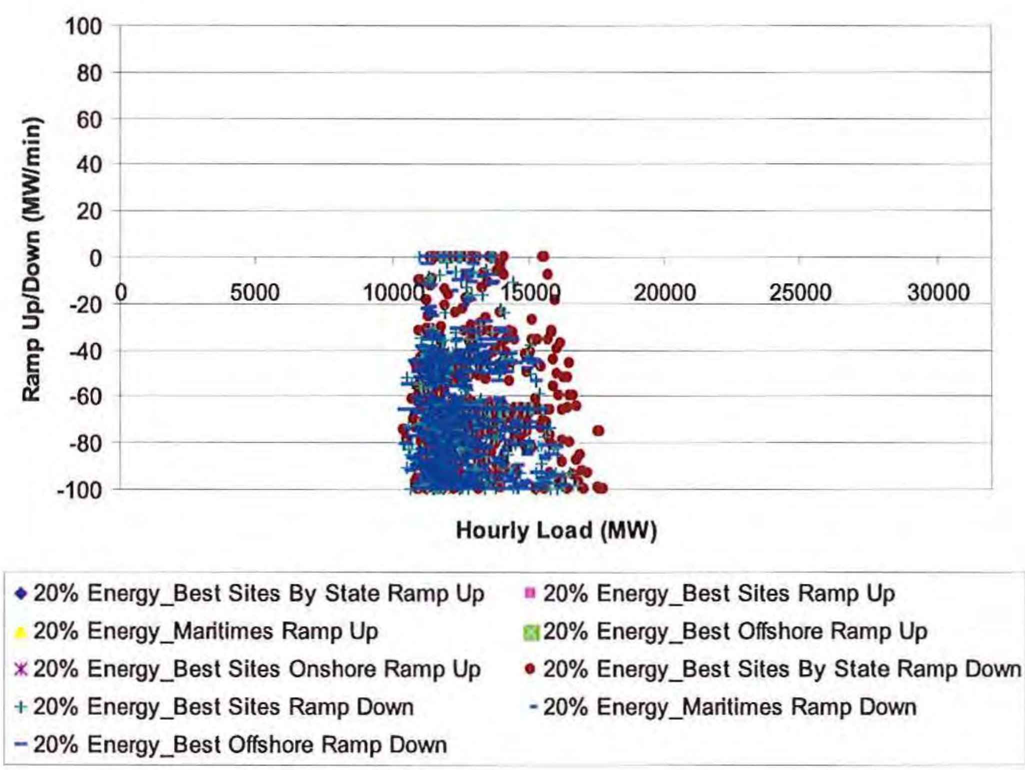


Figure 5–83 Hourly Ramp Up/Down vs. Load, S-o-A forecast, 20% Energy

Table 5–12 shows a summary of the number of hours with less than 100 MW/min of ramp down capability for the various 20% scenarios.

Table 5–12 Number of hours with ramp down capability < 100 MW/minute, 20% scenarios.

Scenario	# Hours
20% Energy_Best Sites By State	612
20% Energy_Best Sites	479
20% Energy_Best Sites Maritimes	225
20% Energy_Best Sites Offshore	451
20% Energy_Best Sites Onshore	374

Figure 5–84 through Figure 5–87 look at the range and ramp for a week in a spring month and summer month for the 20% energy scenarios. The shape is generally the same for the various 20% penetration scenarios. The week of April 13 has some hours where the down range and ramp go to 0 MW. The differences between scenarios are caused by differences in wind generation and a given online resource's dispatch compared to its up or down limits.

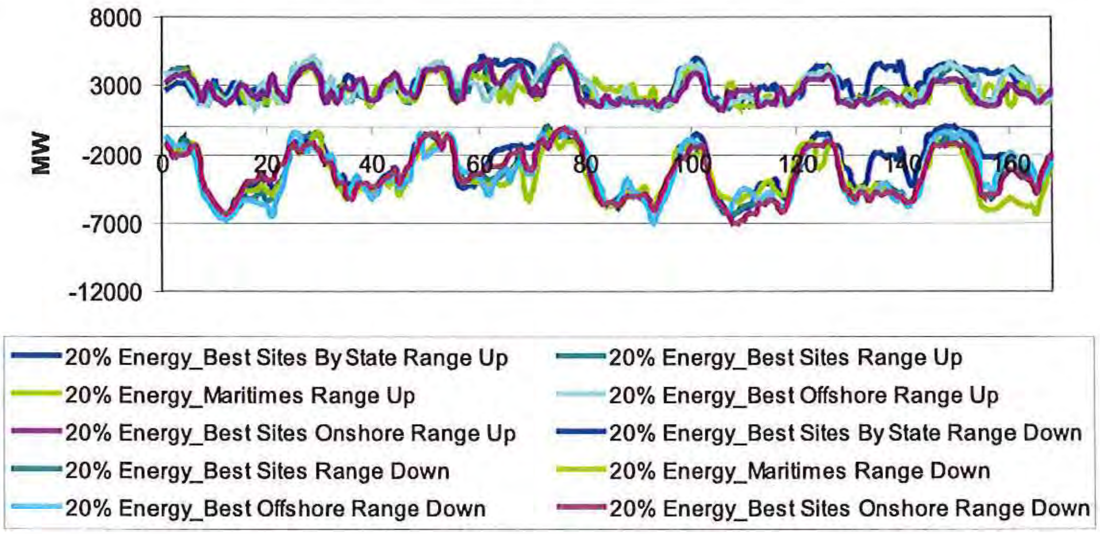


Figure 5–84 Range up/down capability week of April 13, S-o-A forecast, 20% penetration

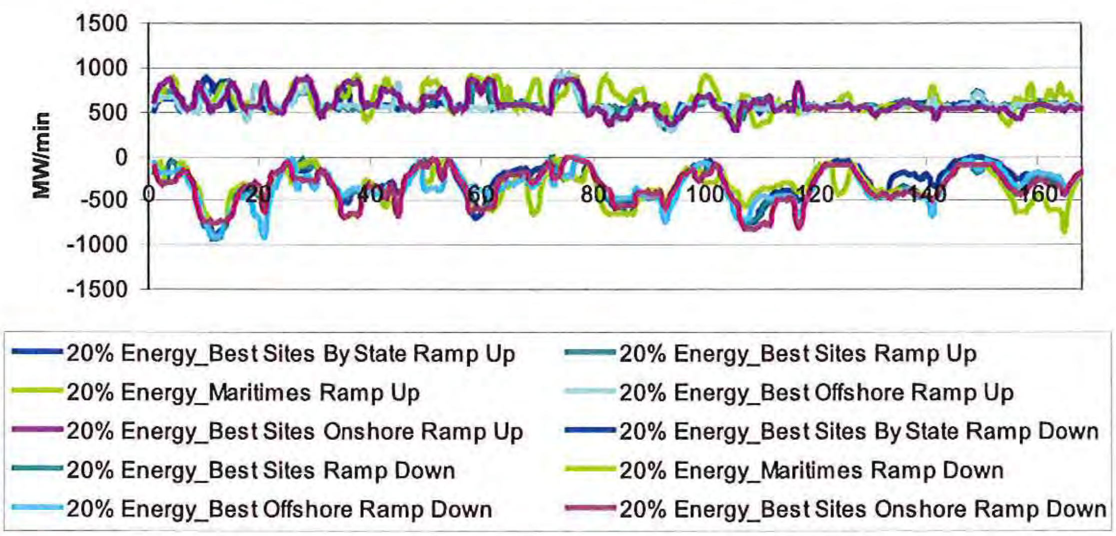


Figure 5–85 Ramp up/down MW/min capability week of April 13, S-o-A forecast, 20% penetration

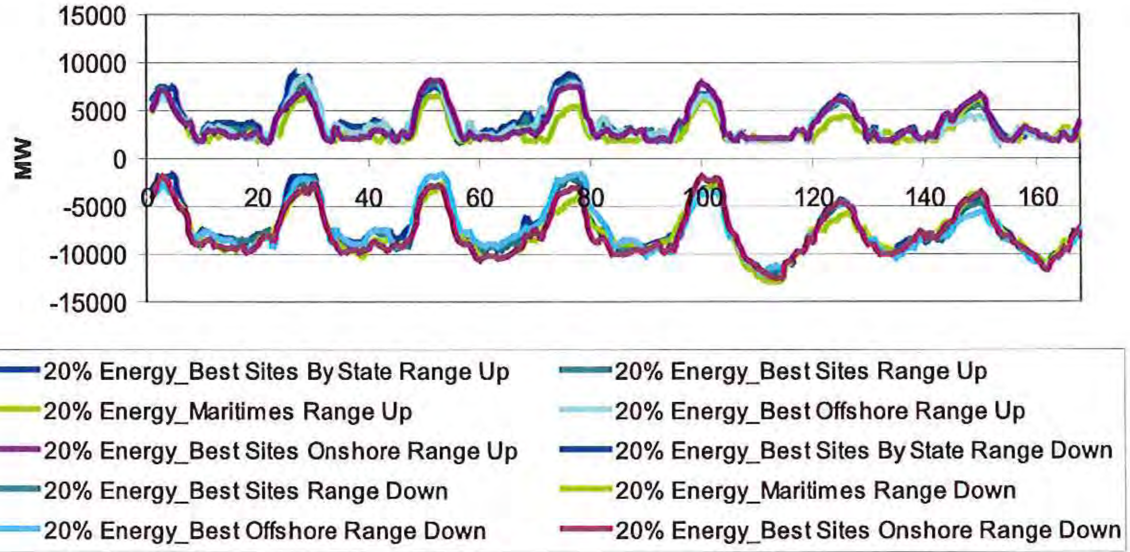


Figure 5–86 Range up/down capability week of July 6, S-o-A forecast, 20% penetration

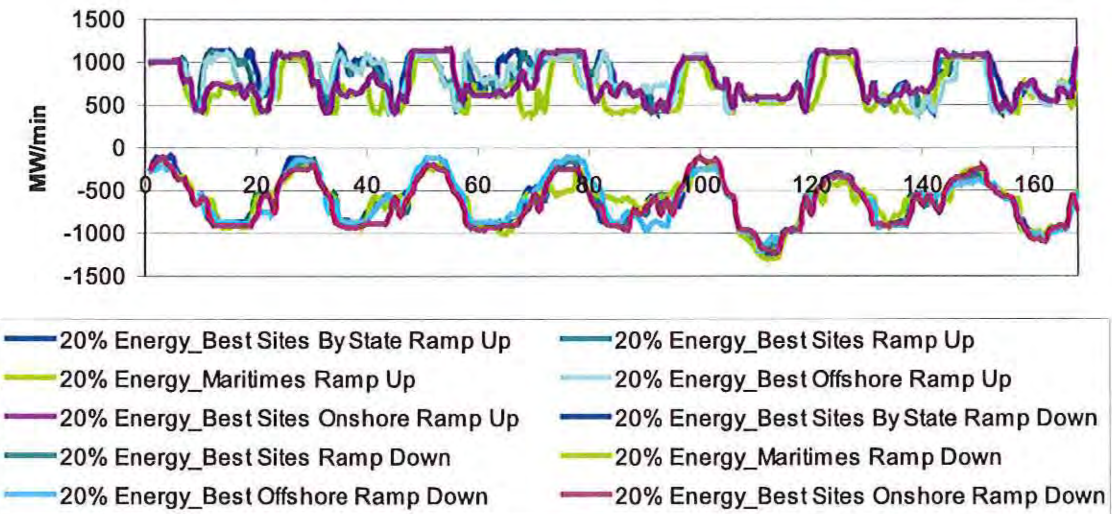


Figure 5–87 Ramp up/down MW/min capability week of July 6, S-o-A forecast, 20% penetration

5.2.3 14% Wind Penetration Key Findings

A similar analysis was performed looking at all of the 14% penetration scenarios. The charts for these, similar to the ones for the additional 20% scenarios, are shown in Appendix C. In general the relative results between the cases were the same as was shown for the 20% cases; however the fuel displacement and emission reductions were smaller due to the reduced wind penetration. The major difference was in the transmission congestion. The 14% penetration cases used the 2 GW overlay while the 20% scenarios used the 4 GW overlay. As was shown, the use of the 4 GW overlay for the 20% penetration cases essentially eliminated the congestion within the system. Although congestion was more of a factor in the 14% it did not seem to significantly affect the operating costs. This is likely due to the fact that gas is on the margin on both sides of the constraints, so that while the constraint is limiting there is not that much of a cost difference behind it. Because the costs were relatively unaffected by the congestion that did occur, the operation of the system was similar to the operation of the system with 20% wind energy.

5.2.4 ***Value of Forecasts***

Figure 5–88 examines the value of the wind forecast as wind penetrations increase. The figure shows the difference in system operating costs between using no forecast and a case with a perfect day-ahead forecast and the corresponding case using a State-of-the-Art forecast.

In the production cost simulation, if no wind forecast is provided, the commitment phase of the model does not include this energy. It shows up in the dispatch phase only. This causes over commitment of thermal units and can lead to excessive spinning reserve and curtailment of the wind. If a perfect forecast is used, the model has perfect knowledge of the wind produced in both phases of the model. When a S-o-A forecast is used, the commitment phase uses an imperfect but relatively accurate day-ahead forecast of the wind. This forecast will be low or high of the actual wind used in the dispatch phase of the program. If the forecast is low compared to the actual wind, over commitment of thermal units will occur and potentially not enough thermal units will be committed. This can lead to increased quick start operation and spinning reserve violations.

Not surprisingly, the importance of the forecast increases at higher penetration levels. But even at the lowest level of penetration using the wind forecast can reduce operating costs by $50 million per year. Another important aspect is that implementation of wind forecasting in the day-ahead commitment and real time dispatch early in the actual wind integration process will allow the system operators to gain experience and comfort levels before it reaches the billion dollar level of impact. The study results show that improving the forecasting can have some benefit, but that the critical aspect is in using the best level of forecasting that is currently available. At higher penetrations the S-o-A forecast appears to provide roughly 94% of the value of using a forecast with perfect knowledge.

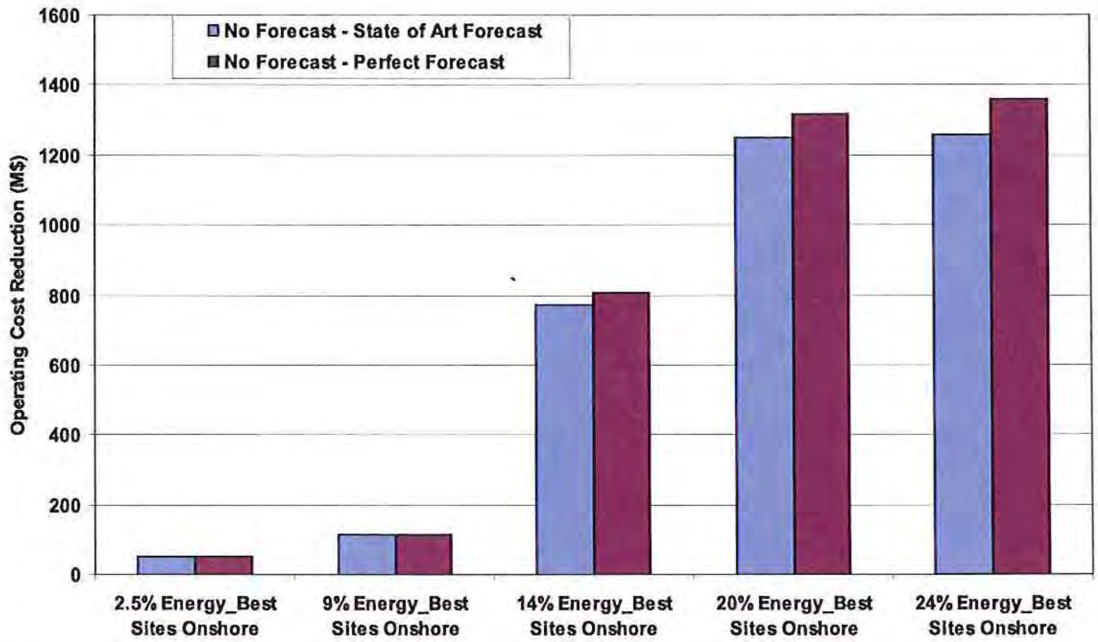


Figure 5–88 System operating cost impacts of forecast (M$), S-o-A forecast, Best Sites Onshore

5.2.5 Annual Profile Sensitivities

Most of the analysis was performed using the load and wind profiles from 2006 to simulate 2020. All of the primary cases were also run using the shapes from 2004 and 2005 using all the same assumptions. As detailed in section 2.1.2, the load extrapolation method used for the study, results in different total load energy for the various shape years. To fully capture the impacts of the different shape years, the loads were ratioed up, so that the annual peak matched the target and the load factor was kept as is.

Table 5–13 summarizes the variations between the different shape years. Although the wind penetration target was 20% energy, the load extrapolation methodology causes lower penetration for each year.

Table 5–13 Annual shape variation summary, 20% Energy_Best Sites Onshore

20% Best Sites Onshore	2004	2005	2006
Peak Load (GW)	31.5	31.5	31.5
Load Energy (GWh)	174,417	160,749	149,241
Load Factor	63%	58%	54%
Wind Capacity (GW)	9.779	9.779	9.779
Wind Energy (GWh)	29,575	28,973	28,832
Wind Capacity Factor	35%	34%	34%
Annual Penetration	17%	18%	19%

Figure 5–89 compares the instantaneous penetrations for each shape year for the 20% Energy_Best sites Onshore. The solid blue line is at the original 20% target mark. The 20% energy was based on the three-year average wind energy (29,060 GWh) and the CELT report forecasted 2020-load energy value (149,241 GWh). As shown, the hourly penetration varies hourly and hit 20% for a very few hours.

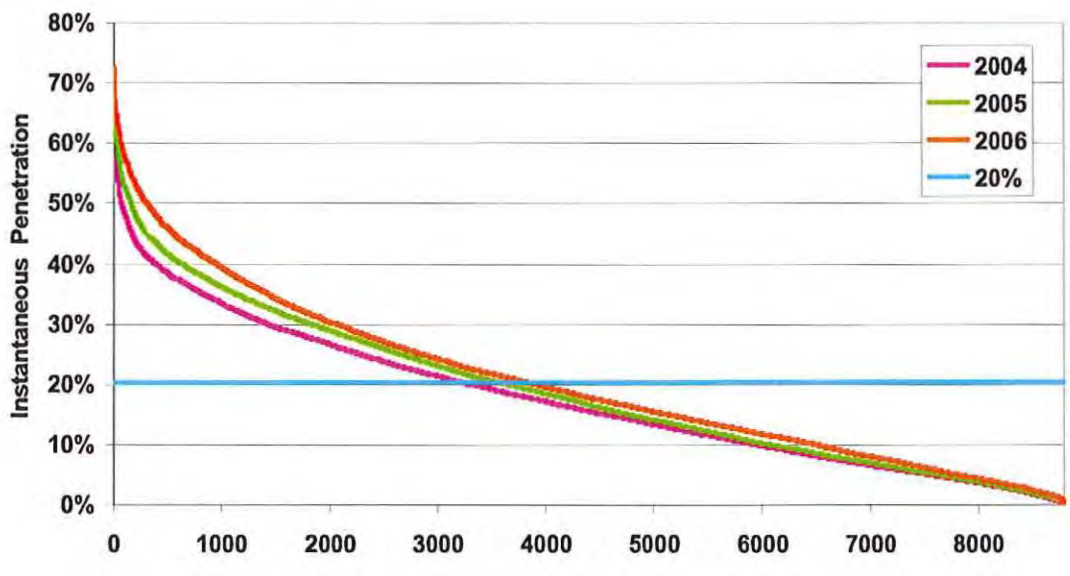


Figure 5–89 Instantaneous wind penetration, S-o-A forecast, 20% Energy_Best Sites Onshore, by shape year

Figure 5–90 compares the generation by type for the No Wind and 20% Energy_Best Sites Onshore scenario for the three shape years. As expected, the higher load energy in 2004 and 2005 causes the need for more overall generation as compared to 2006. This results in more CC operation. As we saw in previous results, the wind displaces mostly CC generation.

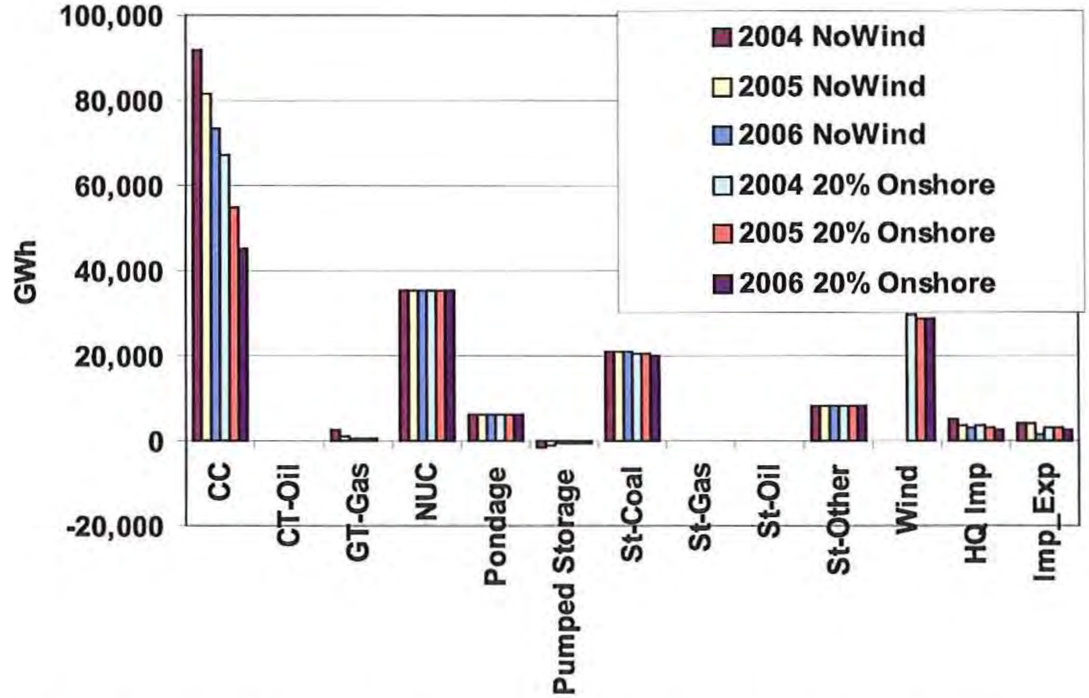


Figure 5–90 ISO-NE generation by type, S-o-A forecast, 20% Energy_Best Sites Onshore, by shape year

Figure 5–91 zooms in on the peaking operation for the 3 shape year cases. The wind penetration drops the operation for the 3 shape years to similar levels. The 2004 extrapolated load has a higher load factor than the other two years. This results in higher peaking operation. With the addition of wind, the wind shifts the dispatch stack up and CC operation replaces the most of the peaking operation.

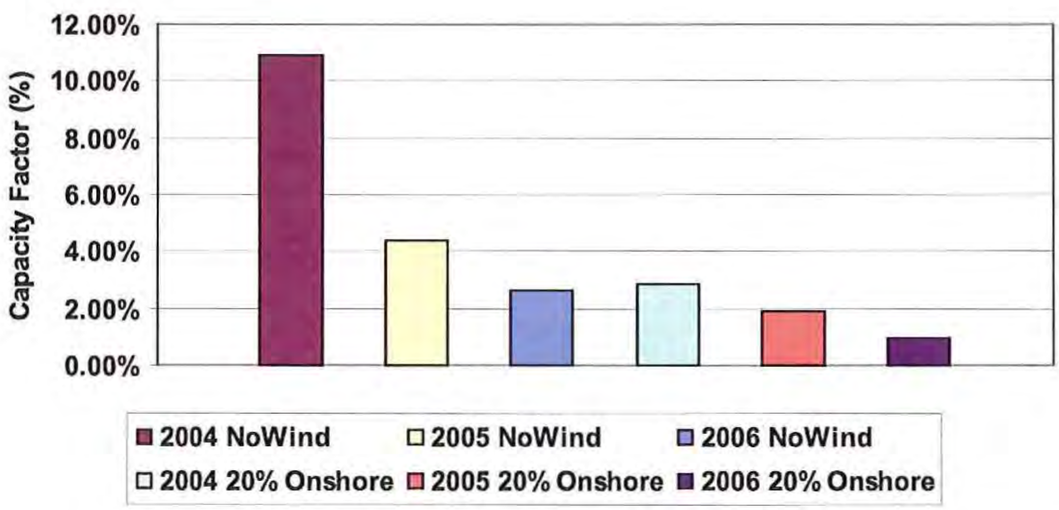


Figure 5–91 ISO-NE peaking plant operation, S-o-A forecast, 20% Energy_Best Sites Onshore, by shape year

Figure 5–92 shows the ISO-NE load weighted annual average LMP. As expected, the 2004 No Wind case has the highest LMP value while the 2006 20% Energy_Best Sites Onshore has the lowest. The wind penetration has the greatest impact on LMP for the 2004 shape year case as it displaces the largest amount of peaking operation in this year. The addition of wind also reduces the LMP in the 2005 and 2006 shape year cases.

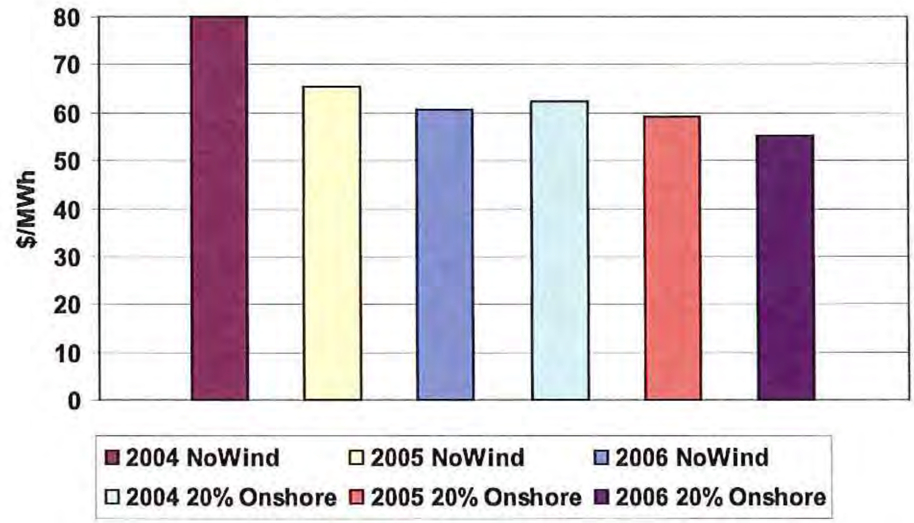


Figure 5–92 Average load weighted ISO-NE LMP, S-o-A forecast, 20% Energy_Best Sites Onshore, by shape year

Figure 5–93 compares the LMP duration curves for the three annual shapes. With no renewable generation on the system, the LMP ranges from a high of approximately $400/MWh to a low of about $38/MWh. All of the 20% penetration scenarios have similar impacts on the spot price for the three shape years. Introducing 20% penetration of wind to the system, reduces highest cost for all three-shape years by roughly $40/MWh and the lowest hours by roughly $30/MWh.

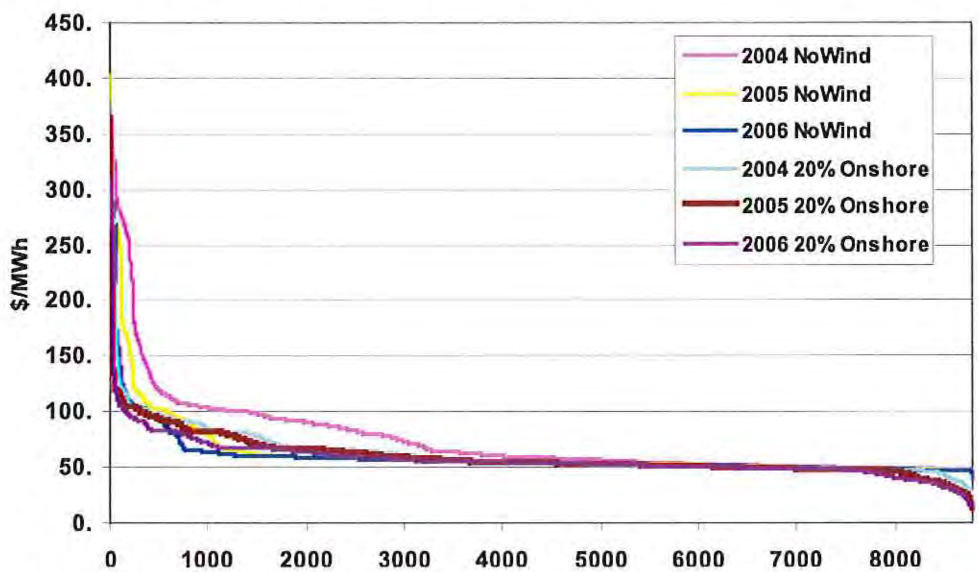


Figure 5–93 Annual LMP duration curve, S-o-A forecast, 20% Energy_Best Sites Onshore, by shape year

Figure 5–94 compares the PSH operation for the three different shape years with and without wind. With the addition of 20% wind penetration, the PSH operation decreases. This may be counterintuitive.

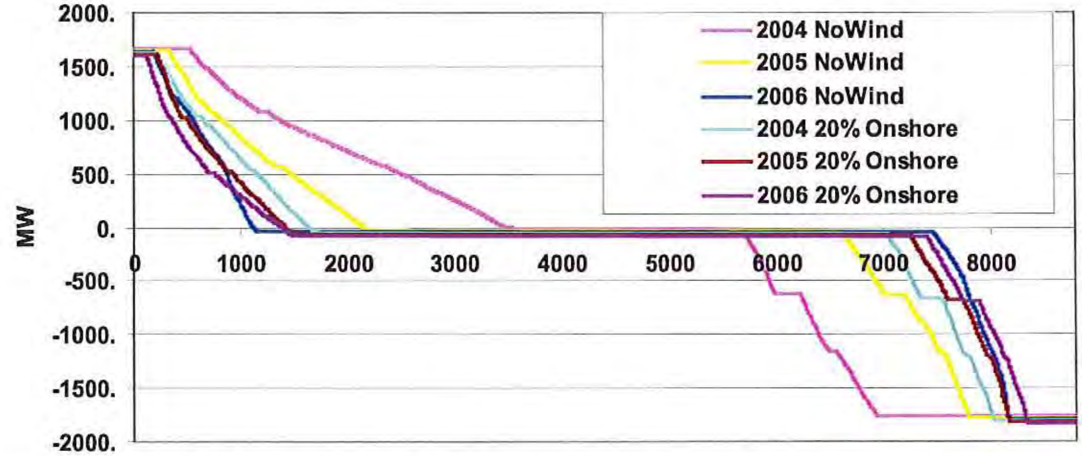


Figure 5–94 ISO-NE Pumped Storage Hydro Operation, S-o-A forecast, 20% penetration, by shape year

Figure 5–95 shows the annual price duration comparing the 2004 shape No Wind vs. 20%_Energy Best Sites Onshore S-O-A and Perfect forecast. As can be seen in the figure, the price is typically lower for the 20% cases. The perfect forecast result is a proxy for what the PSH would be dispatched against. PSH is scheduled a week ahead and it would be based on the forecast, so when it is being scheduled it has perfect knowledge of the wind and would not change based on forecast error

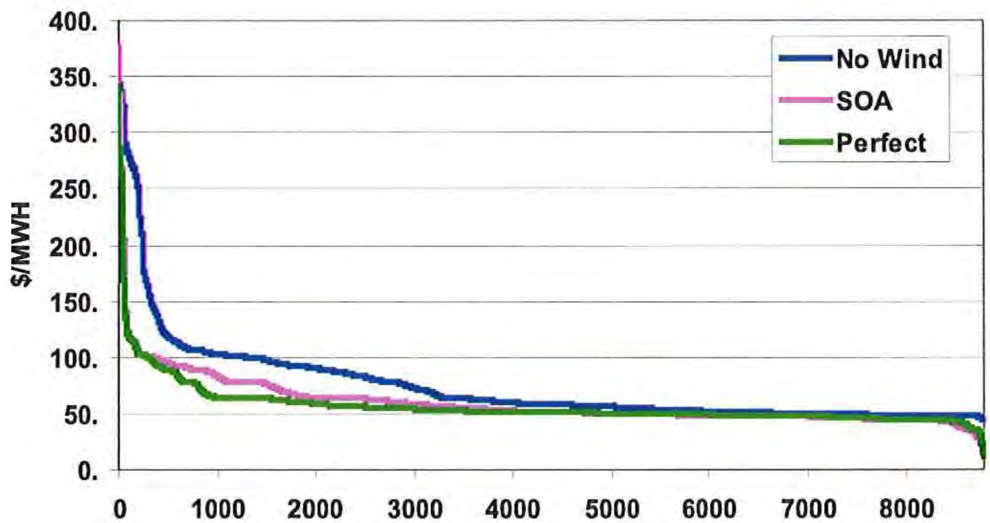


Figure 5–95 2004 shape year annual LMP duration curve comparison

Figure 5–96 shows the LMP for the three cases discussed above for the week of April 1, 2020. It also includes the wind energy for the week. As can be seen in the figure, for this week, even during the periods of lowest wind generation there is still about 1000 MW wind generation being produced. Note that the "Perfect" spot price no longer has much range for economic storage operation

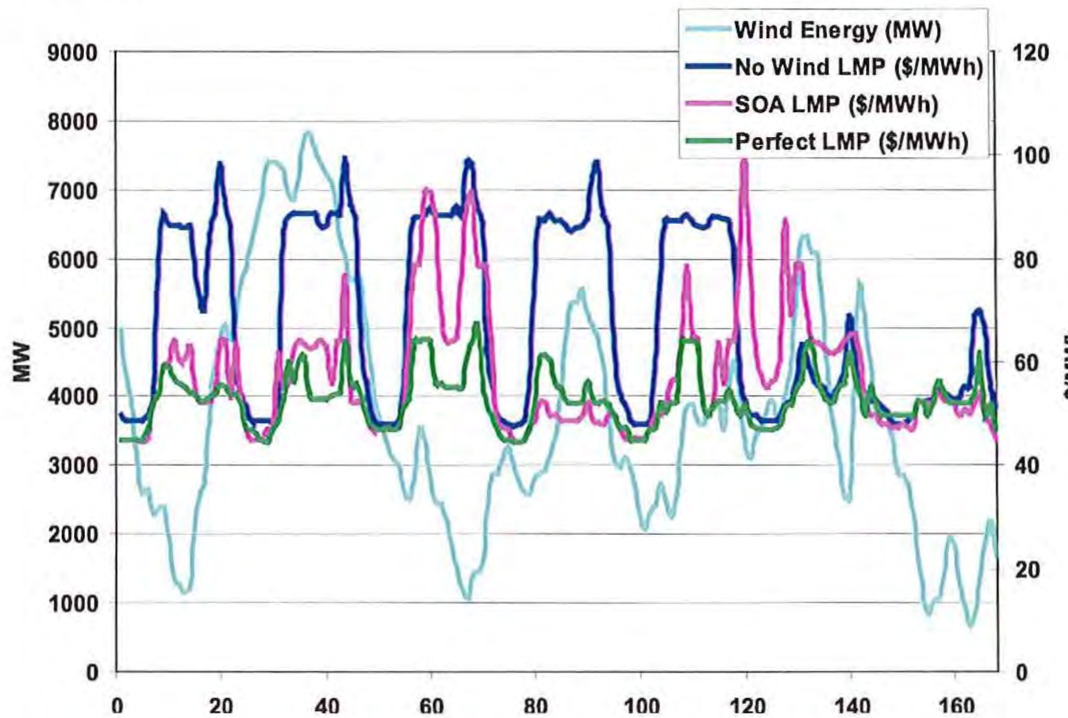


Figure 5–96 2004 shape year LMP comparison, wind energy, Week of April 1

Figure 5–97 shows the variation in the value of the wind generation as a function of shape year. Although the load energy varies, the annual variations are within a few $ MWh.

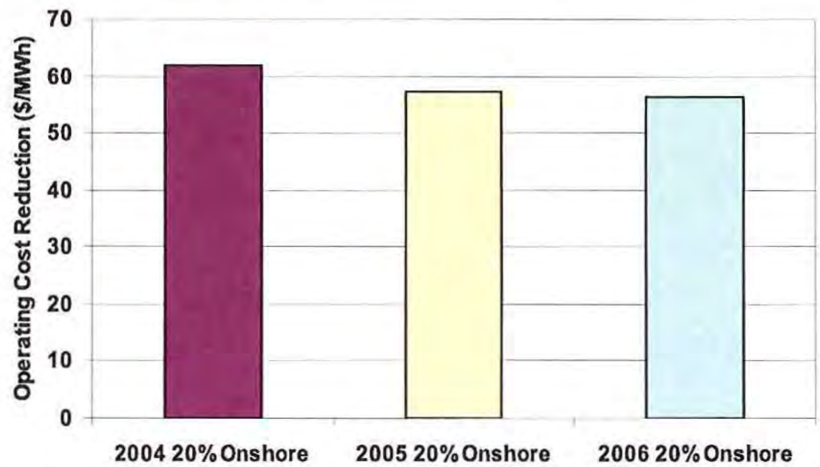


Figure 5–97 ISO-NE operating cost reduction per MWh of wind generation, S-o-A forecast, 20% Energy_ Best Sites Onshore, by shape year

Table 5–14 summarizes the number of hours that the ISO-NE interfaces were limiting or at their maximum value. The table shows the number of hours each interface was limiting, in the No Wind scenario and the 20% Energy_Best Sites Onshore scenario, for the 2020 simulation when the 2004, 2005, and 2006 load and wind shapes were used. As shown in Table 5–13, using the 2004 load shape has the highest load factor of the three years. Not surprisingly, the No Wind scenario using this shape has the highest amount of hours with the interfaces limiting. The No wind scenario using the 2005 and 2006 shapes has considerably less limiting hours. The 20% Energy_Best Sites Onshore scenarios with the different shapes have similar much lower hours limiting than the no wind. Although some hours still exist with the interfaces limiting, the Governors' 4 GW overlay was built adequately to handle the varying load amounts when using the different shape years.

Table 5–14 ISO-NE Interface Hours Limiting

Interface	2004 No wind	2005 No wind	2006 No wind	2004 20% Energy_Best Sites Onshore	2005 20% Energy_Best Sites Onshore	2006 20% Energy_Best Sites Onshore
North-South	3653	1784	1795	542	460	326
Boston Import	0	0	0	3	2	4
New England East-West	0	0	0	0	0	0
Connecticut Export	0	0	0	0	0	0
Connecticut Import	0	0	0	0	0	0
Southwestern Connecticut Import	0	0	0	0	0	0
Norwalk-Stamford Import	0	0	0	0	0	0
New York-New England	455	731	119	357	910	412
Orrington South	3026	1293	656	0	0	0
Surowiec South	81	55	37	575	410	311
Maine-New Hampshire	27	0	2	0	0	0
SEMA Export	0	0	0	0	0	0
West - East	0	0	0	0	0	0
NB - NE	631	518	283	683	523	559
SEMA/RI Export	63	0	6	0	0	0

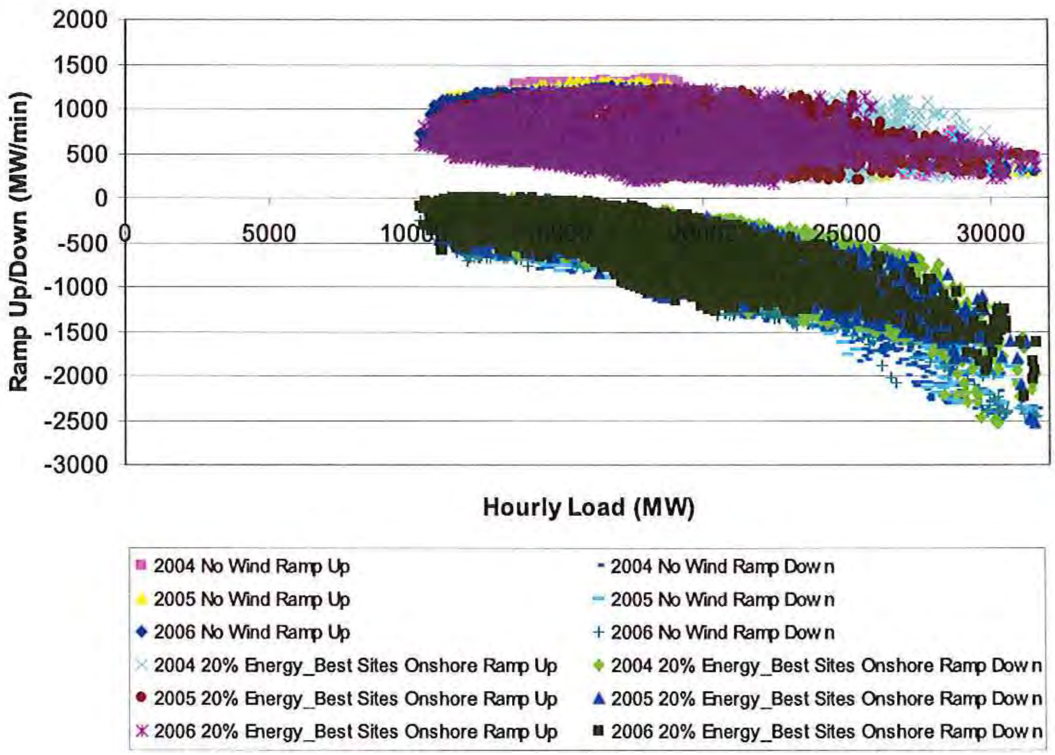
5.2.5.1 Ramp and Range Capability

Figure 5–98 compares the hourly ramp up/down capability against the hourly load for the No Wind and 20% Energy_Best Sites Onshore scenarios for the three years of shapes. The upper figure shows the total range and the bottom figure expands the graph to just show the hours with less than +/- 100 MW/min ramping capability. The ten-minute spinning reserve for ISO-NE is 700 MW, which would correspond to a ramp up capability of 70 MW/min. As can be seen from the curve, the ramp up capability never seems to be a problem. The regulation requirement at the 20% wind penetration level is roughly 400 MW (see section 4.4.1). Again, from the ramp up side this doesn't appear to present any difficulty. However, the ramp down capability is deficient several hundred hours and may possibly require either changes to the unit commitment or spilling of some wind energy.

Table 5–15 shows a summary of the number of hours with less than 100 MW/min of ramp down capability for the six cases shown. While none of the No Wind cases showed any hours with the ramp down capability less than 100 MW/minute there was considerable differences between the three years for the 20% cases.

Table 5–15 Number of hours with ramp down capability < 100 MW/minute, various study years.

Scenario	# Hours
2004 No Wind	0
2005 No Wind	0
2006 No Wind	0
2004 20% Energy_Best Sites Onshore	103
2005 20% Energy_Best Sites Onshore	208
2006 20% Energy_Best Sites Onshore	374



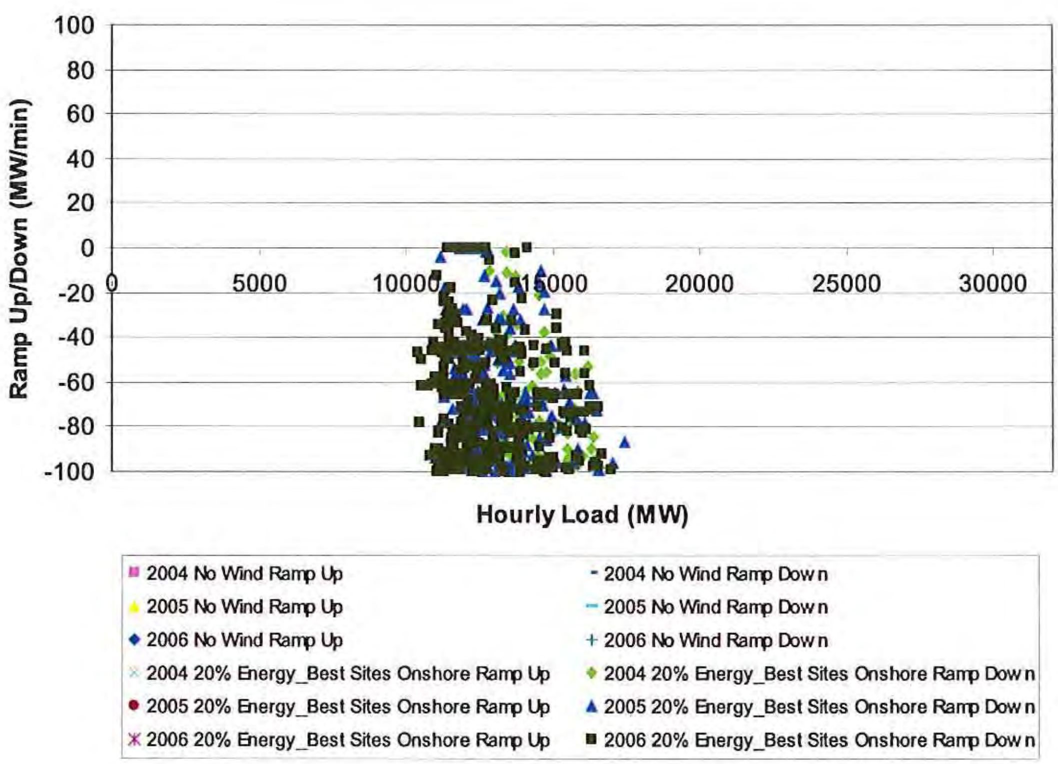


Figure 5–98 Hourly Ramp Up/Down vs. Load, Shape Year Comparison

5.3 Additional Operational Sensitivities

The following section looks at various sensitivities. All sensitivities were done using the No Wind and 20% Energy_Best Sites Onshore scenario or 20% Energy_Best Sites Maritimes scenarios. All were paired with their corresponding constrained transmission configuration (i.e. 2019 ISO-NE and 4 GW Governors overlay) full transmission and the 20% Energy_Best Sites Onshore and 20% Energy_Best Sites Maritimes scenario used a S-o-A wind forecast.

5.3.1 Carbon Price Sensitivity

The following section analyzes the impacts of adding a carbon cost to the entire system studied. The 20% Energy_Best Sites Onshore case, which contains no carbon cost, was compared to the identical case with a \$40/ton of CO2 and \$65/ton of CO2 cost adder to observe the impacts of carbon prices on the New England bulk power system. In addition, the same analysis was performed on the No Wind case.

Figure 5–99 shows the generation by type for the 20% Energy_Best Sites Onshore case, the No Wind case, and these cases with both a \$40/ton and \$65/ton carbon cost added.

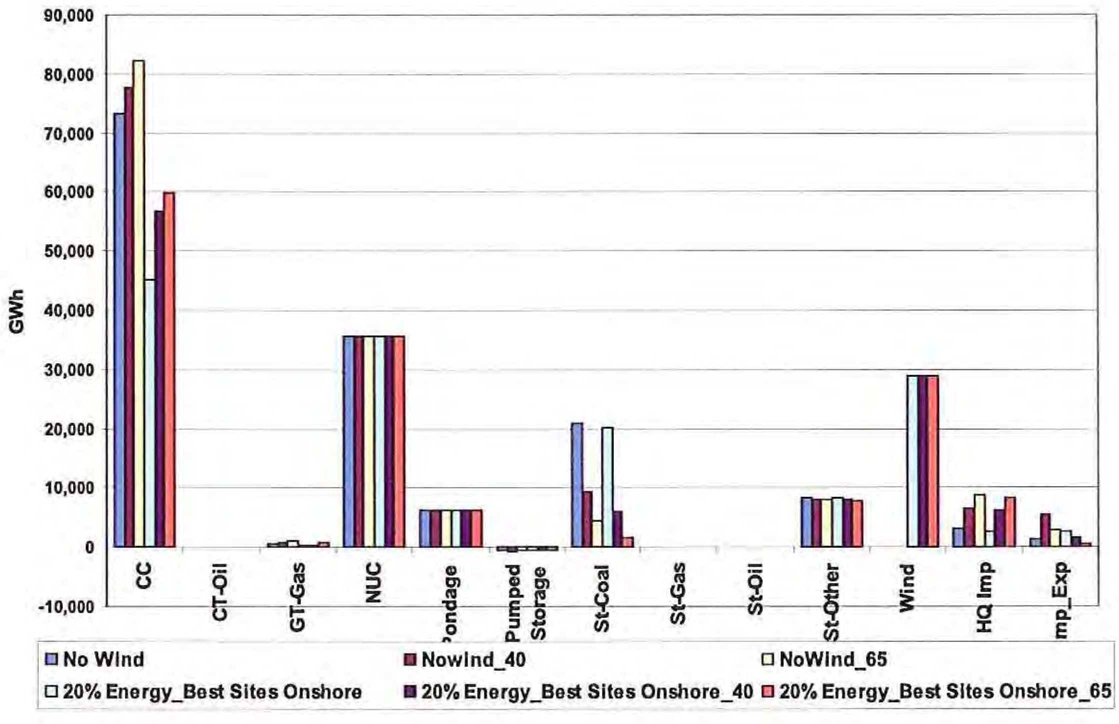


Figure 5–99 Carbon cost impact on ISO-NE generation by type

In both scenarios, it can be seen in the figure that St-Coal generation is largely displaced by combined cycles as the carbon cost increases. Steam-coal units produce approximately 1 ton of

CO_2 per MWh of energy vs. approximately 0.6ton tons of CO_2 per MWh of energy for gas fired units. Because of the much higher efficiencies possible with combined cycle generation these resources may emit 0.4 tons/MWh of CO_2. The additional costs due to carbon prices on coal-fired units vs. gas-fired units will force coal to be above the margin on a more regular basis, and operate less frequently. It can also be seen that imports, particularly those from HQ where no carbon cost was added, increase along with the carbon cost due to the higher prices in ISO-NE. In the scope of this study, it was not possible to analyze the dynamics of a carbon cost on the price of fuels that may increase the cost of gas and decrease the delivered price of coal.

Figure 5–100 compares the full load costs for cc's and St-Coal units given no carbon cost and a \$40/ton carbon cost, with respect to gas price. Given an average Full Load Heat Rate (FLHR) or average heat rate at the unit's maximum operating point by type of unit and a \$2.86/ton coal price, it can be seen that the full load cost for a CC unit will be lower than that of St-Coal unit when gas prices drop to approximately \$4/MMBTU. Under a \$40/ton CO_2 policy and the same delivered coal price assumption, the effective coal dispatch price would increase from \$30/MWh to \$70/MWh. The gas price would only need to drop to approximately \$6.25/MMBTU for a CC to have a lower full load cost than a St-Coal unit. Some displacement occurs at higher gas prices because the incremental heat rates of a CC and St-Coal units have a great deal of variation displacement of St-Coal can be seen with the increase in Carbon price in Figure 5–99.

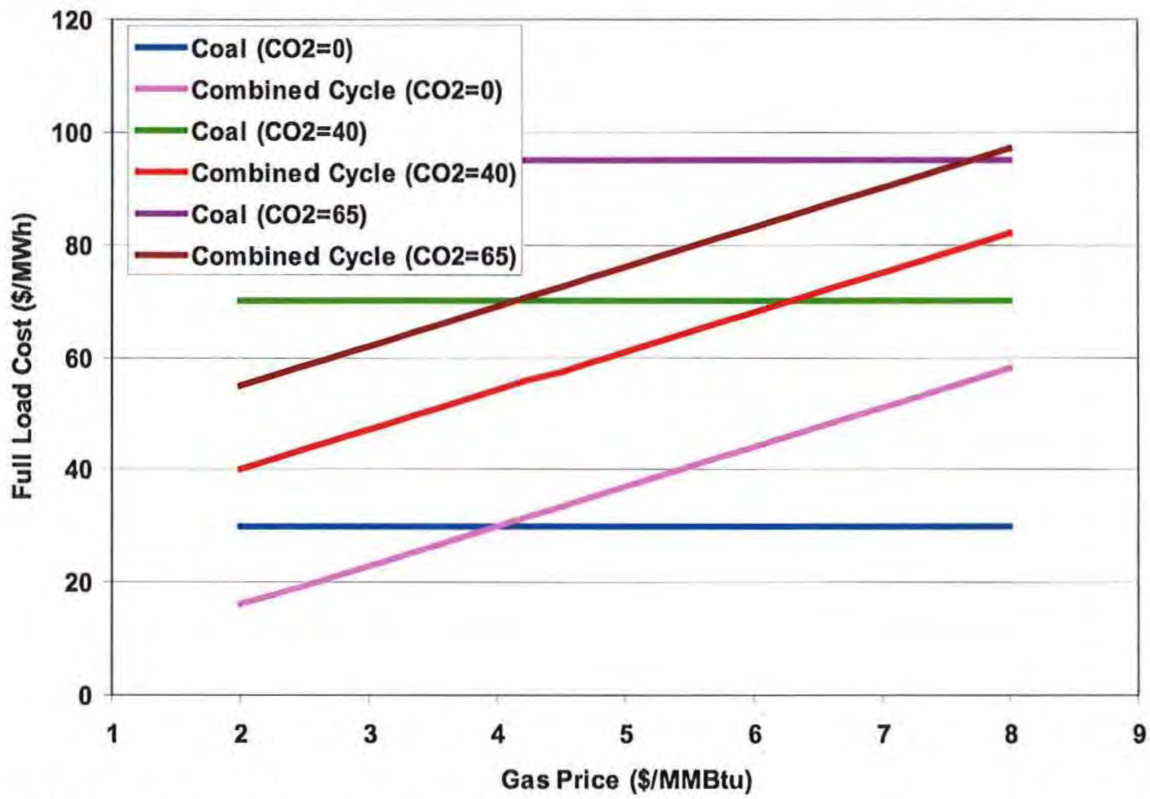


Figure 5–100 Steam Coal vs. Combined cycle full load variable cost

The revenue by type comparison is shown in Figure 5–101. As expected, the largest increase in revenue occurs for the CC generation. This is mainly due to the additional generation shown in Figure 5–99 and the higher prices in ISO-NE due to the carbon cost. Other types of generation unaffected by the carbon cost, such as wind and nuclear also have revenue gains due to higher ISO-NE prices.

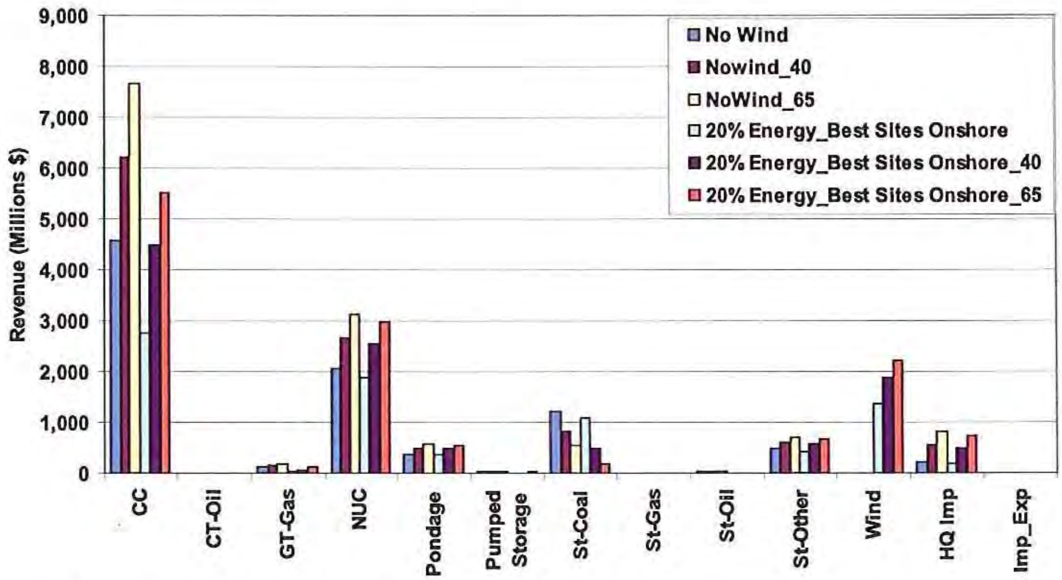


Figure 5–101 Carbon cost impact on ISO-NE revenue by type

Figure 5–102 compares the value of the wind generation between the original and carbon cost scenarios. Wind energy becomes more valuable as the price of carbon increases due to the increased costs for CO2 emitting generation, while wind costs remain unchanged. A $65/ton carbon cost increases the value of the wind by over $30/MWh.

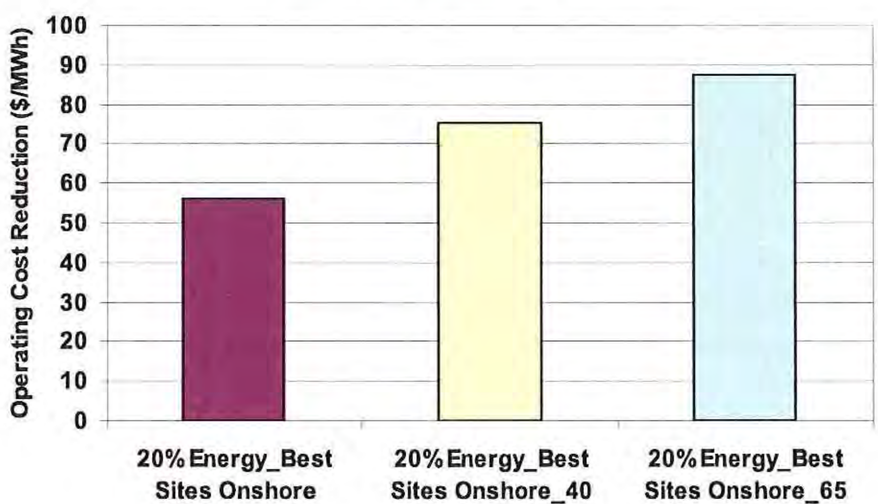


Figure 5–102 Carbon cost impact on ISO-NE operating cost reduction per MWh of wind generation

Figure 5–103 compares the LMP duration for the six scenarios. The No Wind cases increase in price with the addition of a carbon cost. The 20% Energy_Best Sites Onshore results are similar.

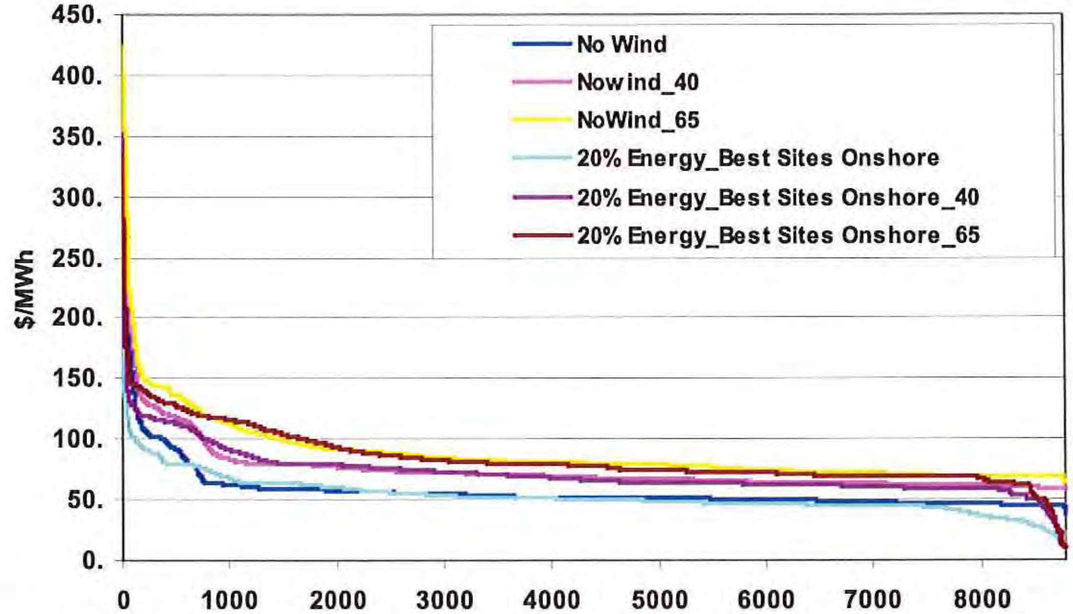


Figure 5–103 Carbon cost impact on ISO-NE annual LMP duration curve

Figure 5–104 compares the weighted average annual LMP for ISO-NE. As implied in Figure 5–102, as the carbon cost increases, LMPs increase substantially.

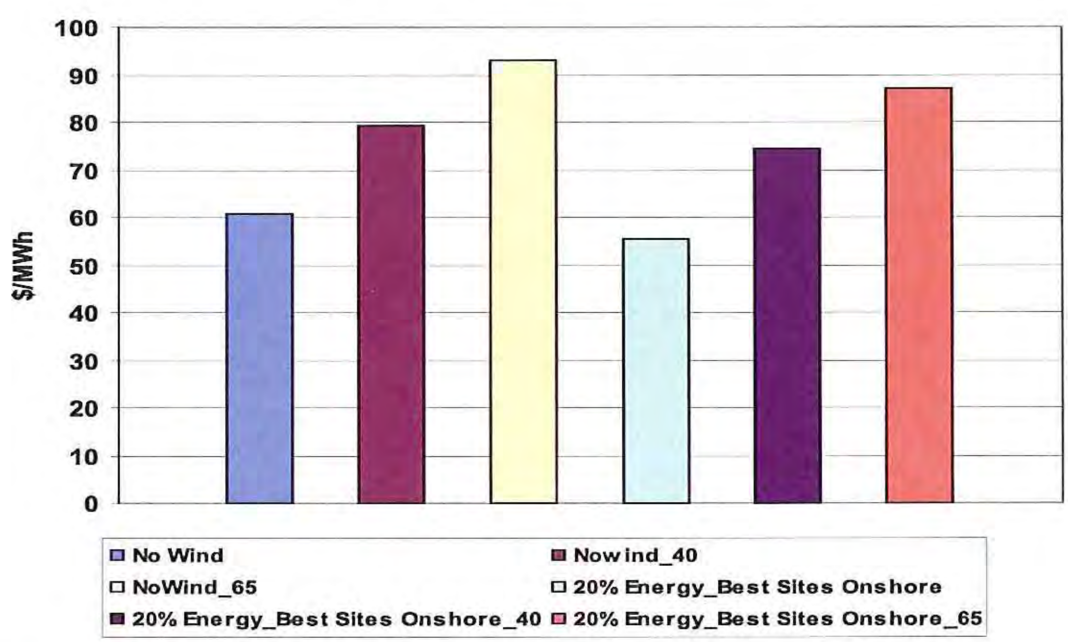


Figure 5–104 Carbon cost impacts on annual load weighted average ISO-NE LMP

Figure 5–105 below shows the ISO-NE emissions for each scenario. Due to the large decreases in coal plant production, SOx output drops off significantly. As expected, CO2 output also drops as the carbon cost increases.

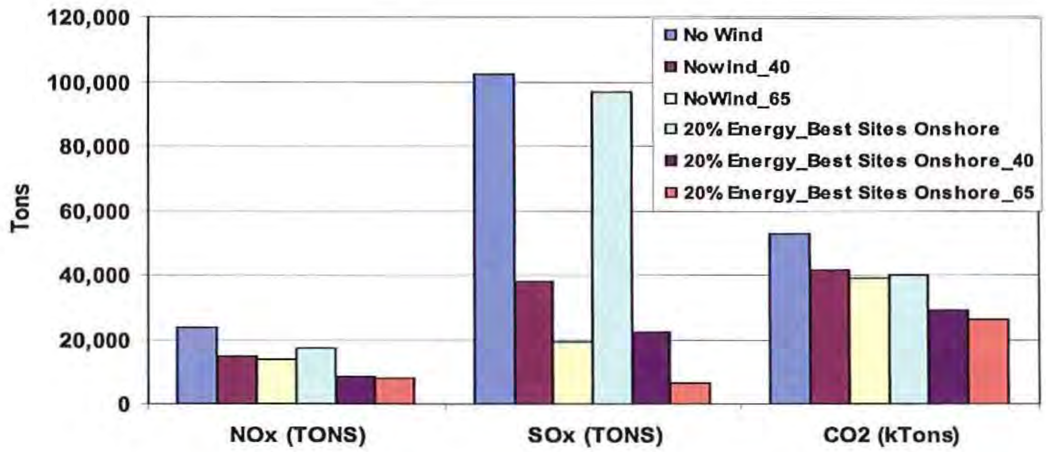


Figure 5–105 Carbon cost impact on ISO-NE emissions

5.3.2 Fuel Price Sensitivity

In addition to the CO2 sensitivities, a fuel price sensitivity taking into account carbon cost was also analyzed. The No Wind and 20% Energy_Best Sites Onshore with $65/ton carbon cost were modeled with a higher and lower fuel price for all types of fuel. In the high fuel price scenario, gas, oil, and coal were each doubled. In the low fuel price scenario, the price of each fuel was reduced by 25%.

Figure 5–106 shows the ISO-NE generation by type for each of the six scenarios. In the low fuel case, gas prices are reduced by $2/MMBTU in ISO-NE while coal is reduced by approximately $.70/ton in the same area. It can be seen that CC units increase their output and displace nearly all St-Coal units due to the combination of impacts from the $65/ton carbon policy and the reduced fuel prices. The high fuel case results in a gas price increase of $8/MMBTU and a coal price increase of approximately 3$/ton. The large increase in costs for gas-fired units allows St-Coal to partially displace CC generation.

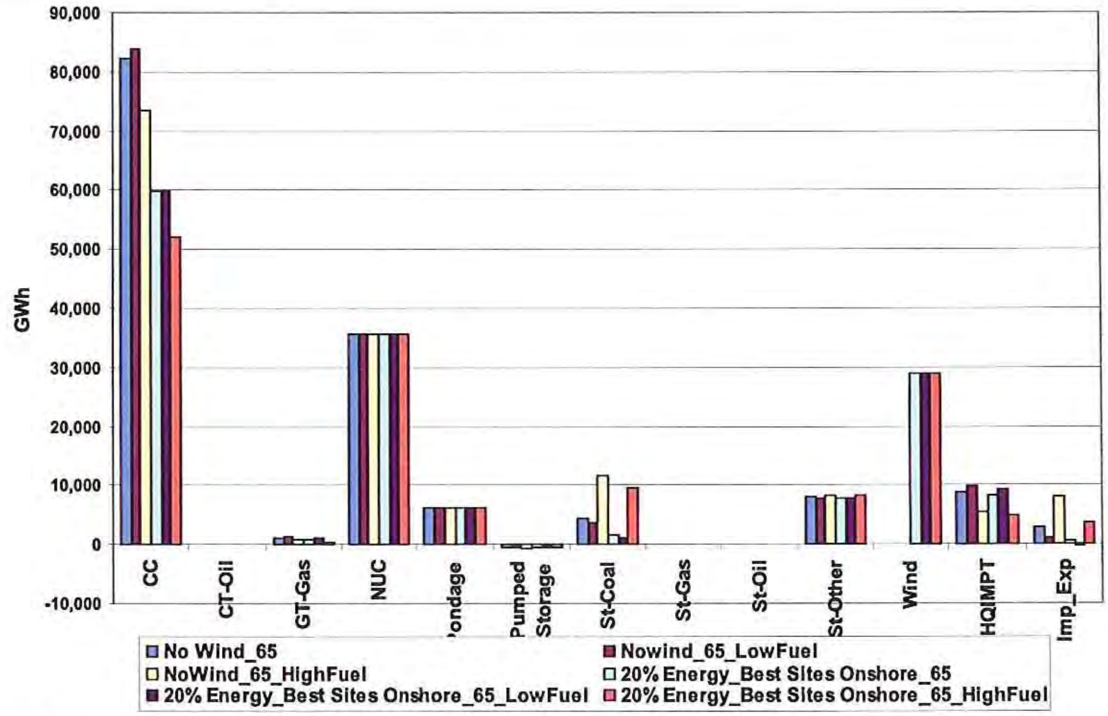


Figure 5–106 Fuel price impact on ISO-NE generation by type

Figure 5–107 shows the ISO-NE revenue by type of unit, while Figure 5–108 shows the ISO-NE total variable cost by type. As the fuel price increases, revenue increases due to higher spot prices; however, total variable cost for non-nuclear thermal generation is also driven up by the increase in fuel price.

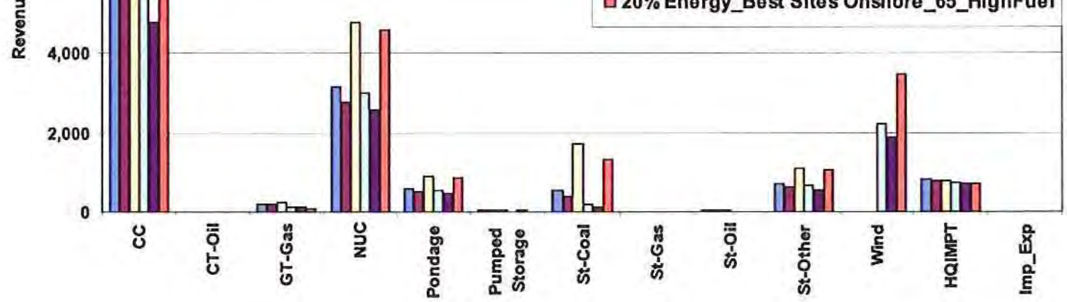


Figure 5–107 Fuel price impact on ISO-NE revenue by type

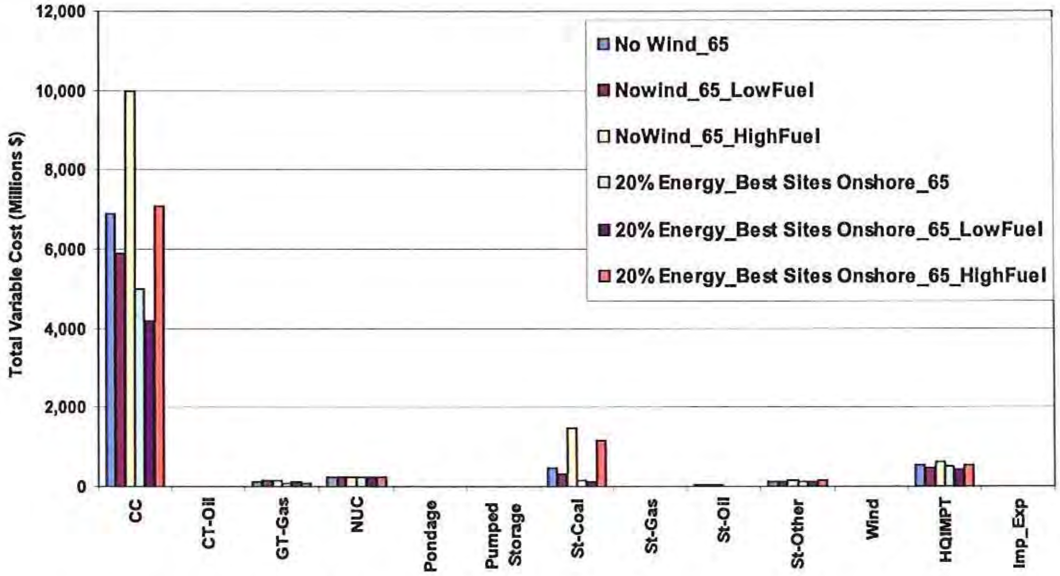


Figure 5–108 Fuel price impact on ISO-NE total variable cost by type

Figure 5–109 shows the annual load weighted average LMP for ISO-NE. In the No Wind case, the decrease in fuel costs under the low fuel scenario decreases the price, but only partially counteracts the price increase due to the carbon policy. The high fuel scenario raises prices, and in combination with the carbon policy, results in the highest average LMP's. The Onshore cases show similar results.

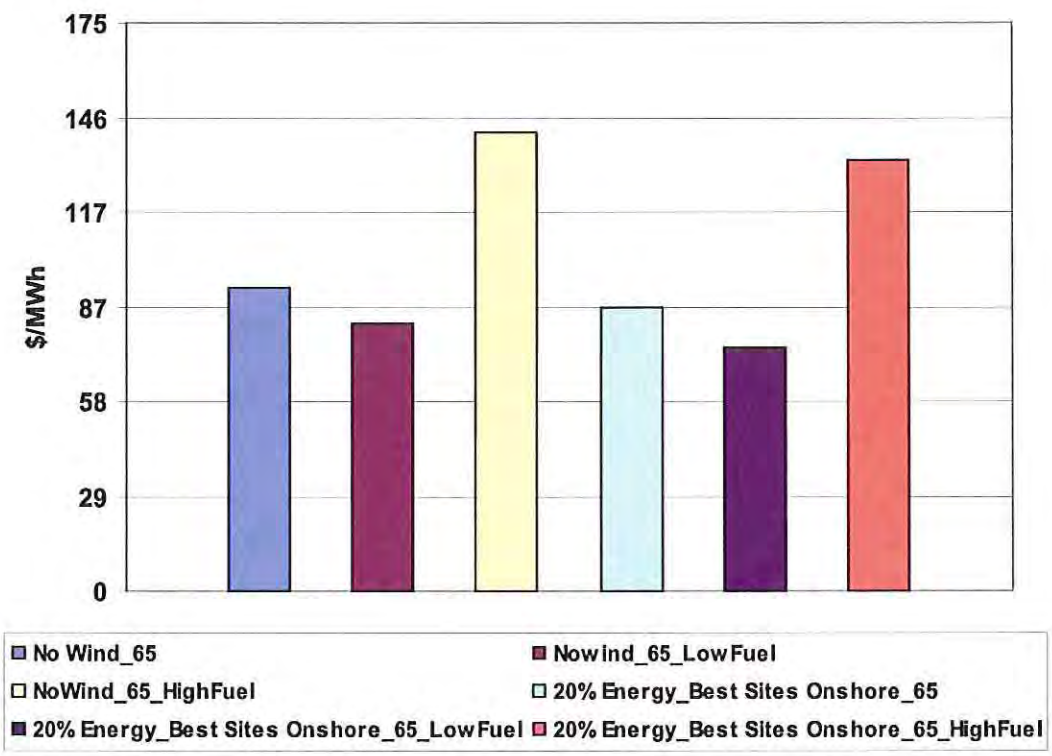


Figure 5–109 Fuel price impacts on annual load weighted average ISO-NE LMP

5.3.3 Load Forecast Uncertainty Sensitivity

The following sensitivity looked at how including an imperfect load forecast with a S-o-A wind forecast for the ISO-NE system would change operations. This was done only for ISO-NE. The other regions had perfect knowledge of the hourly load but used a S-o-A wind forecast. The 2006 ISO-NE load forecast error was used as an adder to the 2006 RSP zonal extrapolated load for the commitment phase of the MAPS model. The load forecast error was determined by comparing the 2006 ISO-NE day-ahead load forecast to the 2006 Actual load[73]. The actual 2006 extrapolated load and wind was used for the dispatch.

It is important to analyze the effect an imperfect load forecast has on the system as well as an imperfect wind forecast. Forecasts are not perfect and contain errors. The load forecast error might be additive or balance out the wind forecast error. Therefore introducing an imperfect load forecast increases the complexity of operating the system.

This analysis assesses the impacts of load forecast error combined with wind forecast error and the resulting impacts. Figure 5–110 shows duration curves for the 2020 load forecast, actual load, wind forecast, actual wind, the net load forecast, and actual net load that were used in the simulation.

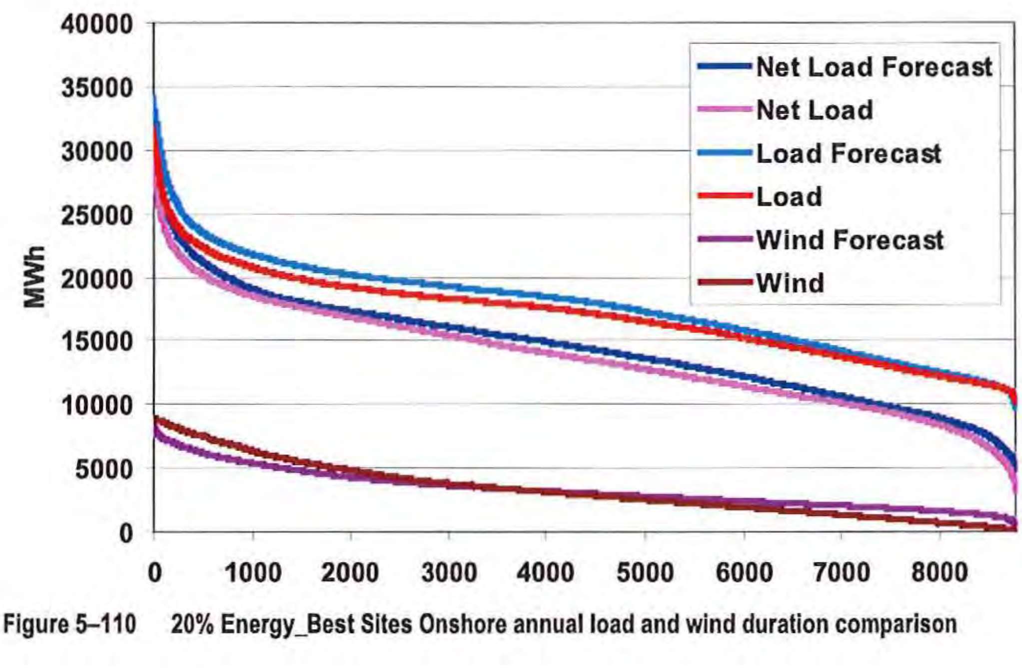


Figure 5–110 20% Energy_Best Sites Onshore annual load and wind duration comparison

[73] http://www.iso-ne.com/markets/hstdata/znl_info/hourly/2006_smd_hourly.xls

Figure 5–111 shows, for the month of April, the hourly load forecast, actual load, wind forecast, and actual wind. The load forecast is higher during most the peak hours, but the wind forecast is typically lower. The higher peak load forecast likely represents a bias applied by the ISO to reliably operate the system during these times.

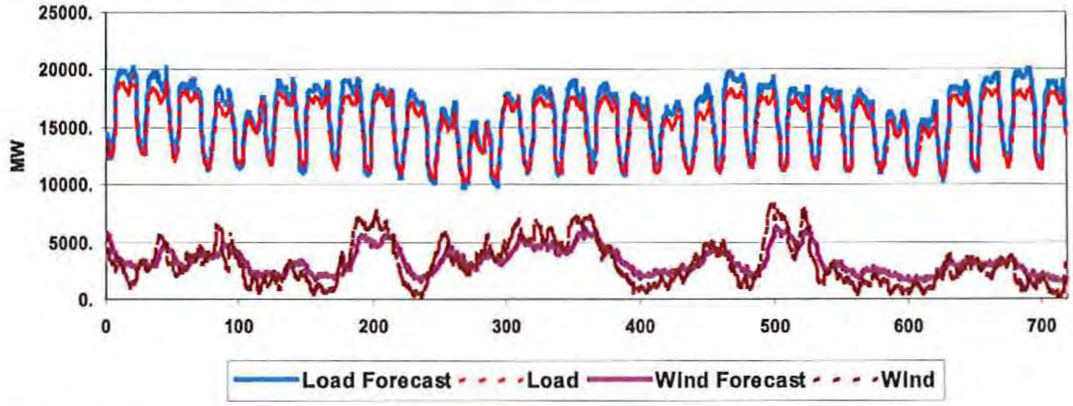


Figure 5–111 20% Energy_Best Sites Onshore annual load and wind comparison, month of April

Figure 5–112 compares the generation by type for ISO-NE for the No Wind, the No Wind using the (imperfect) load forecast, 20% Energy_Best Sites Onshore with S-o-A wind forecast, and 20% Energy_Best Sites Onshore with S-o-A wind forecast and (imperfect) load forecast. The load forecast impacts the CC generation. As shown in Figure 5–111, the load forecast is typically higher than the actual load. This causes an over commitment of generation, primarily CC units. The effect of the load forecast causes an additional 12 GWh of wind curtailment. This equates to 0.04% of the annual wind energy produced in the 20% Energy_Best Sites onshore case with load forecast error.

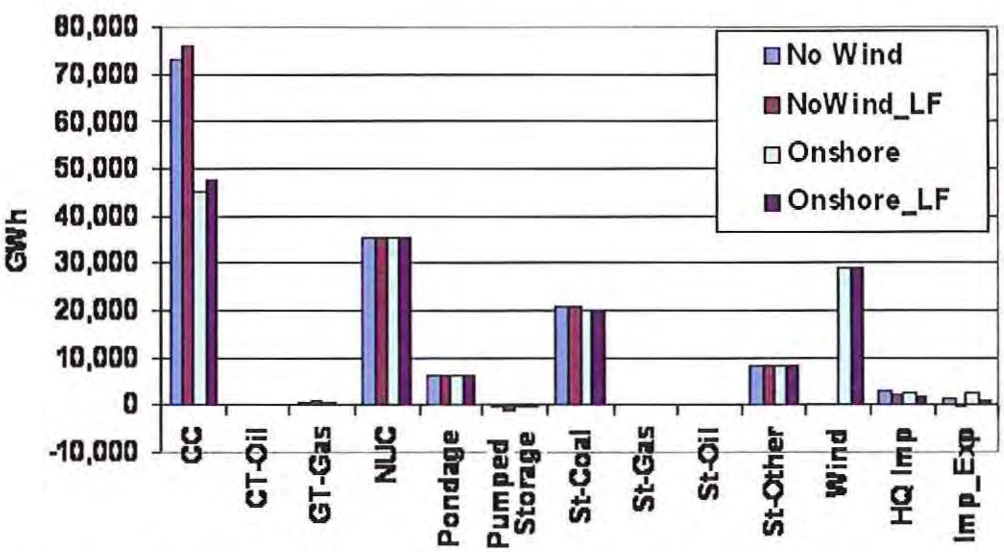


Figure 5–112 Load forecast impact on ISO-NE generation by type

The over commitment of the CC units impacts the total ISO-NE emissions as seen in Figure 5–113. The NOx and CO2 are higher in the load forecast cases than the cases without load forecast uncertainty (i.e. the cases with perfect load forecasts). The over commitment of the CC generation backs the CC units down to lower operating points during the dispatch to a less efficient operating point on their average heat rate curve and therefore produce higher emission amounts.

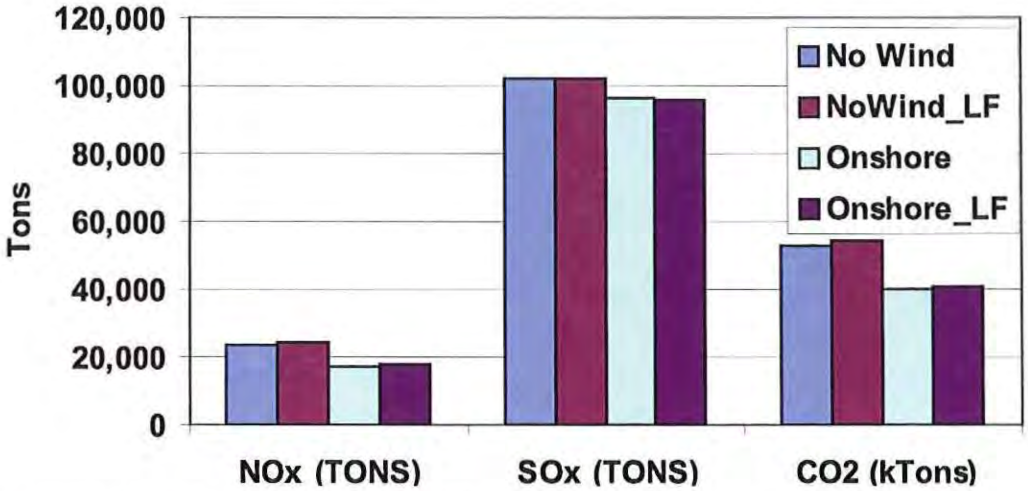


Figure 5–113 Load forecast impact on ISO-NE emissions

Figure 5–114 compares the load-weighted average LMP for ISO-NE. The price is lower in the cases that have load forecast error built into them. Although CC units are backed down to a less efficient lower operating point, the incremental cost is lower. Therefore, average LMP is reduced.

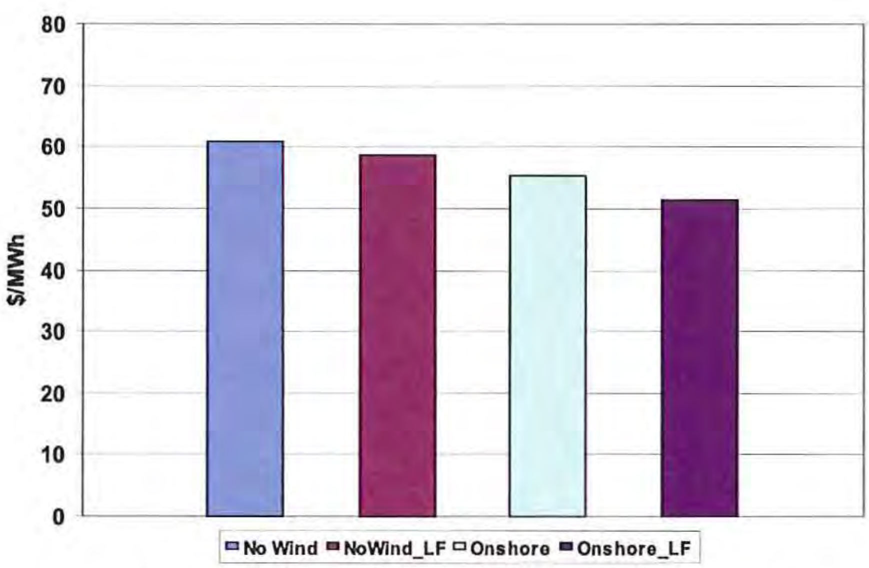


Figure 5–114 Load forecast impact on annual load weighted average ISO-NE LMP

The revenue by type is reflected in Figure 5–115. The revenue is lower for most of the generation. The CCs revenue is slightly higher because of the increased operation.

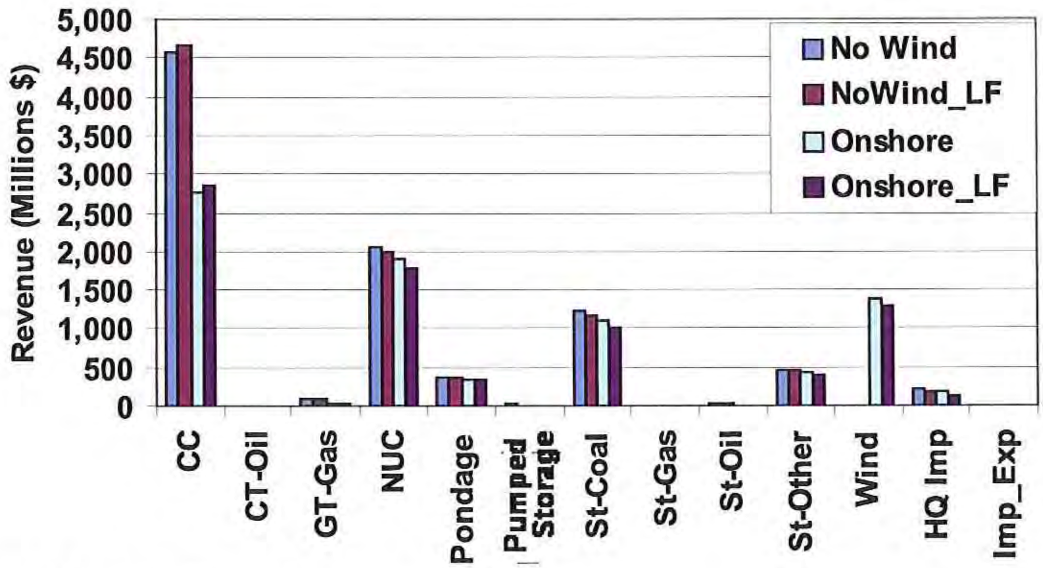


Figure 5–115 Load forecast impact on ISO-NE revenue by type

Figure 5–116 compares the value of the wind for the case with and without forecast error. The value is also included for a case with perfect load knowledge and a perfect wind forecast. With perfect knowledge, the wind has a value of $58/MWh to $55/MWh when a load forecast error is assumed and a S-o-A wind forecast is used.

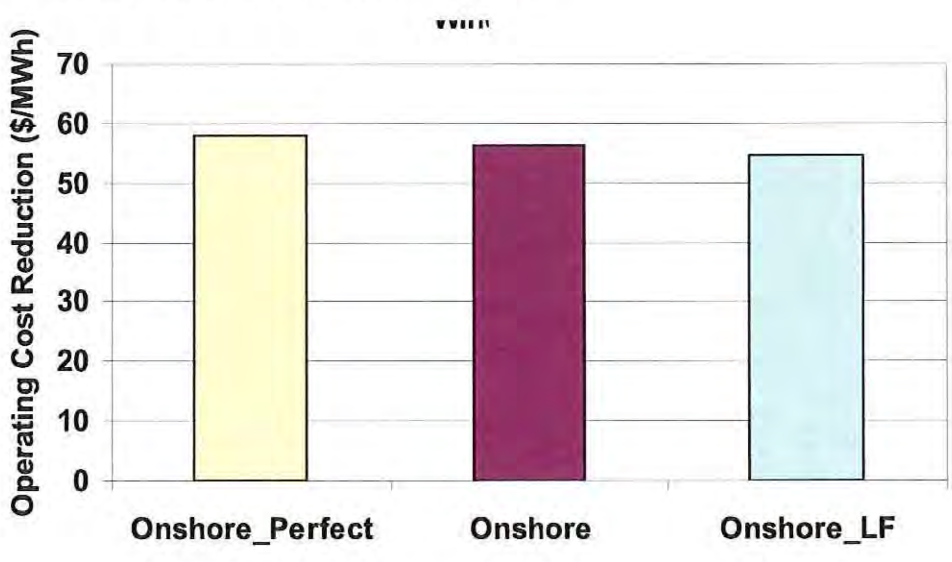


Figure 5–116 Load forecast impact on ISO-NE operating cost reduction per MWh of wind generation

5.3.4 Maritimes Interface Expansion Sensitivity

The following section compares the impact of quadrupling the import/export capability from the Maritimes to ISO-NE. The Maritimes to ISO-NE interface was raised from 500 MW/-1000 MW to 2000 MW/-4000 MW. The 20% Energy_Best Sites Maritimes scenario was evaluated.

Figure 5–117 shows the generation by type for the No Wind, No Wind with quadruple import capability from the Maritimes, 20% Energy_Best Sites Maritimes, and 20% Energy_Best Sites Maritimes with quadruple import capability from the Maritimes. The comparison of the No Wind and 20% Energy_Best Sites Maritimes scenarios show the increased interface limits result in a small change in imports. It is important to note that the Maritimes wind generation was counted in the "wind" category and not the "imports." Combined Cycles are displaced within New England in the No Wind sensitivity case to account for the additional imports. Gas turbines also run slightly more in the No Wind sensitivity as NE exports more to the Maritimes in the winter months during which the Maritimes has its peak load season. The 20% Energy_Best Sites Maritimes with increased limits results in ISO-NE importing slightly more energy than the 20% Energy_Best Sites Maritimes case in addition to the wind.

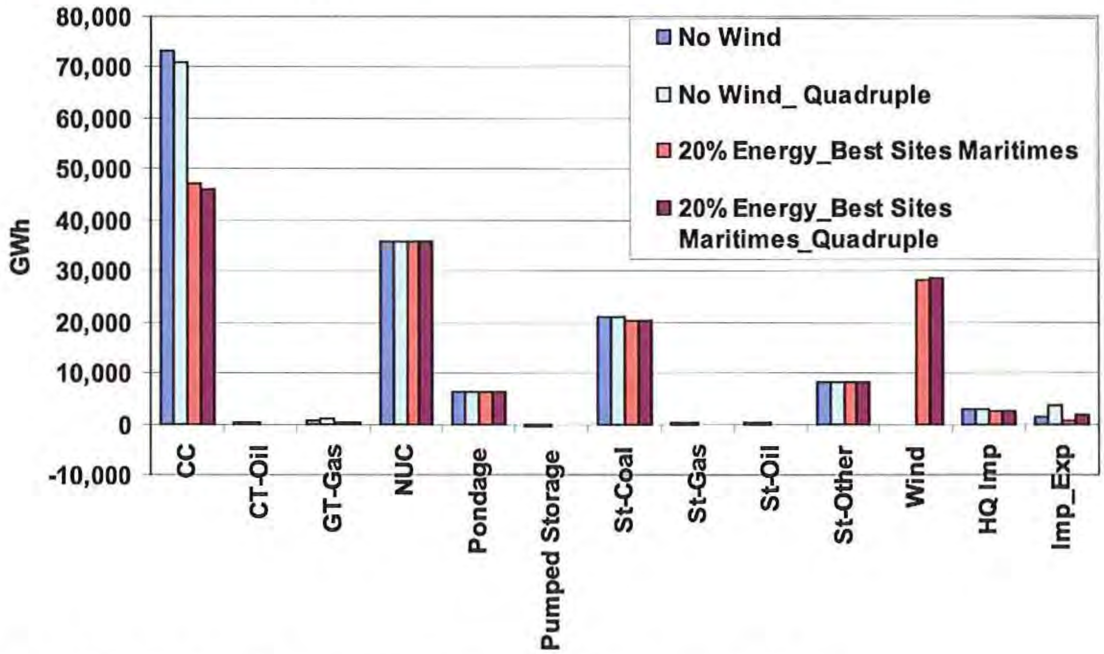


Figure 5–117 Maritimes interface expansion impact on ISO-NE generation by type

The revenue by type comparison is shown in Figure 5–118. Due to the increased seasonal exports in the No Wind case, ISO-NE prices are slightly higher on an annual basis. With the change in interface flows, NB prices are reduced, also reducing total system cost. These higher prices in ISO-NE result in higher revenues for all types of generation. A similar result can be seen for the 20% Energy_Best Sites Maritimes cases.

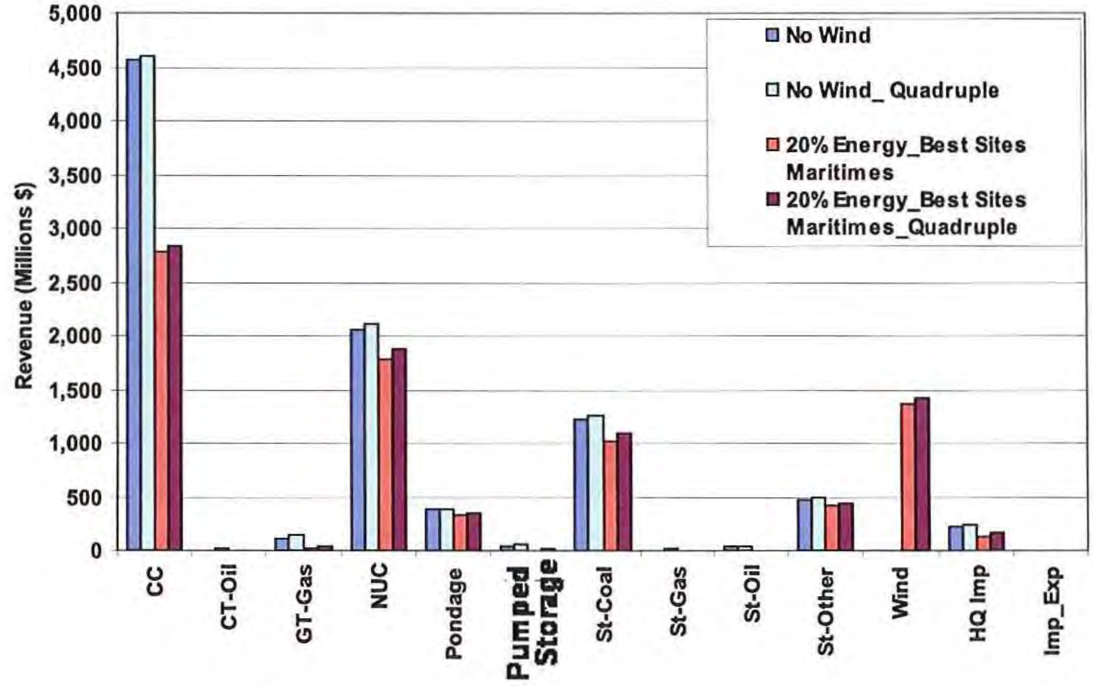


Figure 5–118 Maritimes interface expansion impact on ISO-NE revenue by type

Figure 5–119 compares the value of the wind generation between the original and quadruple import/export capability scenario. The value is similar between the two scenarios; however, wind becomes slightly more valuable, about $1/MWh more valuable.

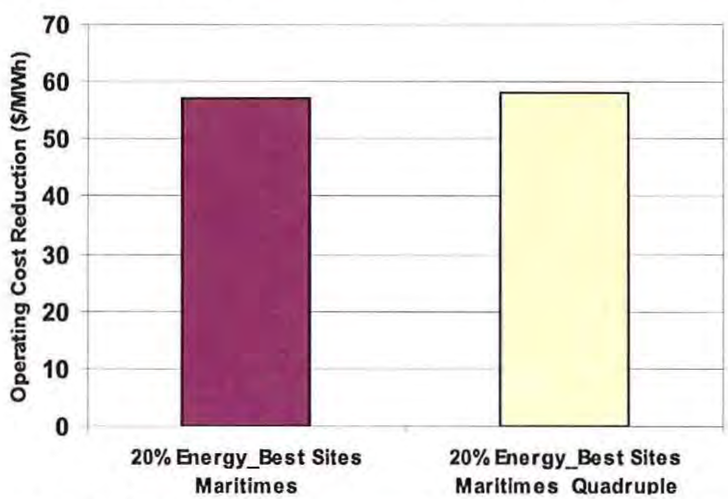


Figure 5–119 Maritimes interface expansion impact on ISO-NE operating cost reduction per MWh of wind generation

Quadrupling the interface limits from ISO-NE to the Maritimes reduces wind curtailment from 328.65 GWh in the 20% Energy_Best Sites Maritimes to 11.08 GWh in the 20% Energy_Best Sites Maritimes_Quadruple scenario.

Figure 5–120 compares the flow duration on the ISO-NE to Maritimes interface for the four scenarios. Note that negative flow, is flow from the Maritimes to ISO-NE. The No Wind with quadruple import/export capability has more exports to the ISO-NE and less imports to Maritimes. The 20% Energy_Best Sites Maritimes with quadruple interface limits exports more than 20% Energy_Best Sites Maritimes scenario to ISO-NE.

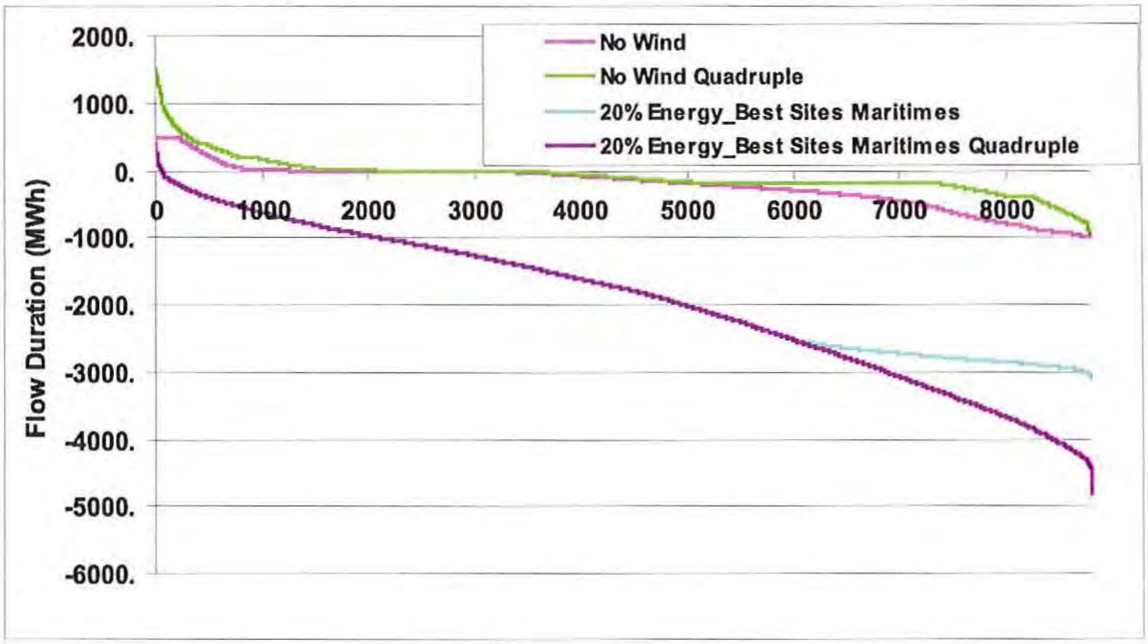


Figure 5–120 ISO-NE to Maritimes interface flow comparison

Quadrupling the interface limits to the Maritimes has minimal impact on the ISO-NE system. The cost of the transmission expansion would likely out-weigh the impacts.

5.3.5 ISO-NE Interface Sensitivity

The following section compares the impact of doubling the import/export capability from NY, Maritimes, and Hydro Quebec to ISO-NE. The NY to ISO-NE AC interface was raised from +-1,600 MW to +-3,200 MW. The Maritimes to ISO-NE interface was raised from 500 MW/-1000 MW to 1000 MW/-2000 MW. The HQ Import capacity was increased from 1,600 MW to 3,200 MW.

Figure 5–121 shows the generation by type for the No Wind, No Wind with double import capability, 20% Energy_Best Sites Onshore, and 20% Energy_Best Sites Onshore with double import capability. The comparison of the No Wind and 20% Energy_Best Sites Onshore scenarios show the net increased imports displace the CC generation. The HQ imports roughly double. In the No Wind with double import capability, the imp/exp flips. The 20% Energy_Best Sites Onshore with double import capability the imp/exp remains roughly the same as the 20% Energy_Best Sites Onshore.

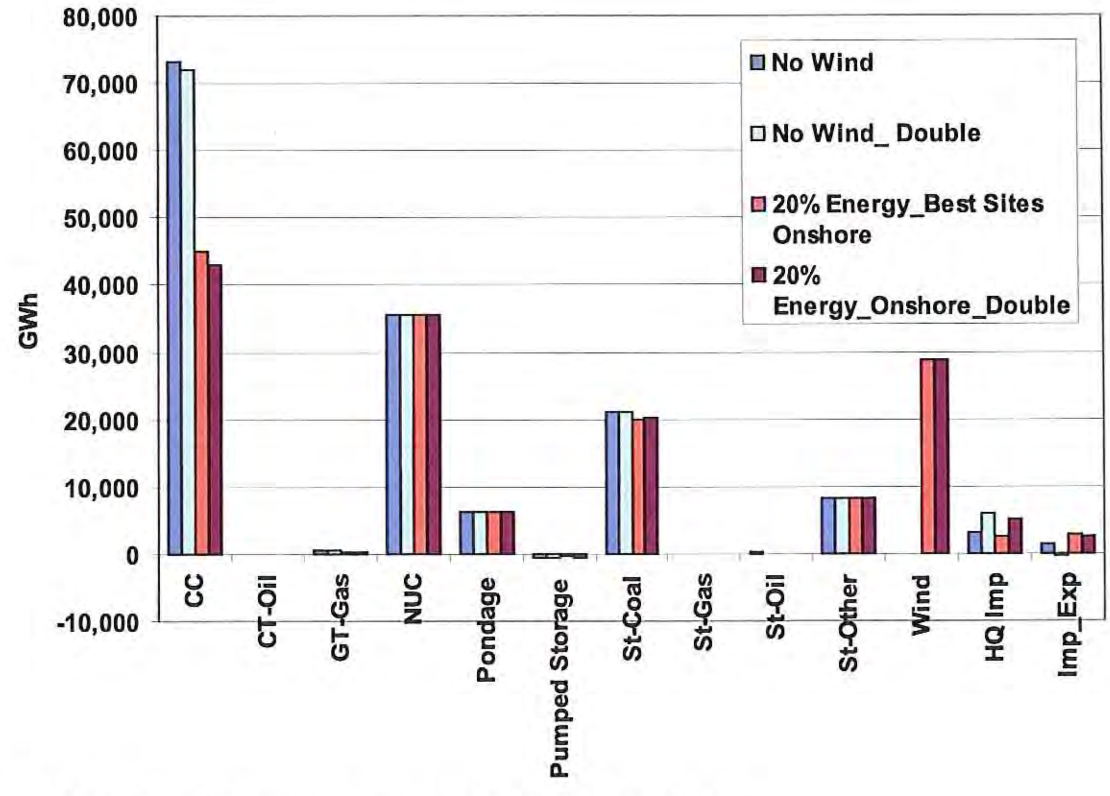


Figure 5–121 Interface expansion impact on ISO-NE generation by type

The revenue by type comparison is shown in Figure 5–122. As expected, the largest decrease in revenue occurs to the CC generation. This is because of the displacement shown in Figure 5–121.

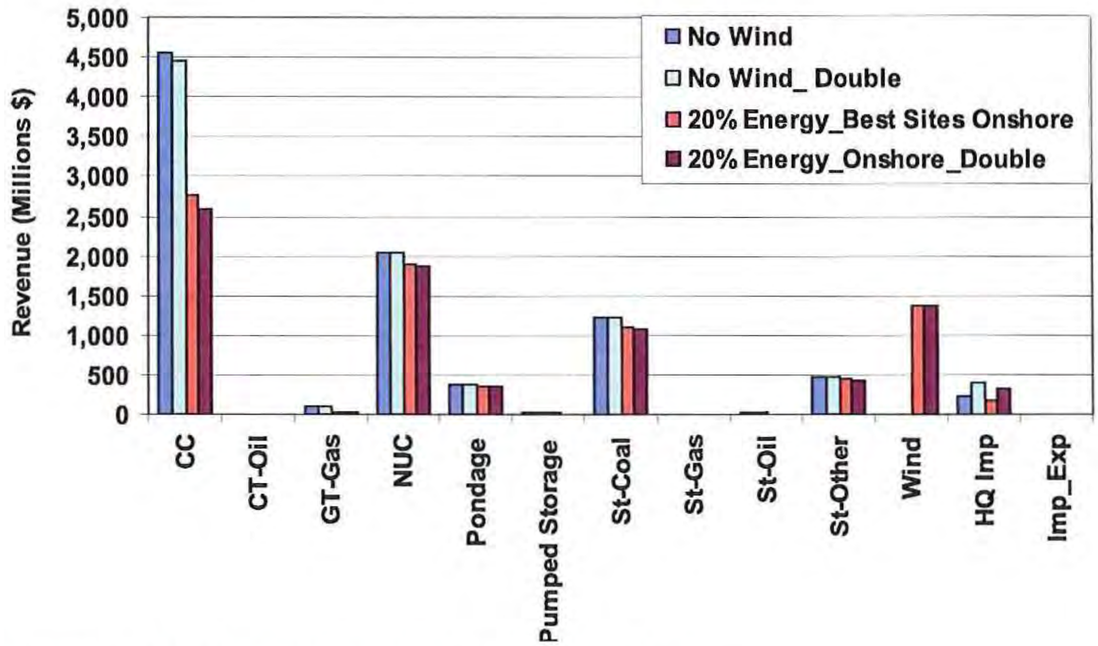


Figure 5–122 Interface expansion impact on ISO-NE revenue by type

Figure 5–123 compares the value of the wind generation between the original and double import/export capability scenario. Doubling the import capability reduces the operating cost for ISO-NE slightly more and therefore adds more value to the wind, about $1/MWh.

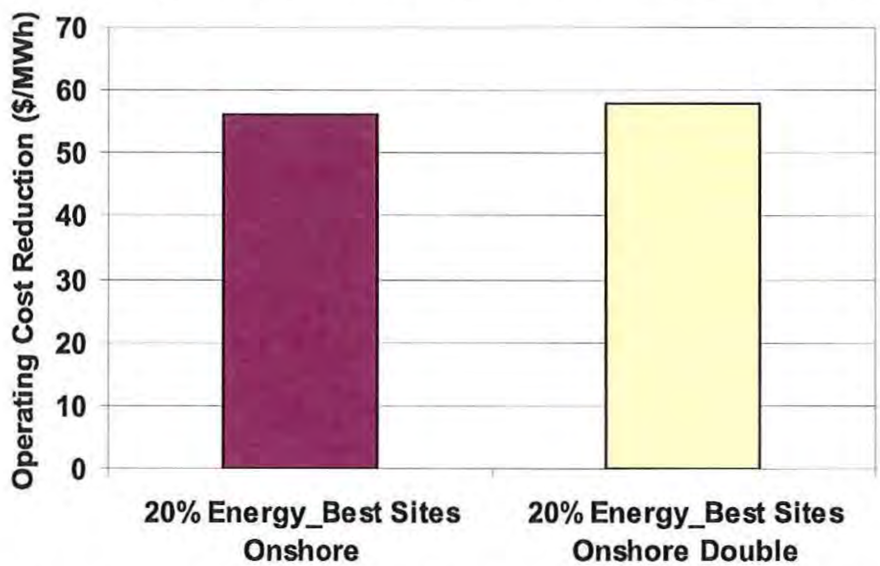


Figure 5–123 Interface expansion impact on ISO-NE operating cost reduction per MWh of wind generation

Figure 5–124 compares the flow duration on the ISO-NE to Maritimes interface for the four scenarios. The No Wind with double import/export capability has more exports to the Maritimes and less imports to ISO-NE. The two 20% Energy_Best Sites Onshore are similar.

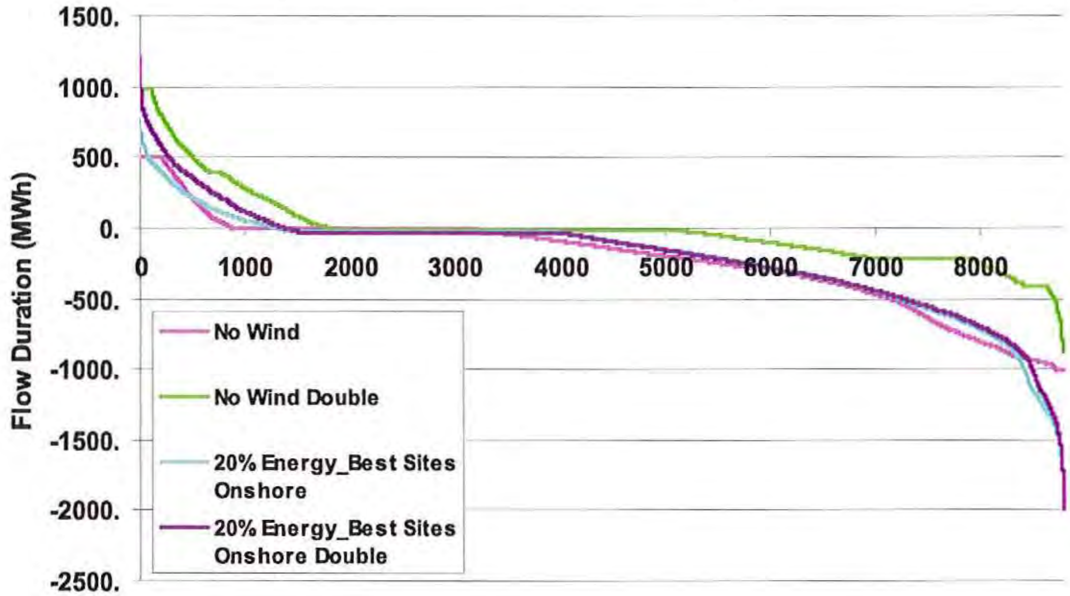


Figure 5–124 ISO-NE to Maritimes Interface flow comparison

Figure 5–125 compares the flow duration on the ISO-NE to NY interface for the four scenarios. There is practically no impact by doubling the import/export capability.

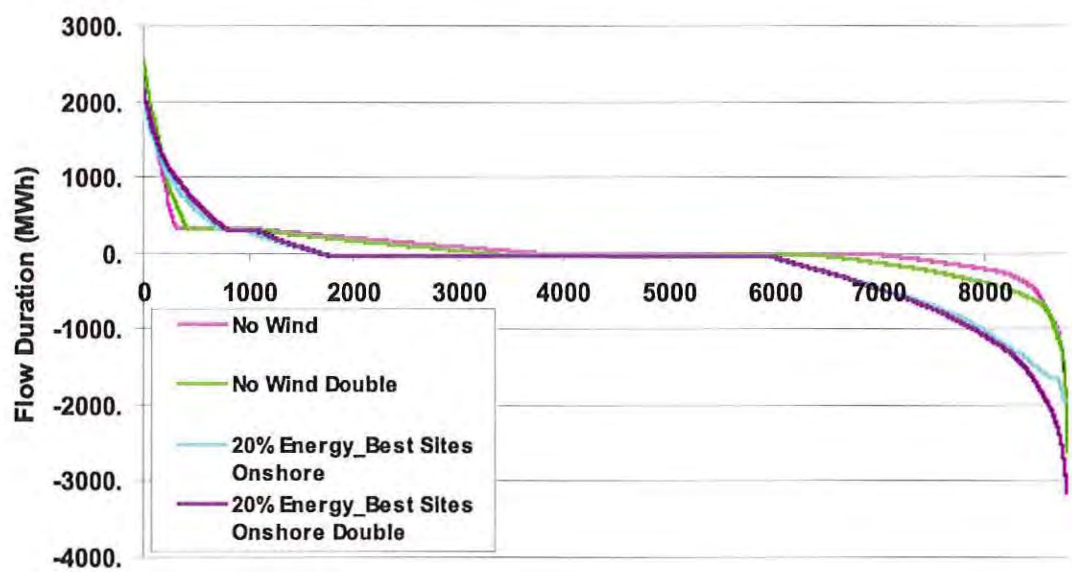


Figure 5–125 ISO-NE to NYISO Interface flow comparison

Figure 5–126 compares the generation duration of the HQ IMP generator for the four scenarios. The generation doubles in comparison of the scenarios.

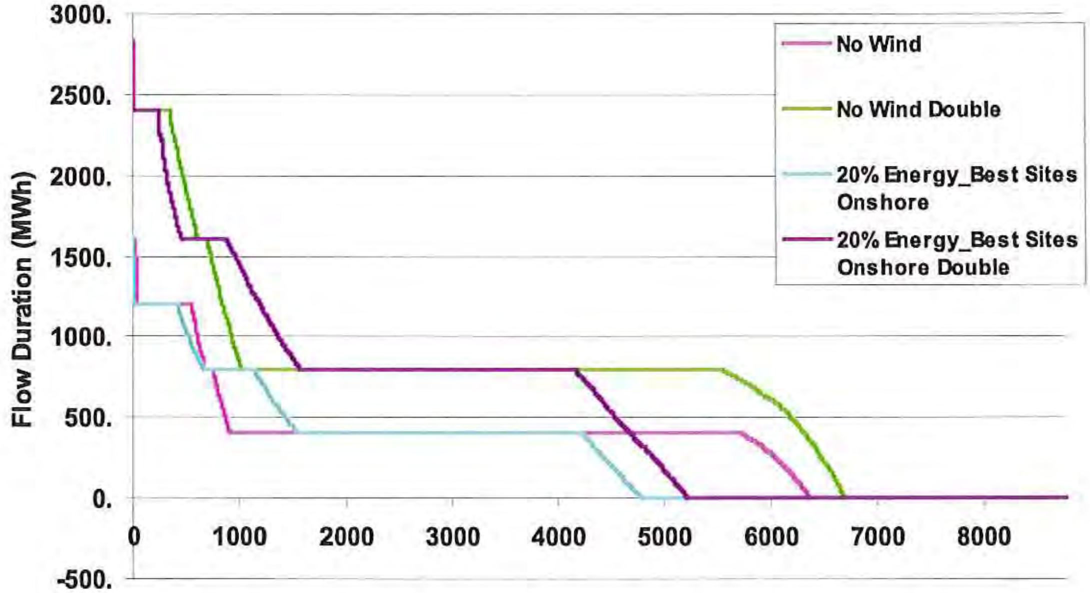


Figure 5–126 HQ Imports comparison

5.4 Operational Analysis Observations and Conclusions

From an hourly operational analysis viewpoint, integration of high levels of wind into the assumed ISO-NE system is feasible and produces energy values in the range of $50 – $54 per megawatt hour of wind energy generated; however, these results are based on numerous assumptions and hypothetical scenarios developed for modeling purposes only. The reduction in system-wide variable operating cost is essentially the marginal cost of energy, which should not be equated to a reduction in $/MWh for market clearing price (i.e. Locational Marginal Prices--LMPs). Low-priced wind resources could displace marginal resources, but that differential is not the same as reductions in LMPs.

As mentioned briefly in the introduction to the hourly analysis, the cost information is included only as a byproduct of the production cost analysis and that the study was not intended primarily to compare cost impacts for the various scenarios. These results are not intended to predict outcomes of the future electric system or market conditions and therefore should not be considered the primary basis for evaluating the different scenarios.

The assumed ISO-NE generation portfolio appears to be compatible with the studied penetrations of wind. Even up to 24% energy there were no significant operating issues observed, like running out of ramp/range up capability. There were few hours where the ramp/range went to 0, roughly 16 hours. Potentially, this can be addressed by curtailing wind. The generation displacement in ISO-NE is primarily combined cycles for all levels of penetration with some coal displacement occurring at higher penetrations. There were relatively small changes in PSH utilization across all levels of penetration. 20% wind penetration also had the following impacts:

- NOx - ~6,000 tons
- SOx - ~4,000 tons
- CO2 - ~12 million tons
- LMP – $5 to $11/MWh

For a given penetration of wind energy, differences in the locations of wind plants had very little effect on overall system performance. For example, the system operating costs and operational performance were roughly the same for all the 20% wind energy penetration scenarios analyzed. This is primarily because all the wind layout alternatives had somewhat similar wind profiles (since all of the higher penetration scenarios included the wind generation from the Full Queue), there was no significant congestion on the assumed transmission systems, and the assumed system had considerable flexibility, which made it robust in its capability of managing the uncertainty and variability of additional wind generation across and between the studied scenarios.

The individual metrics (e.g., prices, emissions) are useful in comparing scenarios, but should not be used in isolation to identify a preferred scenario or to predict actual future results.

There were very few hours when transmission congestion was an issue given assumed build-outs. Refinement of transmission build outs should be evaluated. The investment costs required for both the wind generation and transmission expansion were not considered in this analysis and will be an important factor in deciding which of the development paths suggested by the scenarios might be pursued. Some scenarios that showed the least transmission congestion also required the greatest investment in transmission, so congestion results should not be evaluated apart from transmission expansion requirements. Some scenarios that showed the greatest reductions in LMPs and generator emissions also used wind resources with low capacity factors, which would result in higher capital costs.

The impact on generation displacement and revenue reduction increased gradually with increasing wind penetration from the 2.5% through the 24% level. There appeared to be no major step change in the impact across this range.

The existing ISO-NE generation fleet is dominated by natural-gas-fired resources, which are potentially very flexible in terms of ramping and maneuvering. As shown in the upper left pie chart of Figure 5–127, natural gas resources provide about 50% of total annual electric energy in New England assuming no wind generation on the system. Wind generation would primarily displace natural-gas-fired generation since gas-fired generation is most often on the margin in the ISO-NE market. The pie charts show that as the penetration of wind generation increases, energy from natural gas resources is reduced while energy from other resources remains relatively constant. At a 24% wind energy penetration, natural gas resources would still be called upon to provide more than 25% of the total annual energy (lower right pie chart). In effect, a 24% wind energy scenario would likely result in wind and natural-gas-fired generation providing approximately the same amount of energy to the system, which would represent a major shift in the fuel mix for the region. It is unclear, given the large decrease in energy market revenues for natural-gas-fired resources, whether these units would be viable and therefore continue to be available to supply the system needs under this scenario. Revenue reduction for units not being displaced by wind energy is roughly 5%-10%, based on lower spot prices. For units that are being displaced, their revenue losses are even greater. This will likely lead to higher bids for capacity and may lead to higher bids for energy in order to maintain viability. The correct market signals must be in place in order to ensure that an adequate fleet of flexible resources is maintained. During peak hours, wind has a much lower than nameplate capacity value, even though up to 24% of energy is produced. Capacity value is discussed further in Chapter 6 of this report.

Incorporating the day-ahead wind forecast, even if it is imperfect, in the commitment decision was shown to make a significant impact at all levels of penetration. Analysis performed for the NEWIS indicates that these effects, and hence the case for implementation of a wind power forecast, grows as wind power penetrations increase.

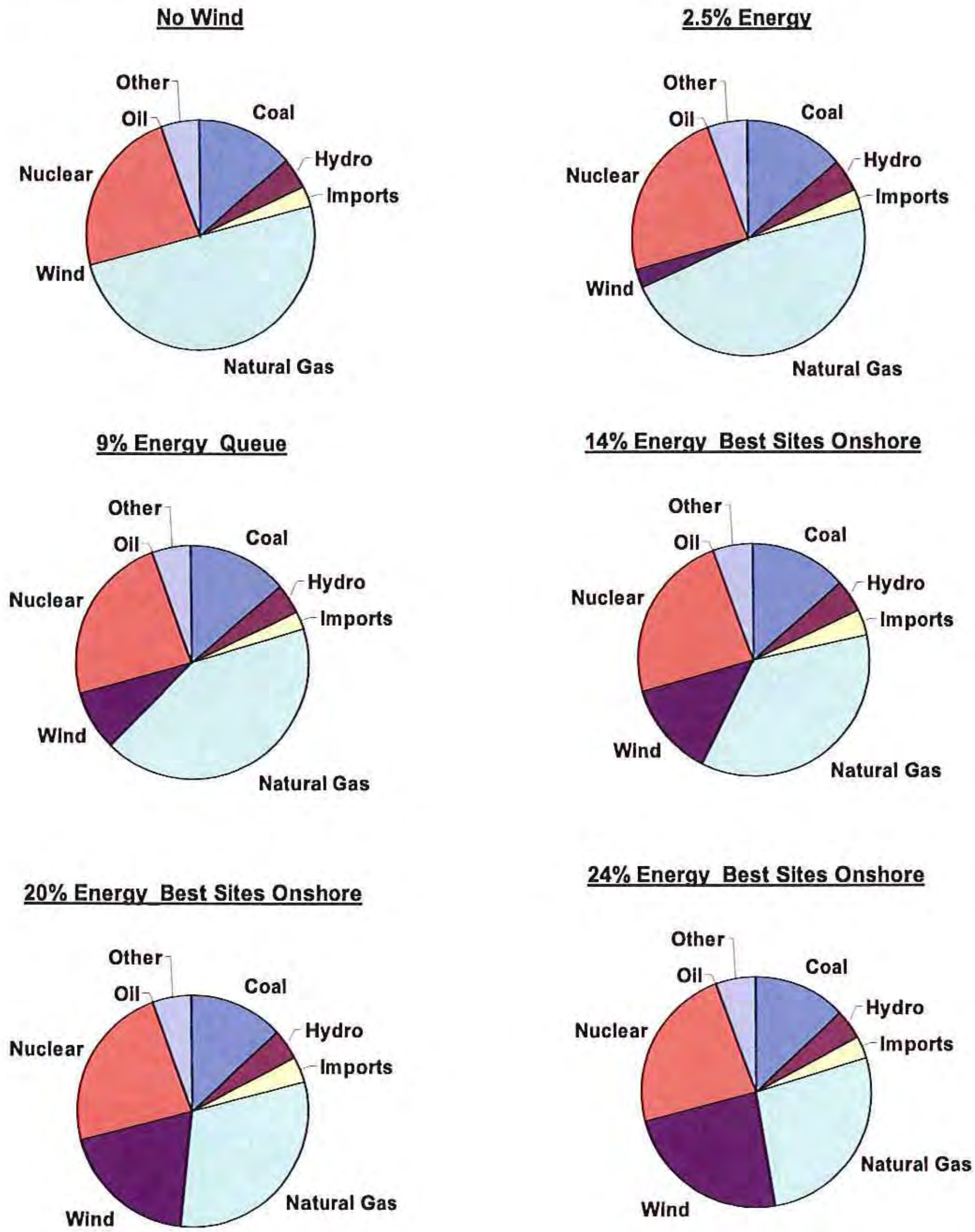


Figure 5–127 Annual Energy from ISO-NE Generation Fleet with Increasing Wind Energy Penetration.

6 Reliability Analysis

6.1 Introduction

A capacity value analysis was performed on the various wind generation scenarios being examined in New England. As with the operational analysis, multiple yearly wind profiles and load shapes were considered. The variation in results between the different annual patterns tends to be more pronounced in the capacity valuations as compared to the production simulations because the capacity value is much more a function of the wind performance for a few critical hours and days whereas the production value is a function of the generation throughout the year. This analysis considered variations in wind penetration, scenario layout and annual load shapes and wind profiles for all of the wind scenario aggregations. The capacity values were developed for each aggregation and no attempt was made to isolate the capacity value of wind resources by individual geographic area. It is also important to differentiate the "capacity value" from the similar sounding "capacity factor." The "capacity factor" is the annual energy production divided by the nameplate rating and the number of hours in the year. The capacity factors for the individual wind plants ranged from 27% to 47% based on their location. The "capacity value" is the expected amount of capacity that can be counted on to meet the installed capacity requirements needed to satisfy the system reliability criteria. As will be discussed later, the capacity values are often approximated by the average capacity factors during just the peak load hours. The capacity values for the various scenarios examined ranged from 20% to 36%.

Figure 6–1 shows a summary of how the results vary for a range of penetrations and annual patterns for the "Onshore" scenarios. (All of the scenarios at the 14% and 20% level will be examined in more detail later in this chapter.) The capacity values, in MW, are shown for each year of the analysis, along with the three-year average value. The red squares show the average capacity value as a percent of the installed nameplate capacity (right hand scale). The average capacity values decrease from 36% for the 2.5% penetration scenario down to 20% for the 20% penetration scenario.

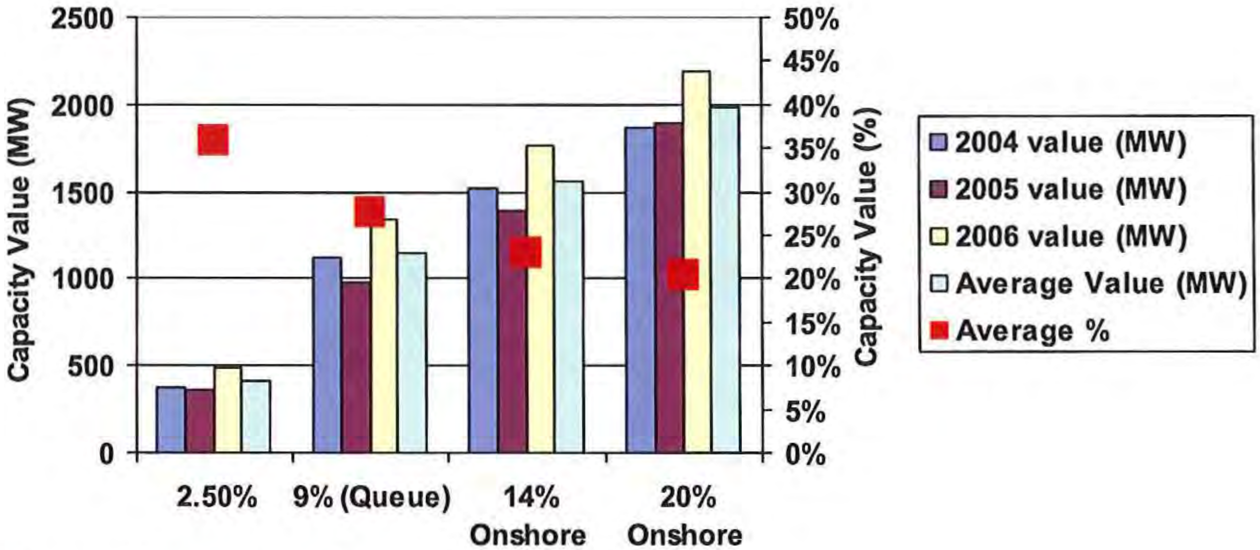


Figure 6–1 **Capacity value results**

The variability from year to year is typical of results seen in other wind integration studies (such as the New York and the Western Wind and Solar Integration Study discussed previously), as is the decrease in value with increasing penetrations. There are two primary causes for the decreasing values. The first is just saturation. The wind generation is not constant throughout the day or the year. Although there is variability in the generation, there are also patterns that emerge. As increasing amounts of generation are added with similar patterns, the original "peak hour" of the day has less and less impact on the daily risk while other hours, when the wind may not be as strong, become relatively more prominent in the calculation. Diversity of locations will help mitigate this effect, but similar diurnal patterns will exist. The second reason for the decrease is that the best sites were added first. The wind plants were ranked based on decreasing capacity factor. As higher penetrations were required, the capacity factors of the plants added decreased.

6.2 Methodology

A Loss of Load Expectation (LOLE) analysis was performed for the proposed 2020 ISO-NE system in order to determine the Effective Load Carrying Capability (ELCC) of the wind scenarios. The model used was the GE Multi-Area Reliability Simulation (MARS) program. Details of the model are discussed in Appendix D. The data used is the same as for the production simulation analysis with the following exceptions. In order to fully reflect the value within New England the neighboring systems were ignored. In addition, transmission constraints within New England were ignored. In this way, the capacity value of the wind generation will purely be a function of the hourly wind generation patterns, hourly load shapes and the size and characteristics of the balance of thermal and hydro generation within New England. For the 2004-based load and wind profiles, this resulted in an LOLE of 0.575 days/year. This is larger than the ISO-NE planning criteria of 0.1 days/year because, among other factors, the interconnection to neighboring systems and emergency operating procedures were ignored.

Increasing amounts of perfect capacity (that is, no planned or forced outages) were then added to the system to produce the results shown in Figure 6–2. As the capacity additions increased, the expected number of outages per year decreased. This then set the framework for the evaluation of the various wind generation scenarios.

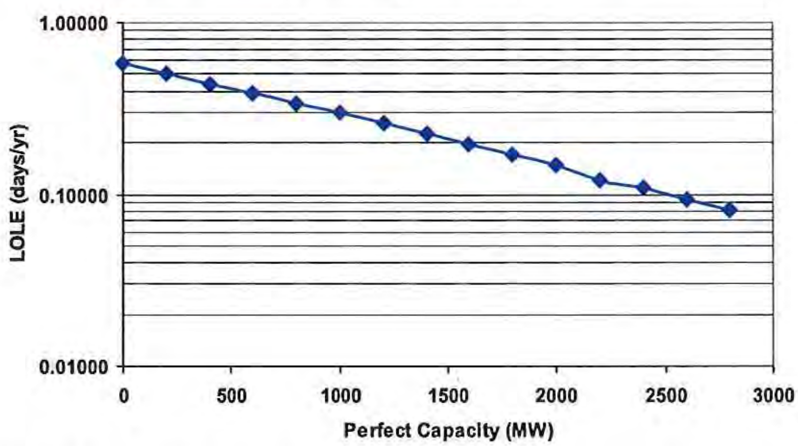


Figure 6–2 Perfect capacity impact for 2004 shapes

As the reliability index was then calculated for each of the scenarios, it could then be plotted on the curve shown in Figure 6–2 and the corresponding value in perfect capacity could be determined. These results are shown in Figure 6–3. The "Base Scenarios" refer to the "No Wind", "2.5%" and "9 %(Queue)" cases. For example, the 2.5% energy scenario reduced the risk to 0.451 days/year. Interpolating from the curve shows that it would require 370 MW of perfect capacity to achieve the same amount of risk improvement. Therefore, the 2.5% energy scenario has a capacity value of 370 MW. Since this scenario included 1140 MW of nameplate wind capacity then the capacity value was 33% (= 370/1140). Each of the other scenarios was then evaluated and the reliability results are shown in Figure 6–3. Note that the first point off the y-axis corresponds to the 2.5% energy scenario.

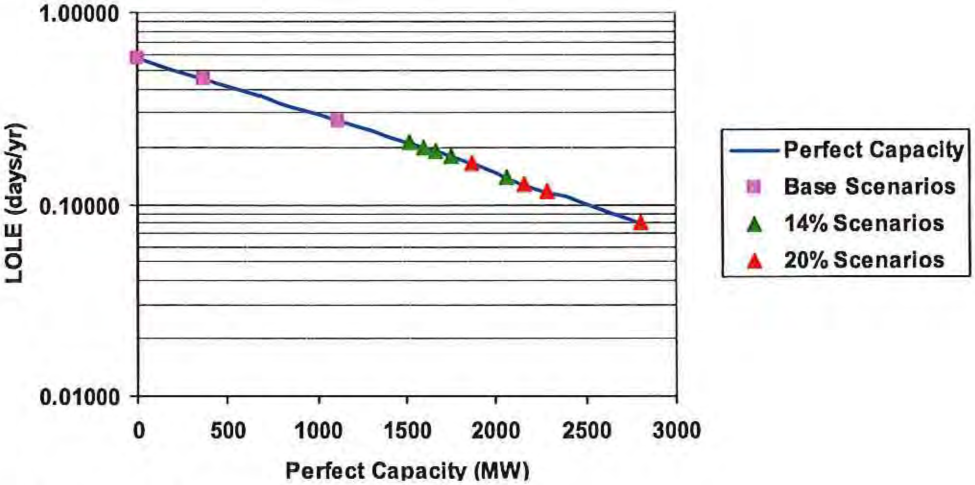


Figure 6–3 LOLE analysis with 2004 based profiles

This analysis was then repeated for each of the annual shapes. The base "perfect capacity" curves are shown in Figure 6–4. Although all three load shapes were adjusted to the same annual peak the starting "no wind" reliability was different due to the underlying shapes. This will be discussed more later in the chapter.

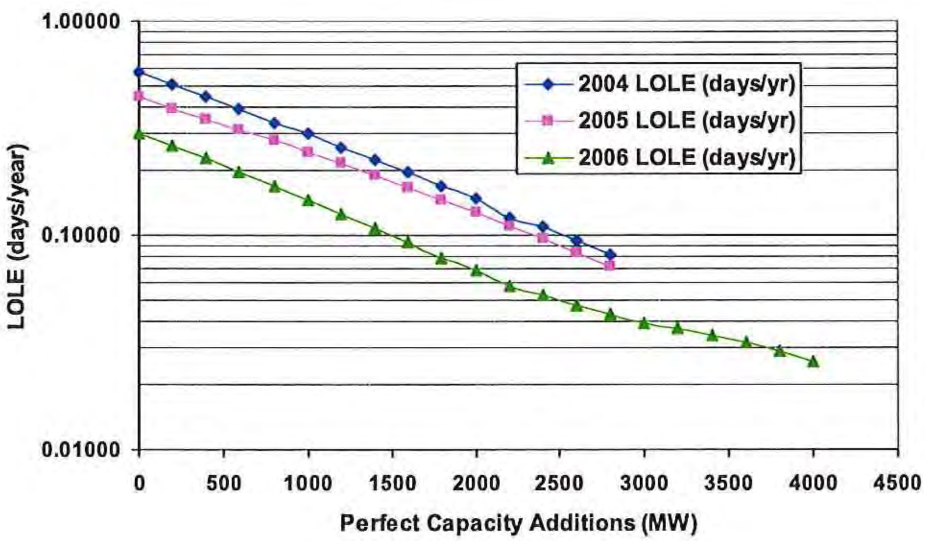


Figure 6–4 Perfect capacity impacts for all three years

6.3 Capacity Value Variation by Scenario

There was only a single scenario layout for the 2.5% and 9% energy cases. However, the 14% energy and 20% energy penetration scenarios considered several different layout alternatives, as has been discussed previously. Because the annual capacity factor varied between the scenario layout alternatives the amount of nameplate capacity also varied. In order to more easily compare the results the capacity values are shown as a percent of the installed capacity rather than as MW values. Figure 6–5 shows the annual and average results for the various scenarios with 14% energy. (Note: the "Best Sites" scenario is also referred to as the "Balance" scenario.) The output from the offshore sites tended to be more aligned with the load profile, and therefore had better capacity values. The text line under the chart shows the percent of offshore nameplate capacity in each scenario. The scenarios were ranked in order of increasing offshore percentage to highlight the impact. Although all scenarios delivered 14% wind energy the capacity values ranged from roughly 20% to 40%.

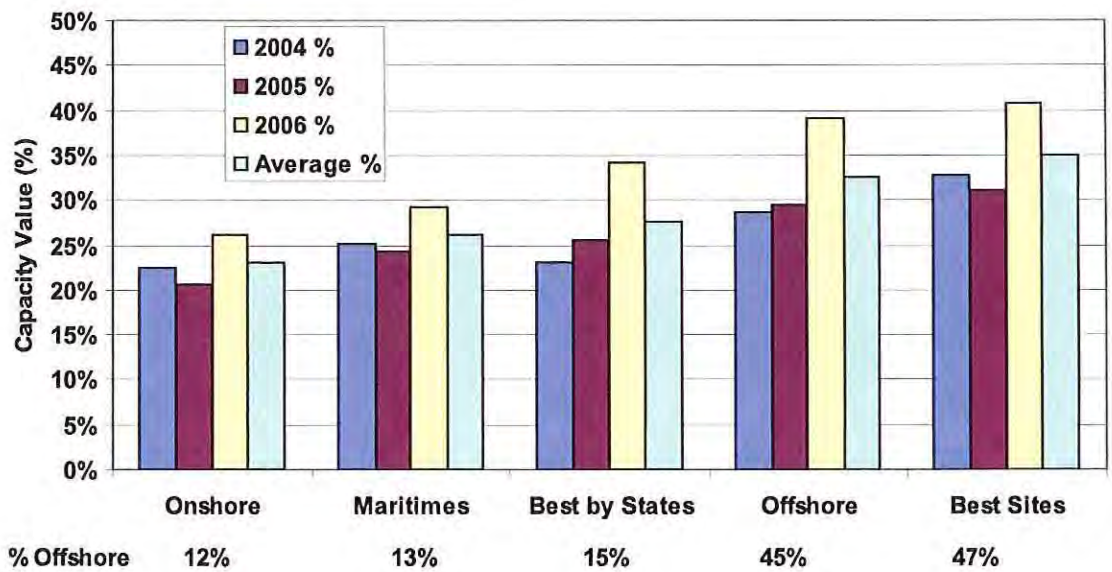


Figure 6–5 **Capacity value (% of nameplate) for 14% scenarios**

Figure 6–6 shows similar results for the 20% energy scenarios. Although the Maritime scenario only had 9% of the energy from offshore locations the wind profiles were more like the offshore patterns due to scenario layout largely along the coastal area. It can be seen that the capacity value varies for the different scenario layouts but also from year to year for the same scenario. Figure 6–7 combines the 14% and 20% results for easy comparison.

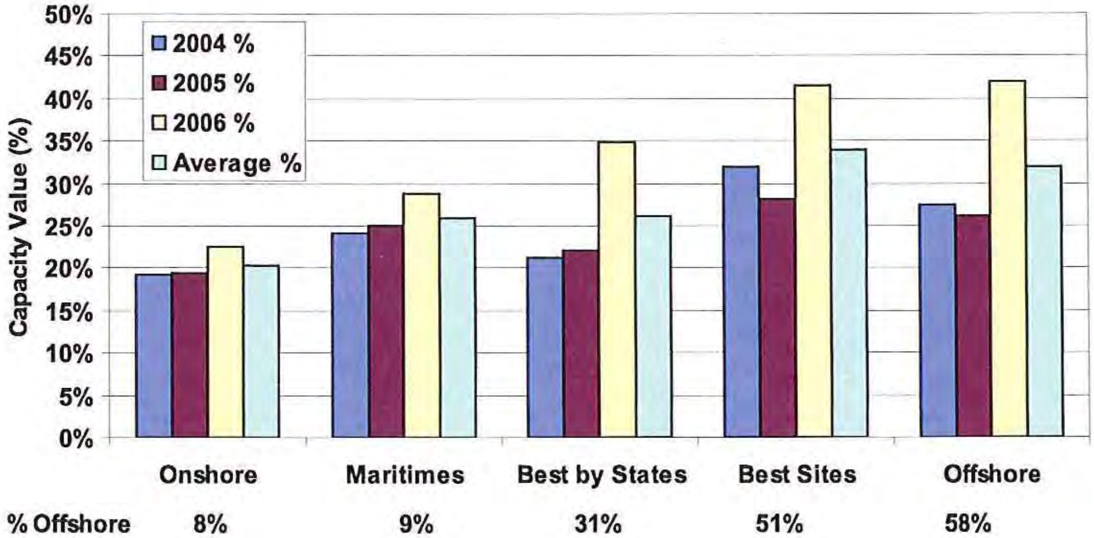


Figure 6–6 Capacity value (% of nameplate) for 20% scenarios

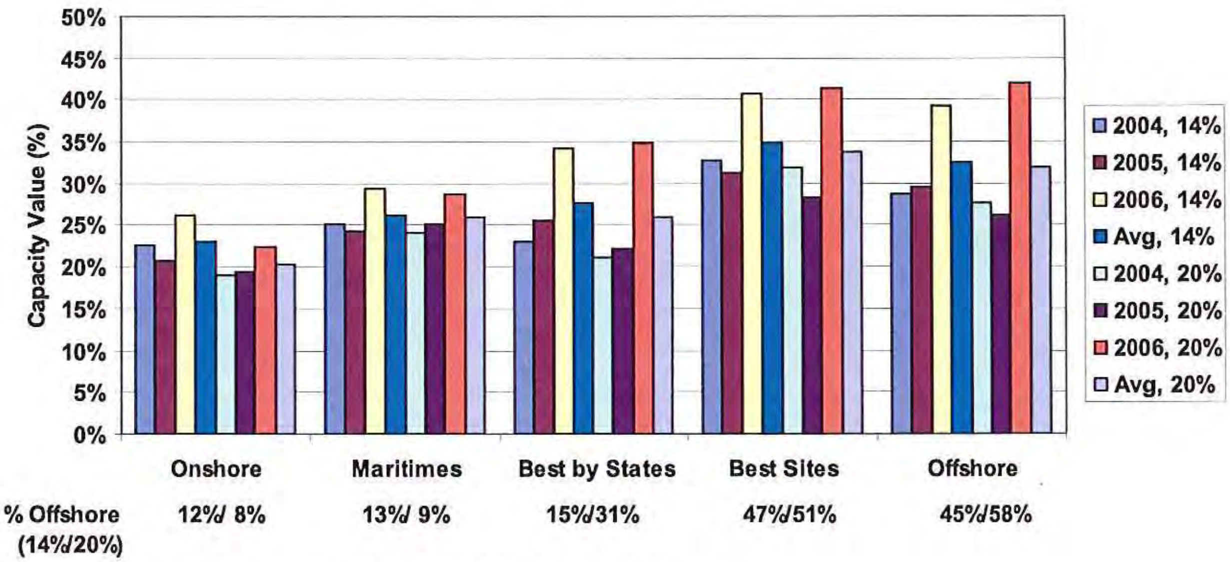


Figure 6–7 Capacity value (% of nameplate) for 14% and 20% scenarios

6.4 Capacity Value Variation by Shape Year

The capacity value of variable generation is a function of the alignment of the load and wind shapes. While there is a definite seasonal and diurnal shape to the wind generation, it is not clear how tightly it is correlated to loads, therefore it may be useful to permute the available wind and load profiles to see how much the coincidence of the load and wind contributed to the overall result. Figure 6–8 matches each of the load shapes to each of the wind profiles. The 2006 wind profile gave similar results for all three load shapes but the other two wind profiles produced capacity values that varied by almost a factor of two for different load shapes. This would indicate that the 2006 wind profile tended to have relatively consistent wind throughout the peak load periods while the other two wind profiles managed to match the peak load days in some years but not in others.

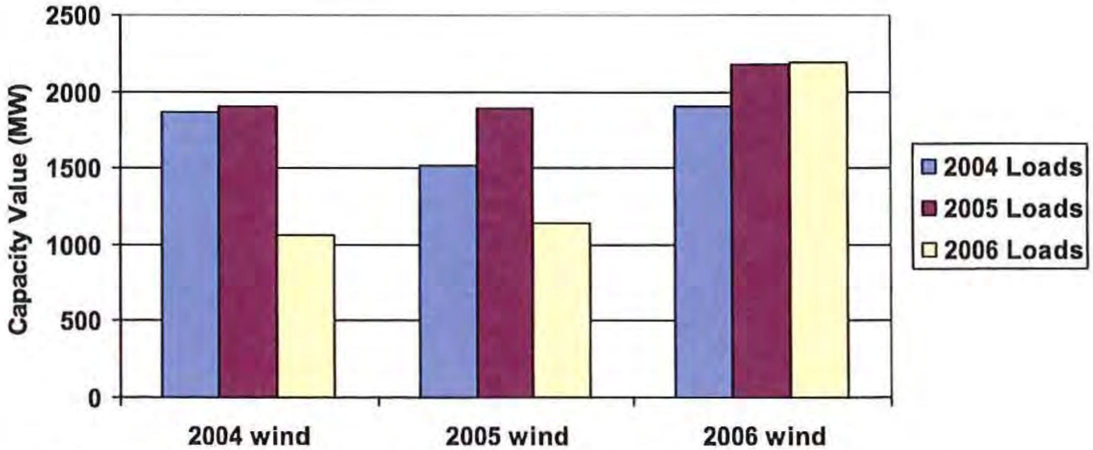


Figure 6–8 Impact of load and wind shapes - capacity values for 20% onshore scenario

Although the system risk comes from more than just the peak day of the year it is often useful to see what is happening on that day. Figure 6–9 shows the load shapes for the three years and the generation from the 20% Onshore and Offshore scenarios. The load profiles are quite similar but the wind profiles are significantly different. Some of the key statistics from this figure and the peak load hour are listed in Table 6–1. The aggregate scenario wind generation during the peak load hour ranges from 10% of nameplate for the 2004 Onshore case to 65% for the 2006 Offshore scenario. Overall, the Onshore scenarios average 23% availability at the peak hour and the Offshore scenarios average 54%. This is typical of their performance, even though the average annual capacity factors are not that different: 34% for Onshore and 40% for Offshore.

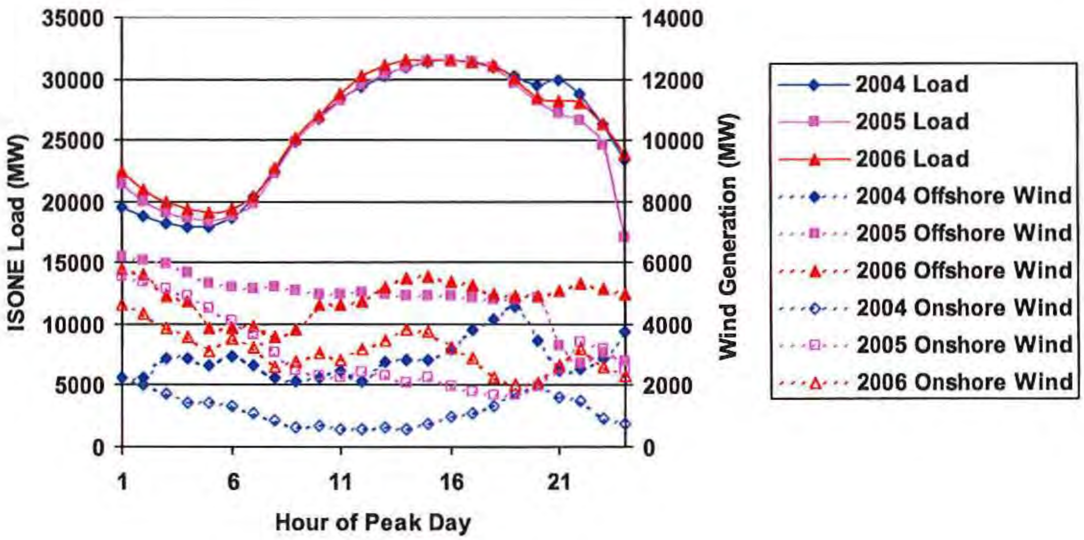


Figure 6–9 Load and wind on peak day

Table 6–1 Wind generation at the peak hour

	2004 Offshore Wind	2005 Offshore Wind	2006 Offshore Wind	2004 Onshore Wind	2005 Onshore Wind	2006 Onshore Wind
capacity	8360	8360	8360	9770	9770	9770
daily max	4578	6182	5810	2272	5533	4645
%	55%	74%	69%	23%	57%	48%
gen @ peak	3157	4896	5468	988	1940	3810
%	38%	59%	65%	10%	20%	39%

Figure 6–10 shows the average daily profile for the three years for these two scenarios. Even though the Onshore scenarios have 1410 MW more installed capacity the Offshore scenarios average more generation during the late afternoon/early evening period when the peak loads occur.

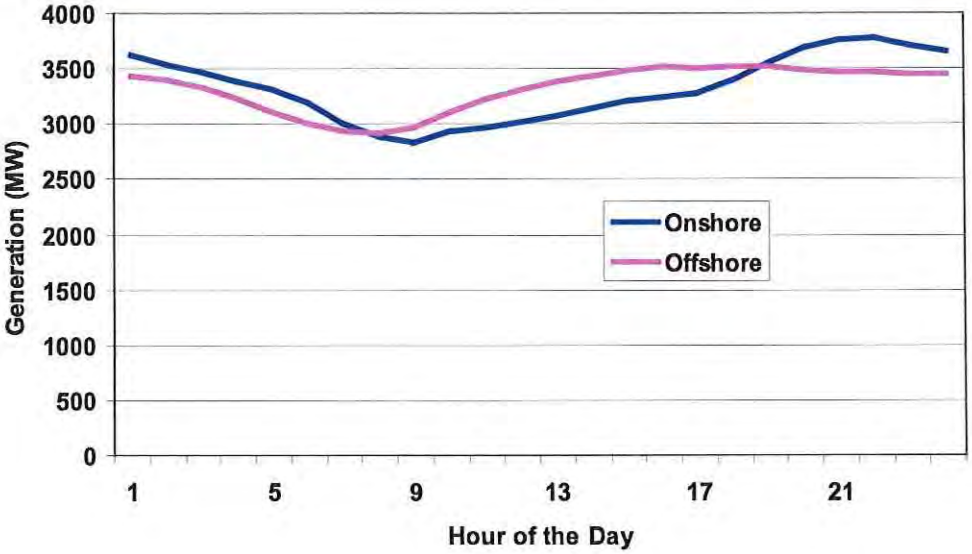


Figure 6–10 Average daily profiles, 20% energy scenarios.

Figure 6–11 shows the annual wind generation duration curves for the 20% scenarios. The energy under each curve is roughly the same but the Onshore cases tend to drop more rapidly from their peak values than the Offshore cases do.

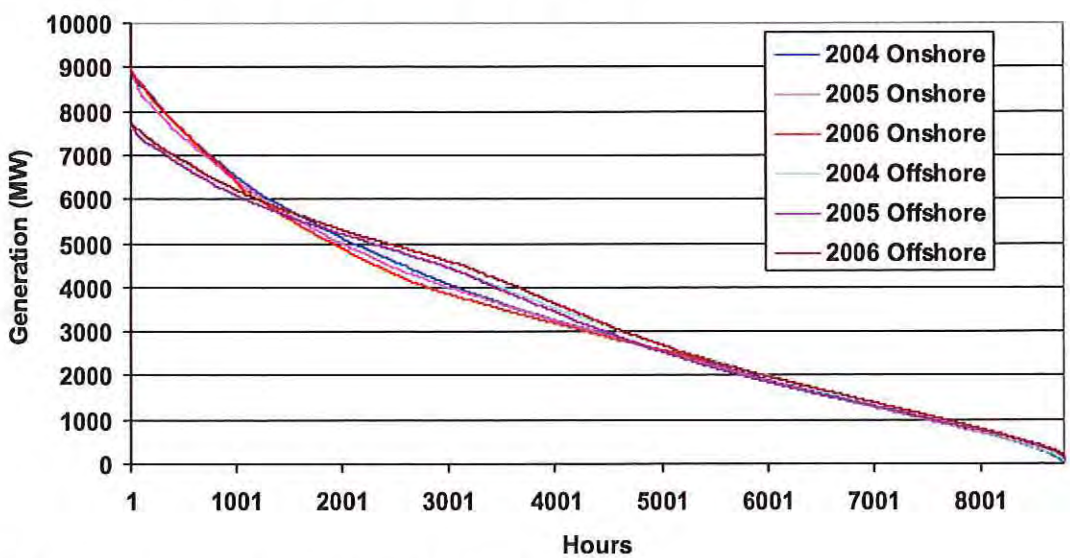


Figure 6–11 Generation duration curves for 20% penetration

Figure 6–12 shows the monthly capacity factors for the cases. The Offshore cases have significantly more energy in the peak month of July, particularly in 2006.

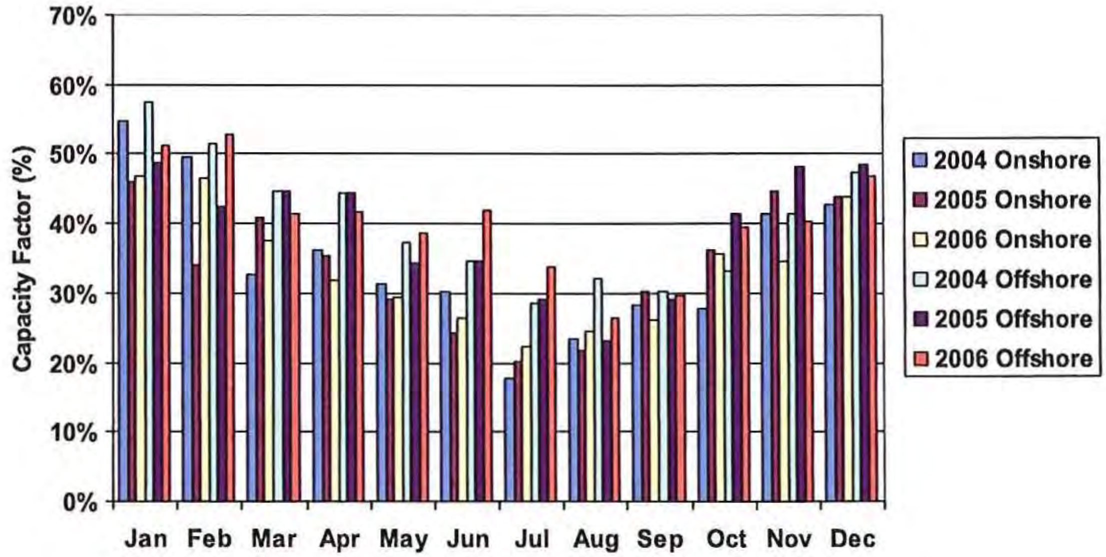


Figure 6–12 Monthly wind capacity factors for 20% scenarios

The load shapes are also a critical factor in the capacity value calculations. Figure 6–13 shows the profiles of the daily peak loads for the three load shape years.

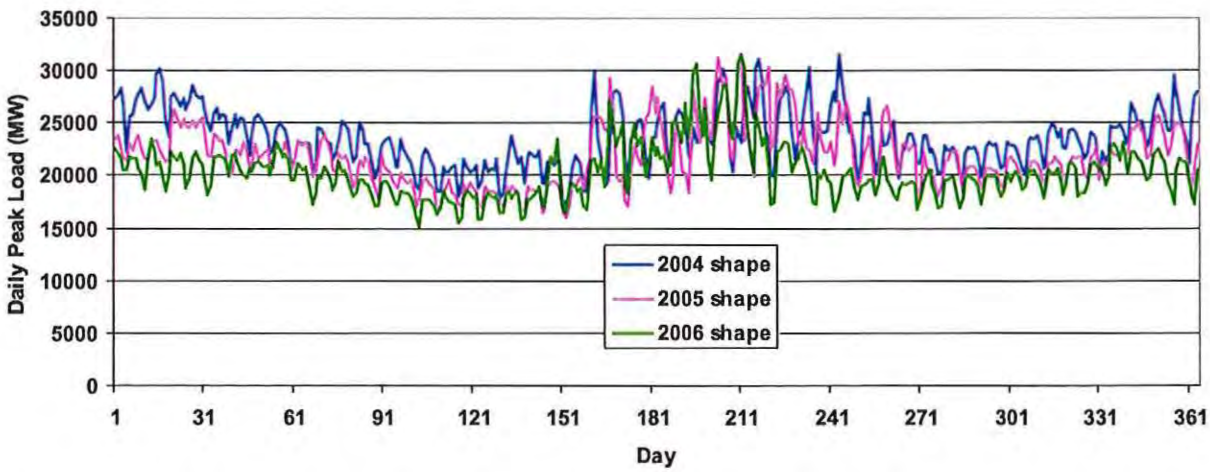


Figure 6–13 Chronological daily peak loads