HATCH™

Final Report

Nova Scotia Wind Integration Study

For

Nova Scotia Department of Energy

2008

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Final Report

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Wind Integration Study for Department of Energy, Government of Nova Scotia

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ES Executive Summary

The Nova Scotia Department of Energy (DOE) commissioned Hatch Ltd. (Hatch) to conduct an independent study to identify and assess the impacts of integrating large scale wind power generation into Nova Scotia's electric power system.

The report's findings will assist Nova Scotia's efforts towards building its renewable energy supply, both to secure a local energy resource and to protect the environment.

Currently, Nova Scotia's electric power generation is approximately 90% fossil-fuel based and accounts for more than 40 per cent of all provincial greenhouse gas emissions (NRCan, 2006). As of 2007, Nova Scotia Power Inc. (NSPI) operated approximately 2,300 megawatts (MW) of generation capacity which is a mix of fossil fuels, hydroelectric, tidal, wind and independent power producers.

In 2007, Nova Scotia enacted the *Environmental Goals and Sustainable Prosperity Act* (EG&SPA). The Act sets a provincial goal to reduce greenhouse gas emissions to at least 10 percent below 1990 levels by the year 2020.

Also in 2007, Nova Scotia created a Renewable Energy Standard (RES). The RES requires that by 2013, 10% of the province's electricity requirement must be supplied by new renewable energy sources post 2001 (5% by 2010 and an additional 5% by 2013). Hatch estimates the 2013 RES requirement will bring the total provincial renewable supply to approximately 22% (581 MW). DOE expects most of this supply to be met with commercial-scale wind energy projects, and estimates the number of utility wind turbines in the province may grow from the current 41 to over 300.

Wind energy offers many advantages: emission-free, renewable, domestic, and cost-competitive. Wind energy also has many challenges: it depends greatly on average wind speeds, is subject to frequent and wide variations in output, and therefore cannot be relied on to deliver electricity at the exact time and in the exact amounts required by the electric system. Nova Scotia's electric system has limited interconnection with other jurisdictions, and limited quick response generation, which makes it difficult to respond to varying wind generation.

This report covers three time periods:

- Present to 2010 (potential impacts of 2010 RES requirement, assuming a total of 311 MW of wind power capacity)
- 2010 to 2013 (potential impacts of 2013 RES requirement, assuming a total of 581 MW of wind power capacity)
- 2013 to 2020 (potential impacts beyond RES requirements, assuming totals of 781 MW and 981 MW of wind power capacity)

The Department of Energy organized an Advisory Committee to assist in monitoring and reviewing the study progress, and to provide advice on the methodology, assumptions, data sources and timeframe. The organizations represented on this Advisory Committee are:

1. Nova Scotia Department of Energy
2. Nova Scotia Power Inc.
3. Nova Scotia Power System Operator
4. Nova Scotia Utility and Review Board
5. Consumer Advocate
6. Municipal Electric Utilities of Nova Scotia Cooperative
7. Canadian Wind Energy Association.

KEY FINDINGS:

2010 RES (assuming a total of 311 MW of wind power capacity):

- The 2010 RES target for renewable supply can be met
- By 2010, electricity production from post 2001 renewables is estimated to reach 7% -- total production from renewables at 16%
- By 2010, CO_2 emissions by electricity production system is estimated to decrease by 550 kilotonnes per year or by 5% (equivalent to taking 100,000 cars off road) †

2013 RES (assuming a total of 581 MW of wind power capacity):

- The 2013 RES target for renewable supply can be met, but more detailed impact studies are required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure.
- By 2013, electricity production from post 2001 renewables would reach 13% -- total production from renewables at 22%.
- By 2013, emissions would decrease by a projected 1,300 kilotonnes per year or by 12% (equivalent to taking 232,000 cars off road) †
- By 2013, the system operator will need to use a variety of management techniques to maintain system stability and reliability. These techniques may include: imports of electricity; starting and stopping slow-response thermal units (some of these units may take days to shut down and re-start); management of interruptible load; and curtailment of wind generation.
- By 2013, the number of starts and stops of the large thermal units will increase. All components of the delivery system will experience greater load variations. The system may be called on to operate in ways it was not designed for and the total cost impacts are not well understood at this time.
- Up to 2013, given study assumptions and scope, increases in renewable production and decreases in CO_2 emissions may be achievable with little impact on production costs when the assumed level of carbon costs are taken into account (this is not definitive; further study and experience is needed to verify).

Beyond 2013 RES (assuming 781 MW and 981 MW of wind power capacity):

- Future study will be needed to fully understand the cost and stability issues of increasing wind supply to 781 MW and 981 MW levels, after we gain more real world operational experience with increasing amounts of wind supply.
- The number of starts and stops of the large thermal units will increase significantly. All components of the delivery system will experience greater load variations. The system may be called on to operate in ways it was not designed for and the total cost impacts are not well understood at this time.
- There could be significant infrastructure costs involved ($100s of millions) to upgrade Nova Scotia's transmission system to integrate these levels of wind. System costs will be impacted (such as capital, fuel, operation and maintenance costs) as electricity production from coal, petcoke and heavy oil is reduced and replaced by wind, light fuel oil and natural gas. Costs will also depend greatly on how the system evolves in the next several years, particularly Nova Scotia's interconnections to neighbouring regions.
- These costs may be offset by rising fossil fuel prices, possible carbon levies, and other factors, but these are unclear at this point.

NEXT STEPS

By 2013, the RES will push Nova Scotia to significant levels of wind supply. Given Nova Scotia's current circumstance – limited regional interconnection and limited fast-ramping generating capability – the 2013 RES deadline to increase the amount of renewable power generation integrated into the electric system is ambitious, but realistic. Nova Scotia certainly has the wind resource to go beyond the RES, but many issues require further examination. For example:

- More detailed studies of the high voltage transmission system (referred to as dynamic stability studies) are needed; these studies should be done in advance of the estimated 520 MW of new wind power capacity for 2013 to identify any possible transmission upgrades necessary.
- The experience gained as more wind is added can be used to better manage the generation system, using:
  - actual production patterns of the operating wind power plants
  - a wind power forecasting pilot project
  - additional information on the time patterns of wind power generation
  - technical/economic studies to investigate viability of investment in NSPI's major thermal power units to allow better adaptation to more frequent stops/starts and output fluctuation
- Other possible ways to increase wind power integration include:
  - actions that allow participation in electricity markets outside Nova Scotia.
  - contracts that allow curtailment of wind power output when the system cannot effectively absorb full production
  - upgrading Nova Scotia's high voltage transmission system to increase capacity, particularly in areas with the best wind regimes
  - developing and installing cost effective storage technology
  - investments in quick response generation

SUMMARY TABLE

Target	MW*	Comments
2008	61	Current status System stability not an issue Wind is cost-effective** Total renewable supply: 12% (total wind: 2%)
2010	311	RES target can be met Wind is cost-effective** 550 kilotonnes (KT) or 5% GHG reduction/year Total renewable energy supply: 16% (total wind: 7%)
2013	581	System stability may be an issue and requires detailed study 1300 KT or 12% GHG reduction/year Some system upgrade required Total renewable energy supply: 22% (total wind: 13%)
2020	781 and 981	781: total renewable energy supply: 27% (total wind: 18%) 1880 KT or 18% GHG reduction/year 981: total renewable energy supply: 33% (total wind: 24%) 2650 KT or 25% GHG reduction/year More detailed system impact studies required (many variables involved) Costs could be significant Some factors influencing stability and costs will include: - location of new projects - system upgrades 2008 to 2013 - regional interconnections (including NB, NFLD, and USA) - back-up supply issues - technological innovation

*Assuming base-line of 61 megawatts with an additional 70 megawatts of supply to wholesale market by 2013.
** Assuming values of $15.06, $22.40 and $38.76 per estimated tonne of CO_2 emissions for the years 2010, 2013 and 2020 respectively. Prices of 8.5¢ and 8¢ (plus an allowance for escalation) per kilowatt/hour delivered were assumed for wind plants in 2010 and 2013 respectively.
† For average vehicle emissions, the US Environmental Protection Agency (EPA) recommends using an estimate of 5.5 metric tonnes/year of greenhouse gas.

1. Introduction

1.1 Introduction

This report was prepared by Hatch Ltd. (Hatch) for the Nova Scotia Department of Energy (NSDOE) to assist it in identifying and assessing the impacts of integrating large scale wind generation into Nova Scotia's electric power system.

Information is provided in this introductory section on the Terms of Reference and contract, the Advisory Committee, the process and timeframe for the project and an outline of the information provided in this report.

1.2 Terms of Reference and Contract

On June 29, 2007, Hatch submitted a proposal to Nova Scotia Procurement Services for the Nova Scotia Wind Integration Study. This proposal was in response to Request for Proposal 60132178 dated June 15, 2007 which included the detailed Terms of Reference for the assignment. These Terms of Reference dated June 8, 2007 are included in Appendix A.

Following evaluation of its proposal, Hatch was requested to present its proposal to NSDOE and members of an Advisory Committee that it had formed for this study. Following this presentation, Hatch was provided with a draft contract for the assignment. The contract was completed and signed by both parties prior to the end of July.

1.3 Advisory Committee

At the outset of the project NSDOE appointed an Advisory Committee with the mandate to assist it in monitoring and reviewing the progress of the work and to provide advice on the methodology, assumptions, data sources and timeframe for the work. The organizations represented on this Advisory Committee are as follows:

(1) Nova Scotia Department of Energy

(2) Nova Scotia Power Inc.

(3) Nova Scotia Power System Operator

(4) Nova Scotia Utility and Review Board

(5) Consumer Advocate

(6) Municipal Electric Utilities of Nova Scotia Cooperative

(7) Canadian Wind Energy Association.

During the course of the study Hatch has given regular presentations to the Advisory Committee to update the members on the progress of the work. On each of these occasions the Advisory Committee has provided valuable feedback to Hatch.

1.4 Process of the Work

The following are some of the key activities carried out during the project:

(1) Signature of contract – July 26, 2007

(2) Data collection plan/request submitted – July 30, 2007

(3) Non Disclosure Agreement signed – August 1, 2007

(4) Data collection visit – August 1 & 2, 2007

(5) Requests to wind developers – August 8 & 9, 2007

(6) Interim Reports submitted – September 5 and October 29, 2007

(7) Updates to the Advisory Committee – August 2 & 30, September 21, October 19, November 16, December 17, 2007, February 8 and March 20, 2008

(8) Webex with NSPI – September 12, October 5, November 7 & 9, December 14, 2007

(9) Workshop with NSPI – February 4-6, 2008

(10) Draft Final Report submitted – March 10, 2008.

The RFP for the study indicated a requirement for the successful consultant to submit its final report by November 30, 2007 and Hatch indicated in its proposal that it would make its best efforts to achieve that date. However, as the work progressed it was realized that a longer period would be required to collect the necessary data, carry out the analysis using this data and draw conclusions on the impacts of greater levels of wind power integration. It was also recognized that, due to the importance of the study and how its results would be used, it was preferable to carry out the analysis more carefully rather than more quickly. Thus, NSDOE, with the support of the Advisory Committee, agreed to a series of extensions to the study schedule. The Draft Final Report was submitted in early March and this Final Report is being submitted at the end of April, 2008.

1.5 Data Collection

In order to carry out the study, Hatch required a significant amount of data on a) the Nova Scotia Power system and b) the wind resources in Nova Scotia. At the start of the study, a detailed list of the data and information requirements was prepared and submitted. As much of the required data is confidential, non disclosure agreements were entered into before data collection began. While confidential data was used in carrying out the analyses, this report does not divulge any data that is considered to be confidential by its owners.

1.6 Outline of This Report

The report begins with an Executive Summary. Following this introductory section, Section 2 provides an overview of Nova Scotia's electric power system and Section 3 summarizes the major assumptions used in the study. Section 4 describes the collection of the wind resource data and the use of this data to develop wind power generation data for each of several zones in the Province. Section 5 describes the results of the modeling carried out to simulate the dispatch of the system under the assumed wind capacity installation cases. Section 6 describes the transmission system analysis that was carried out. Section 7 describes the analysis of the impacts of varying levels of increased wind generation capacity and the potential ways to mitigate the undesirable impacts. Section 8 presents the conclusions and recommendations of the study. Appendix A provides the Terms of Reference for the study.

2. Overview of Nova Scotia's Electric Power Sector

2.1 Introduction

Nova Scotia's power sector is dominated by Nova Scotia Power Inc. (NSPI), a subsidiary of Emera Inc. NSPI is a vertically integrated electric utility, regulated by the Nova Scotia Utility and Review Board (UARB). The company generates electricity for the province using coal, petcoke, oil, hydro, natural gas and wind and it transmits and delivers electricity to residential, commercial, industrial customers and municipal utilities across the province. The company also purchases electricity from independent power producers (IPPs) through long-term power purchase agreements (PPAs) and out-of-province day ahead (forward) markets to meet its customers' needs, and sells surplus electricity to out-of-province forward markets.

2.2 Organizations Involved

The main organizations involved in the Nova Scotia electric power sector include the Department of Energy of the Nova Scotia government, UARB, NSPI, municipal utilities and IPPs.

The Energy Department's mission is to deliver maximum economic, social, and environmental benefits from the energy sector by creating partnerships with governments, industry, other provincial departments and local communities to develop, establish and manage the province's energy policies.

The UARB is an independent quasi-judicial body which has both regulatory and adjudicative jurisdiction flowing from the Utility and Review Board Act. It reports to the Legislature through the Minister of Finance.

NSPI generates/purchases, transmits and delivers electricity to residential, commercial and industrial customers and municipal utilities across the province and it also sells electricity in out-of-province markets.

The municipal utilities are distribution companies that purchase (and potentially generate) and sell electricity to the customers located within their boundaries.

The IPPs generate electricity and sell it to NSPI or municipal utilities through long-term power purchase agreements.

2.3 Existing Generation System

The Natural Resources Canada report titled "Canada's Energy Outlook: Reference Case 2006" indicates that the province of Nova Scotia produced a total of 12,600 GWh of electric energy in 2004 of which approximately 11,500 GWh or some 91.3% was produced by fossil fuel based generating facilities. This report also indicates that in 2004, the province emitted a total of 23.1 million tonnes of CO_2 equivalent of which approximately 9.3 million tonnes or some 40.3% was from electric power generation.

In 2006, NSPI supplied some 97% of the electrical energy used by Nova Scotians. Approximately 85% of the company's power production came from five thermal generating plants located throughout the province (Lingan, Point Aconi, Point Tupper, Trenton and Tufts Cove). Coal and petcoke are the primary sources of energy in these stations, with the exception of Tufts Cove which uses oil and natural gas. The remaining 12% of the electrical energy was generated by NSPI's 33 hydroelectric plants, one tidal power plant, four combustion turbine plants, two wind turbines and by independent power producers located across Nova Scotia with power plants using wind, water, biomass and biogas as their energy sources.

As of June 30, 2007, NSPI had a total of some 2,314 MW net firm generating capacity at the time of system peak, of which 1,893 MW was from thermal generation and the remaining 421 MW was from hydroelectric, tidal, wind and IPPs. Of the 1,893 MW of thermal generation, coal/petcoke fired generating units contributed 1,252 MW, oil/natural gas fired steam-driven turbines contributed 321 MW, gas turbines contributed 98 MW and diesel units contributed 222 MW. Table 2-1 lists all thermal generating units, their fuels, net firm capacity and other technical information.

NSPI has a total of some 377 MW net firm generating capacity from both hydroelectric and tidal generation. Wreck Cove station is the largest hydroelectric generating station with two units, each with a capacity of 115 MW. However, the maximum output of the plant is limited to 210 MW due to operational constraints. Including installations owned by IPPs, there is a total of some 60 MW of wind power generation, which is equivalent to some 19 MW firm capacity with the presumption of 32% firm capacity contribution. Table 2-2 lists all hydro and tidal generating stations as well as their firm capacity and expected annual energy output. Table 2-3 lists all wind plants, their rated capacity, ownership and other information.

The locations of major generating stations and the Nova Scotia electric grid are presented in Figure 2-1.

2.4 Existing Transmission System

The Nova Scotia Power transmission network consists of 69 kV, 138 kV, 230 kV and 345 kV lines. The 345 kV and 230 kV transmission lines form the backbone of the provincial transmission system. A single 266 km long 345 kV transmission line runs from Woodbine in the Sydney area to Onslow in the Truro area. From Onslow, a single 106 km 345 kV line extends to Lakeside in the Halifax area. In parallel with the 345 kV line, two 240 km long 230 kV transmission circuits run from Lingan in the Sydney are to Port Hastings in the Port Hawkesbury area and from Port Hastings, three 230 kV circuits are connected to Brushy Hill in the Halifax area via Onslow. In addition, two 230 kV circuits connect Brushy Hill to Bridgewater.

Nova Scotia is interconnected with New Brunswick through one 345 kV and two 138 kV transmission lines. A single circuit 160 km long 345 kV transmission line runs from Onslow to Salisbury in New Brunswick via Meramcook 345 kV substation. Two single circuit 138 kV lines from Springfield and Maccan are also connected to Meramcook in New Brunswick. As the New Brunswick system is interconnected with the province of Quebec and the State of Maine in USA, Nova Scotia is integrated into the NPCC power system.

The total winter peak load in 2007 was forecast at 2,257 MW. Halifax is the largest load center which accounts for over 30% (approximately 680 MW) of the total load in winter peak conditions. There are two other large substation loads of 360 MW each in the Nova Scotia system. One is in the east of the province and the other is in the west.

2.5 Renewable Energy Standards

In 2007, Nova Scotia enacted the Environmental Goals and Sustainable Prosperity Act (EG&SPA). The Act sets a provincial goal to reduce greenhouse gas emissions to at least 10 percent below the levels that were emitted in the year 1990 by the year 2020.

The Nova Scotia 2007 Renewable Energy Standard (RES) Regulations stipulate the renewable energy standard 2010 and renewable energy standard 2013. These regulations are reproduced in the following two subsections as excerpted from Schedule “A”, Regulations Respecting Renewable Energy Standards made under Section 5 of Chapter 25 of the Acts of 2004, the Electricity Act.

The Nova Scotia RES requires that, by 2010, 5% of the total Nova Scotia electricity requirement be supplied by post 2001 renewable energy sources, rising to 10% by 2013. The term of post 2001 source means an electricity generator constructed on or after December 31, 2001 or constructed before this date but it has increased its output or undergone a major rebuild in lieu of retirement since then.

2.5.1 Renewable Energy Standard 2010

(1) In each of the calendar years 2010, 2011 and 2012, each load serving entity must supply its customers with renewable low impact electricity in an amount equal to or greater than 5% of its total sales for that year

(2) Each load serving entity must meet the renewable energy standard in subsection (1) by supplying renewable low impact electricity by a renewable energy generation facility

(3) Subject to subsection (4), NSPI must purchase from independent power producers enough renewable low impact electricity to meet the renewable energy standard in subsection (1) for both its own retail sales and for sales to the 6 municipal electric utilities

(4) To meet the renewable energy standard in subsection (1), a municipal electric utility that purchases any of its electricity supply from a person other than NSPI must ensure that a minimum of 5% of that non-NSPI electricity supply is supplied by a generator of renewable low impact electricity.

2.5.2 Renewable Energy Standard 2013

(1) Each year beginning with the calendar year 2013, each load serving entity must supply its customers with renewable low impact electricity in an amount equal to or greater than 10% of its total sales for that year

(2) Each load serving entity must meet the renewable energy standard in subsection (1) by supplying renewable low impact electricity produced by a renewable energy generation facility

(3) Subject to subsection (4), NSPI must meet the renewable energy standard in subsection (1) as follows:

(a) by continuing to meet the 2010 standard by complying with subsection (3) of the renewable energy standard 2010

(b) by acquiring the additional renewable low impact electricity to meet the standard in subsection (1) from independent power producers or from its own renewable energy generation facilities.

(4) To meet the renewable energy standard in subsection (1), a municipal electric utility that purchases any of its electricity supply from a person other than NSPI must ensure that a minimum of 10% of that non-NSPI electricity supply is supplied by a generator of renewable low impact electricity.

The renewable low impact energy includes the electric energy produced using (1) solar energy, (2) wind energy, (3) biomass, (4) run-of-the-river hydroelectric energy, (5) ocean powered energy, (6) tidal energy, (7) wave energy, (8) landfill gas, and (9) liquid biofuel and other biogas energy.

2.6 NSPI 2007 Integrated Resource Plan

In collaboration with the UARB staff and its consultants, and with Integrated Resource Plan (IRP) process stakeholders, NSPI developed and submitted its 2007 long term resource plan in July 2007 for the UARB's consideration. The recommended plan in the IRP integrates supply and demand-side options to provide a strategic framework for meeting environmental legislation and regulations, cost effectively and reliably.

The major factors considered in the 2007 IRP include demand side management programs, system load growth, environmental emissions, fuel prices, operation and maintenance costs, investment requirements of new generation options, and generation system expansion reliability criteria.

The resource expansion plans studied in the 2007 IRP include the Reference, DSM, Renewables, Coal (FGD in 2020), Coal (FGD in 2012) and Gas Plans. Based on the calculated results, the Reference Plan has been recommended as NSPI's Preferred Resource Expansion Plan.

As the assumptions used in the 2007 IRP are also applied in this Wind Integration Study, some of these assumptions are summarized below.

2.6.1 Demand Side Management Programs

Over the past decade NSPI has worked successfully with customers to establish a demand response program. The programs have been primarily rate design-driven and today include interruptible pricing for large industrials, time of day pricing for residential customers with systems to shift heating loads, and the Extra large Industrial Two Part Real Time Pricing rate for NSPI's two largest customers. NSPI also provides customers educational materials regarding energy efficiency and conservation and supports a variety of small scale initiatives across Nova Scotia each year.

2.6.1.1 Conservation and Energy Efficiency

As part of its 2006 Rate Application, NSPI proposed to invest an incremental $5 million in conservation and energy efficiency programs. In support of this, NSPI submitted a proposed 2006 Conservation and Energy Efficiency Plan to the UARB. In its decision issued on March 10, 2006, the UARB concluded that the plan would benefit from additional design work. The Board directed NSPI "to retain an outside consultant and to complete the Plan's design and development".

On September 8, 2006, NSPI filed its Direct Evidence on DSM including its Revised DSM Plan (proposed General DSM programming) and Summit Blue's DSM report (Consultant's DSM report). On September 28, 2006 the Board advised NSPI that it would reserve its decision on whether or not to hold a hearing with respect to NSPI's revised DSM Plan filing until the IRP process was completed.

For the purpose of modelling DSM within the IRP, DSM program cost and energy and capacity savings information were required, ideally across various customer segments. NSPI relied on the work of its consultant, Summit Blue Consulting LLC for this information. In its DSM report, Summit Blue recommended spending by NSPI on DSM programs equal to 2% of electric revenue. The consultant also provided a forecast of energy and demand savings at this level of spending. To test alternative DSM spending levels in the NSPI 2007 IRP, the consultant extrapolated these energy and demand savings to spending levels of 1% and 5% of electric revenue, corresponding to lower/higher achievement of the economic DSM potential identified in its September 2006 DSM report.

The NSPI 2007 IRP has identified its Reference Plan as the least cost generation expansion plan, which includes the RES requirement, DSM programs and additional wind power generation. This plan includes a DSM spending level of 5% of electric revenue. The table below presents the total firm capacity and energy savings projected to result from the proposed 5% spending level on DSM programs by sector, for the years studied in this project.

		2008	2010	2013	2020
Residential	**MW**	4.9	25.3	80.7	231.3
	GWh	23.4	117.2	342.2	917.1
Commercial	**MW**	2.5	13.2	44.7	143.6
	GWh	20.1	100.3	292.8	790.2
Industrial	**MW**	0.9	5.0	16.8	52.4
	GWh	34.4	171.8	501.7	1389.7
Total	**MW**(1)	**8.3**	**43.5**	**142.2**	**427.2**
	GWh	**77.8**	**389.2**	**1136.7**	**3097.0**

(1) At time of system peak

The projected DSM achievement is a significant factor in the IRP process and this study. It could have significant impact not only on generation system operation cost but also on the generation system expansion sequence. If more reduction on peak and energy demands is achieved through DSM programs, the system could have surplus generation capacity so that some additions or upgrades could be delayed. Conversely, if the targets are not achieved, the system might not have enough generation capacity to meet load requirements and this would result in more interruptions of firm load. This implies that the generation expansion sequence could be changed if either higher or lower than projected DSM achievements materialize. Sensitivity analysis of the impact of DSM achievements is beyond the scope of this study.

2.6.1.2 Interruptible Load

The NSPI 2007 Tariff Schedule includes tariffs for various classes of industrial customers. These tariffs establish that three groups of industrial customers will be subject to interruptions for reasons of supply integrity. In case of capacity shortfalls, NSPI will call these industrial customers in the following priority order to provide capacity or reduce their consumptions:

(1) Customers providing Generation Replacement and Load Following services (GRLF Rate)

(2) Customers subscribing to the Extra Large Industrial Interruptible Rate-2 (ELIIR-2), and Extra Large Industrial Two Part Real Time Pricing Tariff (ELI 2P-RTP Rate)

(3) Large Industrial Customers subscribing to the Interruptible Rider.

Interruptions to power supply will be for supply shortfall reasons. As industrial customers may have also subscribed to (1) the Extra High Voltage Time-of-Use Real Time Pricing Tariff, (2) the High Voltage Time-of-Use Real Time Pricing Tariff, or (3) the High Voltage Time-of-Use Real Time Pricing Tariff, they may elect to reduce their demands for economic reasons.

A supply interruption is defined as a request by NSPI for a customer to reduce load in order to avoid shortfalls in electricity supply. In case of supply interruption, notification will be given no less than 10 minutes prior to the starting time of a supply interruption of the entire subscribed load or any portion thereof. Supply interruptions will be limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours per year.

The forecast interruptible loads for the years 2008, 2010, 2013 and 2020 are 385, 394, 407 and 434 MW respectively.

2.6.2 System Load Forecast

The load forecast used in the NSPI 2007 IRP was based on the 2006 NSPI Load Forecast prepared in September 2007 by the Revenue Operations group in NSPI. This forecast provides a long-term outlook of the energy and peak demand requirements of in-province customers and describes the considerations, assumptions and methodology employed.

The forecast was based on analysis of sales history, economic indicators, customer surveys, technological and demographic changes in the market, and the price and availability of other energy sources. Weather conditions, in particular temperature, affect the energy and peak demands. The forecast was based on the 30-year average temperatures measured in the Halifax area of the province. The NSPI Sales Forecast provides the basis for the financial planning and overall operating activities for the Company.

The table below presents the most likely case load forecast for the years studied in this project. In addition to this, it also includes the projected DSM achievements and forecast interruptible (non-firm) load. The generation system should be planned to meet the forecast firm peak and energy requirements at the prescribed reliability levels.

Year	Total Peak	DSM Savings (MW)	Non-Firm Load	Firm Peak	Total Energy	DSM Savings (GWh)	Energy Requirement	Load Factor (%) Firm Peak	Load Factor (%) Firm & Non-Firm
2008	2,312	8	385	**1,919**	13,272	78	**13,194**	78.50	65.38
2010	2,413	44	394	**1,975**	13,812	389	**13,423**	77.56	64.67
2013	2,548	142	407	**1,999**	14,542	1,137	**13,405**	76.56	63.61
2020	2,866	427	434	**2,005**	16,232	3,097	**13,135**	74.79	61.48

The load factors presented in the table above are calculated based on the firm energy and two different annual peak loads, firm peak load, and firm peak load plus non-firm load (total peak less DSM savings). The system has very high load factors if the calculations are based on the annual firm peak loads. The annual firm peak loads are used in the supply and demand balance tables to assess the system status of supply, i.e. short fall or surplus of generation capacity.

In system daily operation, the non-firm load will be interrupted only if there is a capacity short fall. Based on the descriptions presented in Subsection 2.6.1.2, the Hatch Study Team and NSPI decided that in system modelling simulations, the system annual peak demand includes both firm peak and non-firm peak load. The load factors accounting for this consideration are presented in the last column of the table above. It can be seen from this table that on this basis the system has relatively low load factors. Another important observation is that the system load factor is projected to decrease steadily over the period of analysis.

2.6.3 Generation Expansion Criteria

NSPI considers that a minimum of 20% firm capacity reserve above firm loads is required for all generation system expansion plans. This criterion has been demonstrated to comply with the NPCC (Northeast Power Coordinating Council) reliability criterion of less than 0.1 days of firm load interruption per year.

It is understood that the criterion of 20% firm capacity reserve is a deterministic measurement of the generation system while the criterion of 0.1 days per year is a probabilistic measurement, which is generally referred to as the LOLP criterion. It is also understood that the LOLP criterion of 0.1 days per year may result in various actual firm capacity requirements as the LOLP calculation depends on such factors as (1) annual peak load and energy demands, (2) load demand curve, (3) generating unit size, (4) unit planned outage rate, (5) scheduling of unit planned outages, (6) unit forced outage rate, (7) unit cycling capability, (8) unit peaking capability, (9) fuel availability including water availability for hydroelectric units/plants, (10) energy production of generating units with variable output, and (11) others. Calculation of generation system LOLP values is beyond the scope of this study.

2.6.4 Environmental Pollutant Emissions

The total emissions from the Nova Scotia power sector, and their financial impacts, were assessed based on the following four groups of assumptions:

(1) Air emissions included in the 2007 IRP

(2) Presumed annual emission caps for the Nova Scotia power sector

(3) Presumed air pollutant emission intensities of thermal units

(4) Presumed carbon offset prices.

2.6.4.1 Air Pollutant Emissions

There are many substances in the air which arise from both natural processes and human activity, and may impair the health of plants, animals and humans or reduce visibility. Substances not naturally found in the air or at greater concentration or in different locations from usual are referred to as pollutants. Based on the identified impacts of the pollutants on human life and environment, they can be divided into three groups, greenhouse gases (GHG), criteria air contaminants (CACs) and Others.

The impacts of GHG and CACs are a global concern. Scientific research is increasingly certain that anthropogenic GHG emissions are creating a discernable impact on the Earth's climate. The main GHG emissions include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), perfluorocarbons (PFCs), sulphur hexafluoride (SF_6) and hydrofluorocarbons (HFCs).

CACs, including volatile organic compounds (VOCs), sulphur oxides (SO_x), nitrous oxides (NO_x), carbon monoxide (CO) and particulate matter have been shown to cause adverse health and environmental impacts.

The air pollutants which are not included in the GHG and CACs groups belong to the Others group.

The air pollutant emissions considered in the 2007 IRP include CO_2, SO_2, NO_x and Hg (mercury) and this study considers these four pollutants. Mercury is present in coal, petcoke and oil and is released to air when these fuels are burned. There is growing evidence that mercury pollution at relatively low levels from man-made sources poses a serious threat to the environment and public health, but there is still considerable debate over the most effective and politically acceptable means for eliminating this pollution.

2.6.4.2 Presumed Annual Emission Caps for the Nova Scotia Power Sector

In the 2007 IRP, emissions caps were presumed in three different cases, most likely, low and high. As the objective of this project is to study the impact of wind power integration on the Nova Scotia electric system, only the emission caps for the most likely case are considered in this study. The table below presents the presumed annual emission caps for CO_2, SO_2, NO_x and Hg.

Year	NO_x KT/Year	CO_2 MT/Year	SO_2 KT/Year	Hg Kg/Year
2008		10	108.80	168
2010	21.44	10	72.50	65
2013	21.44	10	72.50	65
2020	14.70	10	36.25	34

The Nova Scotia power sector is subject to a future nitrogen oxides constraints as outlined in the provincial 2005 Air Quality Regulations. Starting from 2009, the system wide nitrogen oxides cap is 21.44 kilo-Tonne per year, which is 20% below base year 2000 emissions of 26.8 kilo-Tonne. By 2020 the nitrogen oxides cap would be reduced to 14.7 kilo-Tonne per year, which is approximately 30% lower than the 2009 emissions cap. This would require an adoption of another stage of NO_x reductions in the Nova Scotia power sector but not fleet-wide implementation of best available technology.

The CO_2 emission cap was set at 10 million-Tonne per year and is not varied over the study period. However, the CO_2 emissions are weighted with an allowance costs, which will be described later in Subsection 2.6.4.4.

As per the provincial 2005 Air Quality Regulations, the sulphur dioxide emission cap for the power sector is 108.8 kilo-Tonne for years from 2006 to 2009, which is a 25% reduction compared with the pre-2005 cap of 145 kilo-Tonne per year. From 2010 to 2019, the sulphur dioxide emission cap will be reduced to 72.5 kilo-Tonne per year, which is two thirds the 2009 cap. By 2020, the emission cap will be further reduced to 36.25 kilo-Tonne per year, which is half of the 2010 cap.

As outlined in the provincial 2005 Air Quality Regulations, the mercury cap for the Nova Scotia power sector for the period from 2006 to 2009 is 168 kg per year, which is 30% below the 1995 base year emissions of 240 kg. By 2010, the annual mercury emission cap will be further reduced to 65 kg per year, i.e. an approximate 61% reduction from the previous level. It is expected the mercury cap will be reduced to 34 kg per year by 2020, which would represent an approximately 80% reduction from the 2006 level.

2.6.4.3 Presumed Air Pollutant Emission Intensities

In order to reduce the emissions of pollutants and meet the annual emission caps, the NSPI 2007 IRP recommends the following actions:

(1) Increasing annual spending on DSM program

(2) Increasing energy generation from renewable resources such as hydro, wind, biomass, tidal, etc.
(3) Reducing the usage of fuels with high emissions and increasing the usage of fuels with low emissions

(4) Reducing the usage of fuels by converting simple cycle gas turbines into combined cycle plant

(5) Applying an allowance cost to account for CO_2 emissions

(6) Installing low NO_x burners on coal units

(7) Installing baghouse on Trenton 5 coal fired unit

(8) Installing selective catalytic reduction (SCR) and flue gas desulphurization (FGD) equipment for two coal fired units at Lingan plant.

Table 2-4 presents the fuels used by every individual thermal unit in the study years.

The emission intensities of thermal units, which were provided by NSPI and based on the Reference Plan in the 2007 IRP were used to calculate the annual pollutant emissions from each thermal unit and the total emissions from the power sector. Each of the annual total emissions will then be compared with the legislated or assumed cap. Due to their confidentiality, these emission intensities are not presented in this report.

2.6.4.4 Presumed Carbon Offset Prices

CO_2 emissions for each study year will be priced according to the carbon offset price forecast provided by NSPI. The offset prices are $15.06, $22.40 and $38.76 per tonne of CO_2 equivalent for 2010, 2013 and 2020 respectively.

2.6.5 Other Assumptions

There are also other important assumptions used in the NSPI 2007 IRP and this study, which include thermal unit heat rates, fuel prices, fixed and variable O&M costs, etc. These assumptions are not summarized in this report due to their confidentiality.

2.7 2007 Renewable Energy RFP

NSPI is committed to facilitating new renewable generation to be added to the Nova Scotia electrical grid. In 2006, some 12% of the electricity produced in Nova Scotia was generated from renewable sources including hydropower, wind, tidal, biomass, biogas. NSPI's 2007 Renewable Energy RFP is part of its efforts to increase energy generation from renewables.

The objective of the 2007 Renewable Energy RFP was to procure proven supplies of renewable energy from IPPs to be, as a minimum, in a position of compliance with the provincial Renewable Energy Standard 2010, at the lowest possible cost, over the full term of the power purchase agreement.

By issuing the 2007 Renewable Energy RFP, NSPI was seeking approximately 130 MW of new renewable generation from IPPs in two project size categories, a total of 100 to 130 MW from transmission connected developments and a total of 15 to 30 MW from distribution connected developments. The 2007 Renewable Energy RFP required that all successful projects would be in service by November 30, 2009.

Based on the proposals received and discussions with the project Advisory Committee, NSPI suggested that this study assume a total of 250 MW new wind power generation by 2010.

On November 19, 2007, NSPI announced that it was negotiating contracts with IPPs for a total of 240 MW of new renewable energy generation, as a result of its 2007 Renewable Energy RFP. It is expected that these generation facilities will be installed before the end of 2009. These new projects will be located at eight different sites throughout the province. By comparing this value with the 250 MW new wind capacity initially proposed by NSPI, there is only a difference of 10 MW and this small difference will not have a significant impact on the study results. It was decided therefore to retain the 250 MW capacity installation value for 2010.

Table 2-1: Existing Thermal Generating Units

Plant Name	Unit No.	Net Capacity (MW) MCR	Net Capacity (MW) Min Loading	Fuel Type	FOR (%)	PO (Weeks)	Cycling Capability	AGC Capability	Ramp Rate MW/Minute	In Service Year
Tufts Cove	1	81	45	HFO/NG	2.0	2	No	No	--	1965
	2	93	65	HFO/NG	2.0	2	Yes*	Yes	1~2	1972
	3	147	45	HFO/NG	2.0	2	Yes*	Yes	1~2	1976
Lingan	1	155	75	Coal/Petcoke	2.5	3.3	No	Yes	1~2	1979
	2	155	75	Coal/Petcoke	2.5	3.3	No	Yes	1~2	1980
	3	155	75	Coal/Petcoke	2.5	3.3	No	Yes	1~2	1983
	4	155	75	Coal/Petcoke	2.5	3.3	No	Yes	1~2	1984
Pt. Aconi	1	171	75	Coal/Petcoke	3.0	4	No	No	--	1994
Pt. Tupper	2	154	70	Coal/Petcoke	2.0	3	No	Yes	1~2	1973(1987)
Trenton	5	150	80	Coal/Petcoke	4.0	4	No	Yes	1~2	1969
	6	157	80	Coal/Petcoke	2.5	3	No	Yes	1~2	1991
Tufts Cove	4	49	5	NG	4.0	1	Yes	Yes	5+	2003
	5	49	5	NG	4.0	1	Yes	Yes	5+	2005
	6**	125	5	NG	4.0	1	Yes	Yes	5+	2010
Burnside	1	33	15	LFO	10.0	3	Yes	Yes	5+	1976
	2	33	15	LFO	10.0	3	Yes	Yes	5+	1976
	3	33	15	LFO	10.0	3	Yes	Yes	5+	1976
	4	33	15	LFO	10.0	3	Yes	Yes	5+	1976
Tusket	1	24	10	LFO	10.0	3	Yes	Yes	5+	1971
Victoria Junction	1	33	15	LFO	10.0	3	Yes	Yes	5+	1975
	2	33	15	LFO	10.0	3	Yes	Yes	5+	1975
		1893	**870**							

Note: * The unit needs 6 hour minimum down time and 12 hour minimum up time.
** The two Tufts Cove gas turbines are planned to be converted to combined cycle by 2010 and the 125 MW net capacity of this facility is not included in the total net capacity of 1,893 MW.

Table 2-2: Existing Hydroelectric Generating Plants

Plant Name	Firm Capacity (MW)	Annual Energy (GWh)
Wreck Cove*	210.0	304.0
Annapolis Tidal	3.7	30.8
Avon	6.8	23.9
Black River	22.5	88.6
Nictaux	8.3	41.6
Lequille	11.2	23.7
Paradise	4.7	20.7
Mersey	42.5	229.5
Sissiboo	24.0	73.8
Bear River	13.4	33.1
Tusket	2.4	11.6
Roseway	1.8	5.2
St. Margarets	10.8	24.9
Sheet Harbour	10.8	41.7
Dickie Brook	3.8	8.5
Fall River	0.5	2.3
Total	**377.2**	**963.9**

* The plant has two units, 115 MW each.

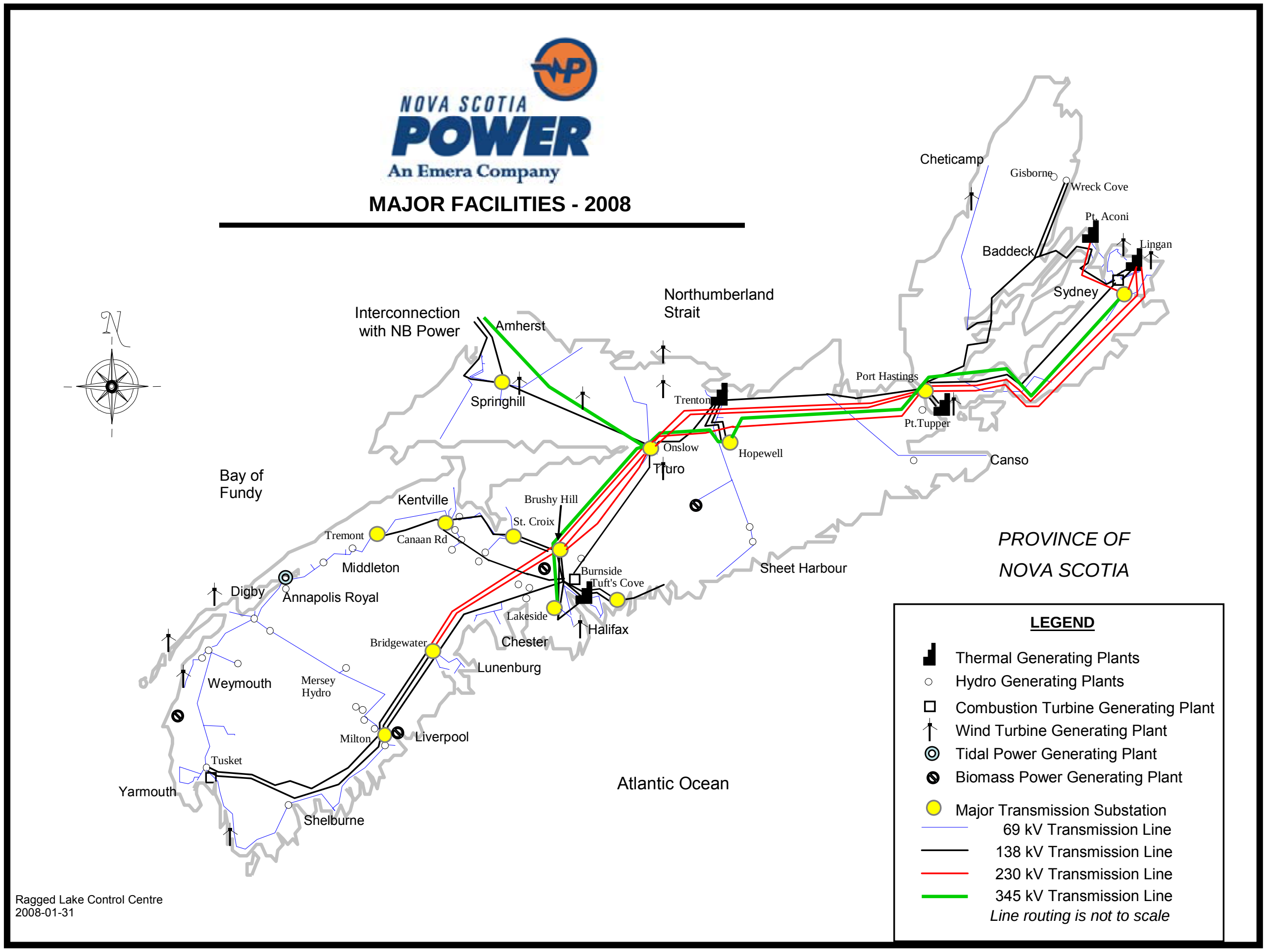
Table 2-3: Existing Wind Power Generation Projects

Location	Turbine Manufacturer	Installed Capacity	In Service Date	Owner
Little Brook	Turbowinds	0.6	Oct 2002	Nova Scotia Power
Grand Etang, Inverness County	Vestas	0.66	Oct 2002	Nova Scotia Power
Pubnico Point Phase 1	Vestas	3.6	Jan 2004	Atlantic Wind Power
Pubnico Point Phase 2	Vestas	27	Jan 2005	Atlantic Wind Power Corp.
Brookfield	Turbowinds	0.6	Nov 2005	Renewable Energy Services Limited
Glace Bay	Enercon	0.8	Nov 2005	Cape Breton Power
Donkin	Enercon	0.8	Nov 2005	Cape Breton Power
Goodwood, Halifax County	Turbowinds	0.6	Nov 2005	Renewable Energy Services Limited
Point Tupper	Enercon	0.8	Apr 2006	Renewable Energy Services Limited
Higgins Mountain	1.2 MW Vensys	3.6	Feb 2007	3G Energy Corp.
Tiverton	AWE	0.9	Apr 2007	3G Energy Corp.
Digby	Enercon E48 (800 kW)	0.8	Dec 2006	RESL
Fitzpatrick Mountain	Enercon	0.8	Apr 2006	Renewable Energy Services Limited
Fitzpatrick Mountain	Enercon E48 (800 kW)	0.8	Dec 2006	Renewable Energy Services Limited
Marshville	Enercon E48 (800 kW)	0.8	Dec 2006	Renewable Energy Services Limited
Lingan	Enercon	4	Jun 2006	Cape Breton Power
Lingan	Enercon	6	Dec 2006	Cape Breton Power
Lingan	Enercon	4	Jan 2007	Cape Breton Power
Springhill	Vensys	1.2	Dec 2005	3G Energy Corp.
Springhill	AWE	0.9	Nov 2006	3G Energy Corp.
Total		**59.3**		

Table 2-4: Fuel Used By Thermal Units

Plant Name	Unit No.	Net Capacity MCR	Fuel Type	Year 2008	2010	2013	2020
Tufts Cove	1	81	HFO/NG	HFO, NG	HFO, NG	HFO, NG	HFO, NG
	2	93	HFO/NG	HFO, NG	HFO, NG	HFO, NG	HFO, NG
	3	147	HFO/NG	HFO, NG	HFO, NG	HFO, NG	HFO, NG
Lingan	1	155	Coal/Petcoke	Low Sulphur Coal, Petcoke	Low Sulphur Coal, Petcoke	Low Sulphur Coal, Petcoke	Low Sulphur Coal, Petcoke
	2	155	Coal/Petcoke	Low Sulphur Coal, Petcoke	Low Sulphur Coal, Petcoke	Low Sulphur Coal, Petcoke	Low Sulphur Coal, Petcoke
	3	155	Coal/Petcoke	Low Sulphur Coal, Petcoke	Low Sulphur Coal, Petcoke	Low Sulphur Coal, Petcoke	Low Sulphur Coal, Petcoke
	4	155	Coal/Petcoke	Low Sulphur Coal, Petcoke	Low Sulphur Coal, Petcoke	Low Sulphur Coal, Petcoke	Low Sulphur Coal, Petcoke
Pt. Aconi	1	171	Coal/Petcoke	Coal, Petcoke	Coal, Petcoke	Coal, Petcoke	Coal, Petcoke
Pt. Tupper	2	154	Coal/Petcoke	Low Sulphur Coal	Low Sulphur Coal	Low Sulphur Coal	Low Sulphur Coal
Trenton	5	150	Coal/Petcoke	Low Sulphur Coal, Medium Sulphur Coal	Low Sulphur Coal	Low Sulphur Coal	Low Sulphur Coal
	6	157	Coal/Petcoke	Nova Coal, Petcoke	Low Sulphur Coal	Low Sulphur Coal	Low Sulphur Coal
Tufts Cove	4	49	NG	NG	--	--	--
	5	49	NG	NG	--	--	--
	6	125	NG	--	NG	NG	NG
Burnside	1	33	LFO	LFO	LFO	LFO	LFO
	2	33	LFO	LFO	LFO	LFO	LFO
	3	33	LFO	LFO	LFO	LFO	LFO
	4	33	LFO	LFO	LFO	LFO	LFO
Tusket	1	24	LFO	LFO	LFO	LFO	LFO
Victoria Junction	1	33	LFO	LFO	LFO	LFO	LFO
	2	33	LFO	LFO	LFO	LFO	LFO

Figure 2-1: NSPI Electric System



3. Major Assumptions for the Study

3.1 Introduction

This section provides a summary of the major assumptions used in carrying out this study.

3.2 System Parameters

A – Base Year

As per the requirements of the TOR for the study, 2007 is selected as the base year for the analysis. This means that all system information will be referred to the status as of January 1, 2007 unless mentioned otherwise.

B – Study Years

The TOR require a study period covering the horizon 2008 to 2020. In order to illustrate the impact of wind power integration, Hatch, based on consultation with the project Advisory Committee, has selected the following milestone years for detailed analysis - 2008, 2010, 2013 and 2020.

Year 2008 is the first study year, and it reflects the system status at the end of 2007.

The second year for detailed analysis is 2010. From this year to 2012, the system has to meet the provincial Renewable Energy Standard 2010. As this study is based on entire calendar years, all new capacity is assumed to be added to the system at either the beginning of the study year or the end of the previous year. Based on this assumption, the new renewable generating capacity selected to meet Renewable Energy Standard 2010 should be on-line by either the end of 2009 or the beginning of 2010.

Year 2013 is the first year when the system is required to meet the provincial Renewable Energy Standard 2013.

The last year for detailed study is 2020.

C – Typical Load Pattern

In order to carry out the tasks defined in the project TOR, Hatch needs to create one-minute and hourly load curves for the study years based on the forecast annual peak and energy demands. This is normally based on a given annual load pattern, which represents the most likely projection of system load demand in future years.

After discussion with NSPI, the system load pattern in 2005 was selected as typical as it was believed to be more representative than the load patterns in other recent years.

Figure 3-1 shows the system 2005 chronological hourly load curve. It can be seen from this figure that the system experienced highest load demands in January and December. It can also be seen that the system experienced low load demands during the Christmas Holiday season. The system also had low load demands during the Labour Day weekend in September. In general, the system load in the Summer season was lower than that in the Winter season.

Figure 3-2 to Figure 3-5 display graphically the forecast load in 2020 and the actual load in 2005, which were crated based on the forecast annual peak and energy demands as well as the 2005 hourly load pattern. Figure 3-2 and Figure 3-3 show the hourly load duration curves in MW and in per unit value (hourly loads divided by their corresponding annual peaks) for Years 2005 and 2020. Comparing with the 2005 load profile, the system will in 2020 experience lower hourly load demand in some hours due to the decrease in annual load factor. The 2005 load factor was approximately 66.1% while the 2020 load factor is projected to be about 61.5%.

Figure 3-4 shows the occurrence frequency of various system load levels in total number of hours while Figure 3-5 shows the cumulative occurrence frequency. It can be seen from Figure 3-4 that the load level ranging from 60% to 70% of the annual peak occurs most frequently, some 2,790 hours, compared with other levels of load. The load level ranging from 90% to 100% of the annual peak occurs least frequently within a year, for only about 110 hours.

D – Nova Scotia/New Brunswick Tie-Line

The analysis carried out in this study assumes that the Nova Scotia/New Brunswick Tie-Line is not a means to balance power system supply/demand in Nova Scotia. This decision was taken due to the lack of information on buying/selling volumes and prices and transmission system availability that needed for the dispatch model.

3.3 System Capacity Reserve Requirements

Working together with NSPI, Hatch has defined the following reliability criteria for use in this study:

(1) A minimum of 20% firm capacity reserve above firm loads is required for all generation system expansion plans, which is assumed in the 2007 IRP to comply with the NPCC (Northeast Power Coordinating Council) reliability criterion of less than 0.1 days of firm load interruption per year. It is worth to note that the 20% capacity reserve is calculated using a deterministic approach while the 0.1 days of interruption per year is calculated using a probabilistic method, which could be either analytical or Monte Carlo simulation

(2) Reserve sharing protocols with the New Brunswick System Operator (NBSO) and other utilities. The protocols include 10-minute and 30-minute operating reserve requirements with the 10-minute operating reserve including both spinning reserve and off-line reserve with quick start capability. Based on the system conditions (generating units and loads) in 2007, it has been determined that NSPI needs to carry 32 MW of spinning reserve, 140 MW of 10-minute quick start reserve and 70 MW of 30-minute reserve in its daily operation. As these values/rules are determined on an annual basis by all interested parties, it is very difficult to forecast the exact amount of these reserve requirements for the selected study years of 2008, 2010, 2013 and 2020. For example, the spinning reserve requirement is revised annually based on the Load Ratio Share between Nova Scotia and the remainder of the Maritimes and it is increased to 35 MW in 2008. After consultation with NSPI system operator, Hatch has assumed that the operating reserve requirements determined for 2007 can be kept unchanged for these study years as the size of NSPI's largest unit would not be changed before 2021 as per the current recommended generation system development plan. The 2020 forecast firm peak load of 2,005 MW will be only some 130 MW higher than the 2007 forecast firm peak load of 1,876 MW

(3) Based on consultation with NSPI, Hatch has assumed that the automatic generation control (AGC) and 10-minute load following requirements are calculated based on the standard deviations of 1-minute load or net load, (i.e. load minus wind power generation) and 10-minute load ramps respectively

(4) In PSS/E simulations, Hatch has included low load, high load and summer load conditions. Some of the NPCC reliability criteria were applied in the steady state assessment. To maintain the system reliability under the NPCC reliability criterion, a number of Special Protection Schemes (SPS) were developed in the 2013 steady state analysis and further updated in the 2020 steady state analysis.

3.4 Expansion Plans to 2020

The Renewable Energy Standards (RES) put in place by the Government of Nova Scotia require that 5% of the total Nova Scotia electricity requirement be supplied by new (post 2001) renewable energy sources by 2010, rising to 10% by 2013. In this regard:

(1) Achievement of these standards must be in the "most cost-effective way possible"

(2) There are some 1,500 MW of wind projects in the connection queue as of date of issue of this report

(3) Approximately 60 MW of wind generation has been installed post – 2001

(4) If all wind capacity, the RES will require some 180 MW of additional wind capacity by 2010 and a total of some 450 MW of additional wind capacity by 2013.

In order to carry out the tasks assigned to this project, Hatch has developed, in consultation with the Advisory Committee, three wind power integration plans based on the NSPI 2007 Integrated Resource Plan (IRP). They are:

(1) Base Plan – this is similar to the wind integration plan of the DSM Plan in the NSPI 2007 IRP with consideration of renewable generation proposals received by NSPI from its 2007 Renewable Energy RFP. The energy generated by the post 2001 renewable generation projects planned in this plan will meet/exceed the Nova Scotia RES 2013 requirements if the new renewable generation projects are fully implemented as per the proposed schedules. This plan will have 311 MW of wind capacity in 2010 and 581 MW of wind capacity in 2013 and 2020

(2) Alternative 1 Plan – this is similar to the wind integration plan of the Reference Plan in the NSPI 2007 IRP and it is based on the Base Plan described above. By 2020, this plan will have 200 MW more installed capacity of wind power generation projects than the Base Plan. The purpose of this plan is to examine the integration capability of wind power into the NSPI electric system and its associated impacts and costs in 2020. This plan will have 311, 581 and 781 MW of wind capacity in 2010, 2013 and 2020 respectively

(3) Alternative 2 Plan – this is based on the Alternative 1 Plan. By 2020, this plan will have 200 MW more installed capacity of wind power generation projects than the Alternative 1 Plan. The purpose of this plan is to examine the integration capability of a larger amount of wind power into the NSPI electric system by 2020 and to examine the associated impacts and costs in 2020. This plan will have 311, 581 and 981 MW of wind capacity in 2010, 2013 and 2020 respectively.

Table 3-1 presents the three wind power expansion plans which include the estimated firm capacity and installed capacity of wind plants. Based on the forecast firm energy demand (total energy demand minus DSM energy savings) and projected energy generation from the renewable resources, it was estimated that by 2010 a total of some 240 MW of wind plants would be required to meet the requirement of the RES 2010, which is 71 MW less than the value presented in Table 3-1. The over installation of wind plants was suggested by NSPI and was based on the submissions to the 2007 Renewable Energy RFP.

Starting from 2013 and onward, the system would need a total of some 510 MW of wind plants to meet the requirement of the RES 2013, which is also 71 MW less than the value presented in Table 3-1. This extra 71 MW of wind power installed capacity reflects the plans of the municipal electric utilities for installation of wind power generation units.

Three generation resource expansion plans were developed based on the three wind power integration plans presented in Table 3-1. These three resource expansion plans are presented in Table 3-2 to Table 3-4.

It is noted that in the three resource expansion plans developed, all system conditions are held constant except for the additions of new wind power projects. These unchanged conditions include system load demand forecasts (including both peak and energy), achievements of proposed DSM programs, forecast non-firm load, planned generating unit conversion and upgrades, and planed additions of generating units/plants. With these factors being unchanged, the three plans have varying amounts of surplus capacity in 2020 .

The generation capacity presented in these three tables is the net firm capacity. The net capacity means the gross generation capability less station services if applicable. The firm capacity of the existing renewable resources was calculated as per their actual annual capacity factors while the firm capacity of the future wind plants was calculated based on a presumption of 32% annual capacity factor.

It can be seen from these three tables that the total resources of installed capacity in the years 2008, 2010 and 2013 are equal. By 2020, the surplus capacity for the three plans is 123 MW, 187 MW and 251 MW respectively.

3.5 Allocation of New Wind Generation by Zone

3.5.1 Zonal Boundary

The project TOR mentions that some of the analysis will require the recognition of regional or zonal distribution of projects. The DOE had estimated that a total of five such regions or zones should provide sufficient granularity to address transmission constraints as well as meteorological diversity.

After discussion with NSPI and consultation with the Advisory Committee, it was decided that for the purposes of this study, the province of Nova Scotia would be divided into seven geographical zones, i.e. Sydney, Canso Strait, Pictou, Truro, Metro, West and Valley. The boundary of these seven zones is based on their geographical location and potential interconnection point of future wind power plants. As there is only very limited interest expressed for future wind power development in the Metro zone in the NSPI interconnection application queue, it has been assumed that all future wind power plants will be located in the remaining six zones.

Figure 3-6 shows a schematic form map of the province of Nova Scotia and the approximate boundary of the pre-defined seven zones, transmission and distribution lines and existing generation projects.

The following is a list of the potential interconnection point(s) for each of the six zones:

(1) Sydney – Victoria Junction and others

(2) Canso Strait – Port Hastings

(3) Pictou – Trenton and others

(4) Truro – Onslow

(5) West – Milton and others

(6) Valley – Canaan Road, St. Croix and others.

3.5.2 Allocation of New Wind Generation

To carry out the analysis required for this study, it is necessary to allocate the new wind plants presented in Subsection 3.4 to the six zones of the province, Sydney, Canso Strait, Pictou, Truro, West and Valley. This was performed through consultations with the Advisory Committee. The factors considered in the allocation of wind power capacity to these zones include:

(1) The renewable generation proposals received by NSPI as a result of its 2007 Renewable Energy RFP

(2) The expected annual capacity factor from the potential wind plants in each zone

(3) The estimated transmission capability to evacuate new wind power from each zone

(4) The estimated zonal transmission losses to transfer power to load centers

(5) The benefits of diversity of wind power generation projects.

At this time RES beyond 2013 have not been established. However there is an interest by many in society of moving to higher contributions from renewables due to increasing awareness of climate change. The study TOR specify that this study will consider an additional 200 MW of wind capacity (relative to the 2013 level) by 2020. In order to determine the relative impacts on the Nova Scotia electric system of a range of different levels of wind power installations, Hatch suggested to the Advisory Committee the three expansion plans introduced in Section 3.4 which, in summary, include the following levels of wind power installations for 2020:

(1) Base Plan – No change relative to RES 2013 requirement

(2) Alternative 1 Plan – 200 MW additional wind capacity relative to RES 2013 requirement

(3) Alternative 2 Plan – 400 MW additional wind capacity relative to RES 2013 requirement.

Combining these with the allocation factors given above resulted in the allocations of new wind power generation capacity by zone as shown in Table 3-5 and the zonal total wind generation capacities as shown in Table 3-6. Assuming an average installed capacity of 2 MW per wind turbine, the 520 MW of new wind power capacity shown in Table 3-5 by the year 2013 represents approximately 260 new wind turbines.

Creation of sub-zones within each zone and allocation of zonal new wind power generation capacity to these sub-zones would tend to reduce the overall variability of the wind power generation available to the system. As the future wind power generation projects would be developed through competitive RFP processes, there is no clear-cut basis to allocate the future staged wind power projects to each sub-zone. Another constraint factor for sub-zonal allocation of wind power generation capacity is the availability of sub-zonal wind time series data for all zones. After consultation with the Advisory Committee. It was decided that all future wind power generation projects within one zone would be represented by a single wind power generation time series and would be considered to be located at the designated bus for the zone.

It is noted that there are two options in 2010 for all three plans, two options in 2020 for Alternative 1 Plan and two options in 2020 for Alternative 2 Plan. The two options in 2010 were suggested by NSPI and were based on the generation proposals received from its 2007 Renewable Energy RFP. As the selection of the proposals was not finalized at the time of consultations, NSPI would prefer to study the impact of wind power integration in 2010 in the two suggested allocations.

The allocations of new wind generation capacity in 2013 are based on the allocations in 2010 and the weighting factors described previously. The objective is that there will be only one set of allocations in 2013. Before applying the weighting factors, the following amounts by zone have been determined:

(1) 110 MW In the Valley zone, which includes 40 MW from 2010 and 70 MW for municipal electric utilities

(2) 80 MW in the Truro zone, the highest amount in the two options in 2010

(3) 120 MW in the Pictou zone, the highest amount in the two options in 2010

(4) 110 MW in the Canso Strait zone, which is the sum of the two options in 2010 as these are from different projects.

The total capacity in the four items above is 420 MW. This means that only 100 MW (the difference between a total of 520 MW and the fixed amount of 420 MW) is allocated in 2013 based on the weighting factors.

In Option 1 of Alternative 1 Plan for 2020, 200 MW of new wind plants is allocated to the Canso Strait zone. In this case, a new 345 kV transmission line running from Canso Strait to Metro would be required to be constructed to transfer the wind power to the load centers.

In Option 2 of Alternative 1 Plan for 2020, it was assumed that the new 345 kV transmission line that would be needed in Option 1 will not be built. In this case, a total of 200 MW of wind power is allocated to the West (100 MW), Valley (50 MW) and Truro (50 MW) zones.

Both options of Alternative 2 Plan need the 345 kV transmission line running from Canso Strait to Metro. Option 1 of Alternative 2 Plan is constructed based on Option 1 of Alternative 1 Plan. In this option, the additional 200 MW of wind power is allocated to the West and Truro zones, each with 100 MW.

Option 2 of Alternative 2 Plan is based on Option 2 of Alternative 1 Plan. In this option, 200 MW of wind power is added to the system in the Canso Strait zone.

Table 3-1: Wind Power Integration Plans

		Year			
		2008	2010	2013	2020
Base Plan	**Firm Wind (MW)**	22	102	189	189
	Wind Equivalent (MW)	61	311	581	581
Alternative 1 Plan	**Firm Wind (MW)**	22	102	189	253
	Wind Equivalent (MW)	61	311	581	781
Alternative 2 Plan	**Firm Wind (MW)**	22	102	189	317
	Wind Equivalent (MW)	61	311	581	981

Table 3-2: Generation Capacity and Peak Demand Balance – Base Plan

	2007	2008	2010	2013	2020
Total Load	2,257	2,312	2,413	2,548	2,866
DSM (Firm)	0	8	44	142	427
Total Load Less DSM	2,257	2,304	2,369	2,406	2,439
Non-Firm Load	381	385	394	407	434
Firm Peak	1,876	1,919	1,975	1,999	2,005
Reserve Requirement (20%)	375	384	395	400	401
Total Resources Required	2251	2302	2371	2399	2406
Existing Resources					
Thermal	1893	1893	1893	1893	1893
Hydro	377	377	377	377	377
IPP (Pre 2001)	26	26	26	26	26
RES (Post 2001)	18	22	22	22	22
Subtotal	**2314**	**2318**	**2318**	**2318**	**2318**
Upgrades and New Additions					
RES	0	0	80	145	145
Municipal Utilities				22	22
Renewables Beyond 2013 RES					
Nictaux (Hydro)			2.5	2.5	2.5
Marsh (Hydro)			1.8	1.8	1.8
Conversion of TUC GTs to CC			27	27	27
Lingan 2 Upgrade			5	5	5
Lingan 4 Upgrade			5	5	5
Lingan 3 Upgrade				5	5
Lingan 1 Upgrade				5	5
FGD LIN 1/2 (Parastic power)					-8
Subtotal	**0**	**0**	**122**	**218**	**210**
Total Resources	**2314**	**2319**	**2440**	**2537**	**2529**
Surplus/Deficit	63	16	69	138	123
Surplus/Deficit (% of Firm Peak)	3.4	0.8	3.5	6.9	6.1

Table 3-3: Generation Capacity and Peak Demand Balance – Alternative 1 Plan

	2007	2008	2010	2013	2020
Total Load	2,257	2,312	2,413	2,548	2,866
DSM (Firm)	0	8	44	142	427
Total Load Less DSM	2,257	2,304	2,369	2,406	2,439
Non-Firm Load	381	385	394	407	434
Firm Peak	1,876	1,919	1,975	1,999	2,005
Reserve Requirement (20%)	375	384	395	400	401
Total Resources Required	2251	2302	2371	2399	2406
Existing Resources					
Thermal	1893	1893	1893	1893	1893
Hydro	377	377	377	377	377
IPP (Pre 2001)	26	26	26	26	26
RES (Post 2001)	18	22	22	22	22
Subtotal	**2314**	**2318**	**2318**	**2318**	**2318**
Upgrades and New Additions					
RES	0	0	80	145	145
Municipal Utilities				22	22
Renewables Beyond 2013 RES	0	0	0	0	64
Nictaux (Hydro)			2.5	2.5	2.5
Marsh (Hydro)			1.8	1.8	1.8
Conversion of TUC GTs to CC			27	27	27
Lingan 2 Upgrade			5	5	5
Lingan 4 Upgrade			5	5	5
Lingan 3 Upgrade				5	5
Lingan 1 Upgrade				5	5
FGD LIN 1/2 (Parastic power)					-8
Subtotal	**0**	**0**	**122**	**218**	**274**
Total Resources	**2314**	**2319**	**2440**	**2537**	**2593**
Surplus/Deficit	63	16	69	138	187
Surplus/Deficit (% of Firm Peak)	3.4	0.8	3.5	6.9	9.3

Table 3-4: Generation Capacity and Peak Demand Balance – Alternative 2 Plan

	2007	2008	2010	2013	2020
Total Load	2,257	2,312	2,413	2,548	2,866
DSM (Firm)	0	8	44	142	427
Total Load Less DSM	2,257	2,304	2,369	2,406	2,439
Non-Firm Load	381	385	394	407	434
Firm Peak	1,876	1,919	1,975	1,999	2,005
Reserve Requirement (20%)	375	384	395	400	401
Total Resources Required	2251	2302	2371	2399	2406
Existing Resources					
Thermal	1893	1893	1893	1893	1893
Hydro	377	377	377	377	377
IPP (Pre 2001)	26	26	26	26	26
RES (Post 2001)	18	22	22	22	22
Subtotal	**2314**	**2318**	**2318**	**2318**	**2318**
Upgrades and New Additions					
RES	0	0	80	145	145
Municipal Utilities				22	22
Renewables Beyond 2013 RES	0	0	0	0	128
Nictaux (Hydro)			2.5	2.5	2.5
Marsh (Hydro)			1.8	1.8	1.8
Conversion of TUC GTs to CC			27	27	27
Lingan 2 Upgrade			5	5	5
Lingan 4 Upgrade			5	5	5
Lingan 3 Upgrade				5	5
Lingan 1 Upgrade				5	5
FGD LIN 1/2 (Parastic power)					-8
Subtotal	**0**	**0**	**122**	**218**	**338**
Total Resources	**2314**	**2319**	**2440**	**2537**	**2657**
Surplus/Deficit	63	16	69	138	251
Surplus/Deficit (% of Firm Peak)	3.4	0.8	3.5	6.9	12.5

Table 3-5: Allocations of New Wind Power Generation by Zone

	Zone						
	West	Valley	Truro	Pictou	Canso Strait	Sydney	Total
				All Three Plans			
New Installation by 2010							
Option 1	0	40	50	60	100	0	250
Option 2	0	40	80	120	10	0	250
New Installation by 2013	30	110	110	140	110	20	520
				Base Plan			
New Installation by 2020	30	110	110	140	110	20	520
				Alternative 1 Plan			
New Installation by 2020							
Option 1	30	110	110	140	310	20	720
Option 2	130	160	160	140	110	20	720
				Alternative 2 Plan			
New Installation by 2020							
Option 1	130	110	210	140	310	20	920
Option 2	130	160	160	140	310	20	920

Table 3-6: Zonal Total Wind Power Generation

	West	Valley	Truro	Zone Pictou	Canso Strait	Sydney	Total
Existing Installation (2007)	31.2	1.9	7.5	2.7	0.9	16.3	61
				All Three Cases			
Total Installation by 2010							
Option 1	31.2	41.9	57.5	62.7	100.9	16.3	311
Option 2	31.2	41.9	87.5	122.7	10.9	16.3	311
Total Installation by 2013	61.2	111.9	117.5	142.7	110.9	36.3	581
				Base Plan			
Total Installation by 2020	61.2	111.9	117.5	142.7	110.9	36.3	581
				Alternative 1 Plan			
Total Installation by 2020							
Option 1	61.2	111.9	117.5	142.7	310.9	36.3	781
Option 2	161.2	161.9	167.5	142.7	110.9	36.3	781
				Alternative 2 Plan			
Total Installation by 2020							
Option 1	161.2	111.9	217.5	142.7	310.9	36.3	981
Option 2	161.2	161.9	167.5	142.7	310.9	36.3	981

Figure 3-1: 2005 System Hourly Load Curve

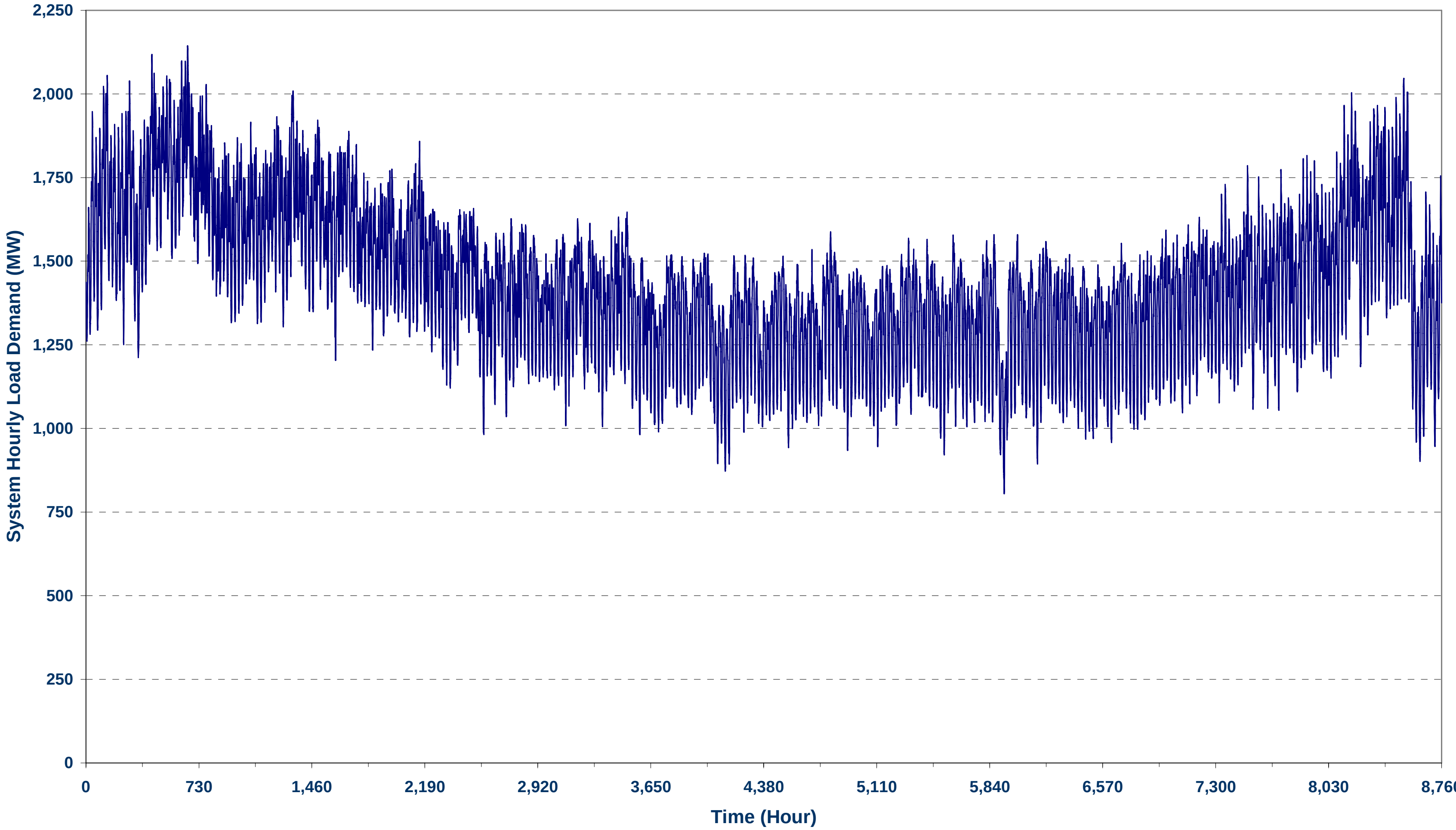


Figure 3-2: Hourly Load Duration Curve

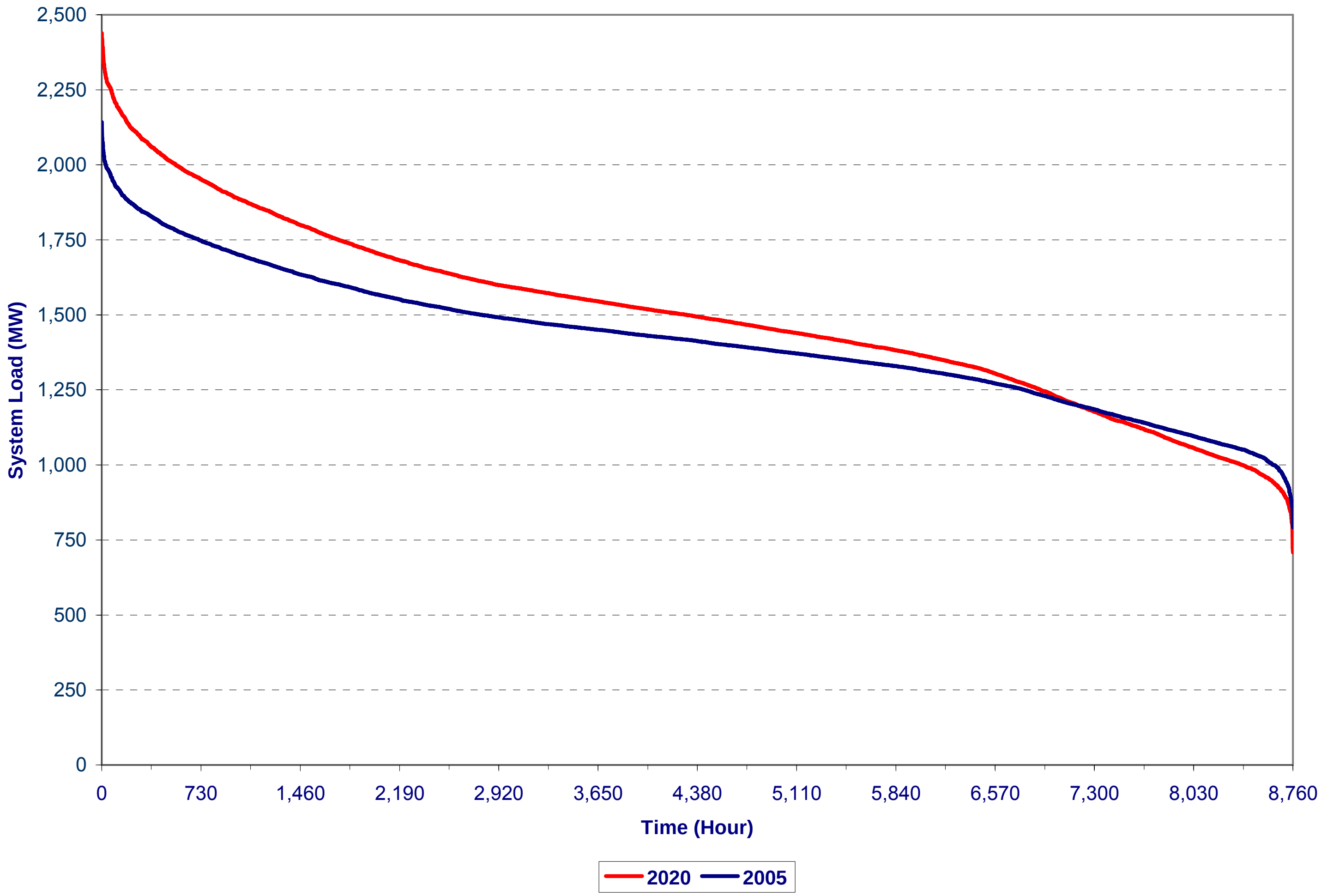


Figure 3-3: Hourly Load Duration Curves in Per Unit

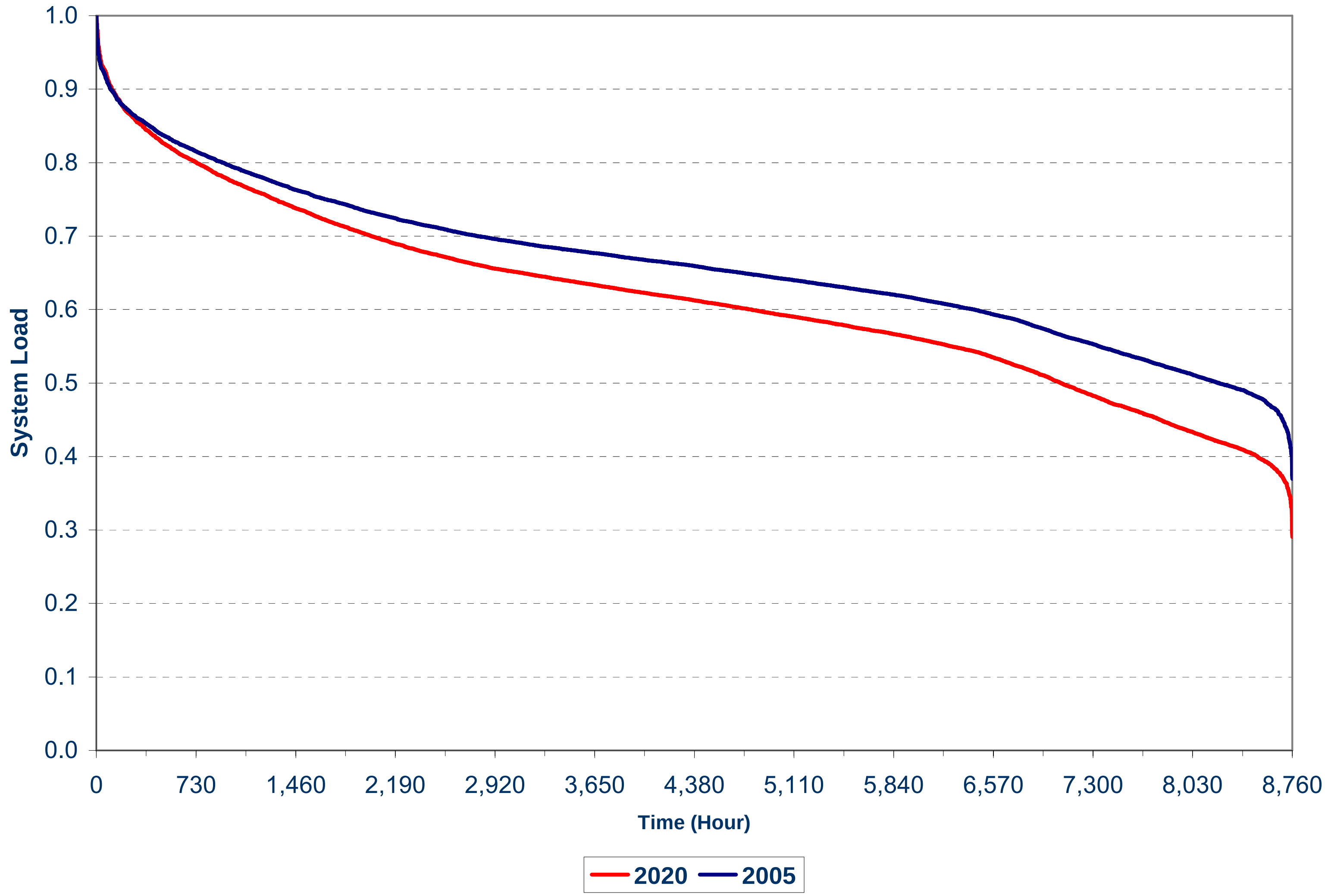


Figure 3-4: Occurrence Frequency of System Hourly Load in 2020

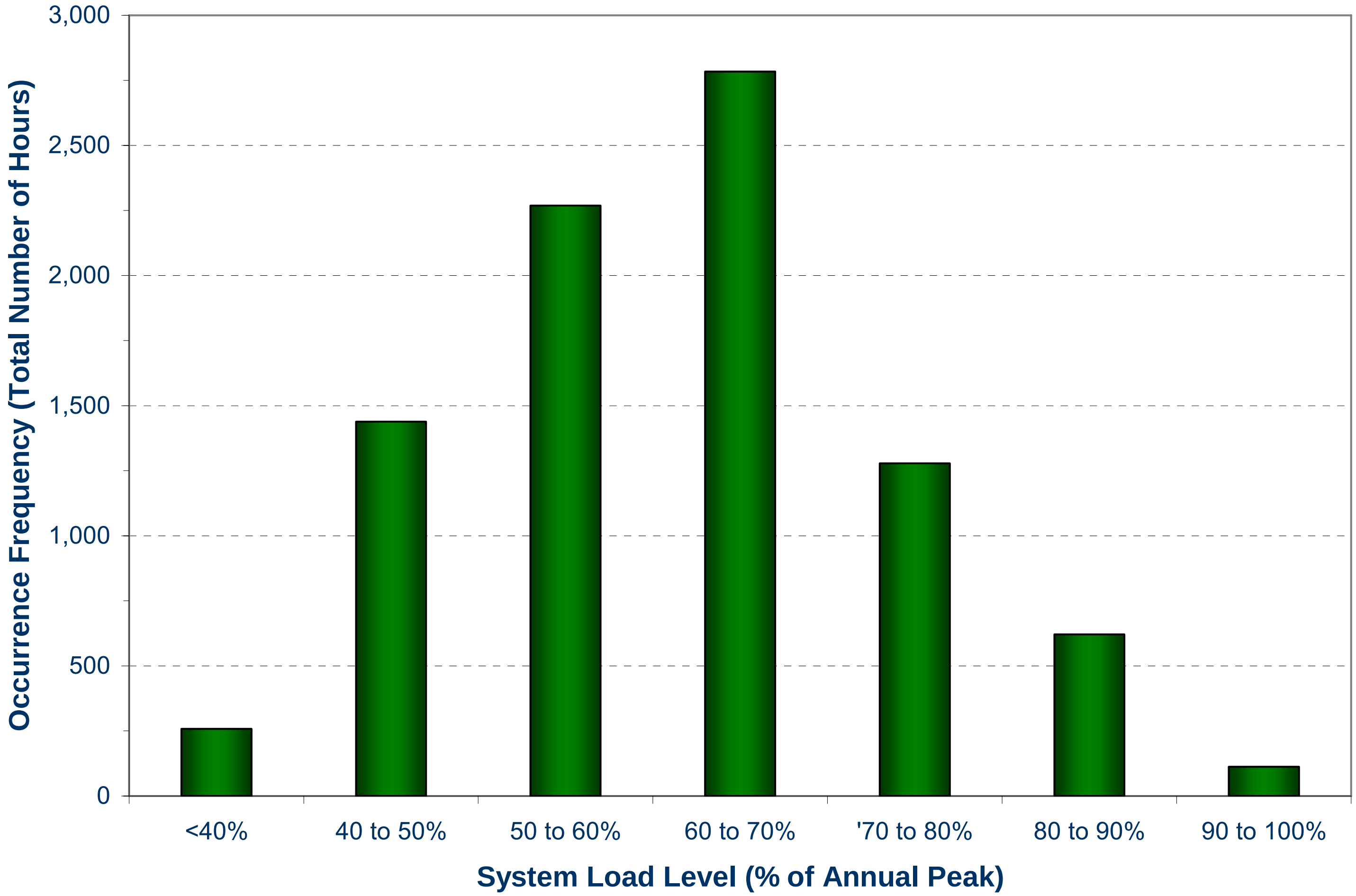


Figure 3-5: Cumulative Occurrence Frequency of System Hourly Load in 2020

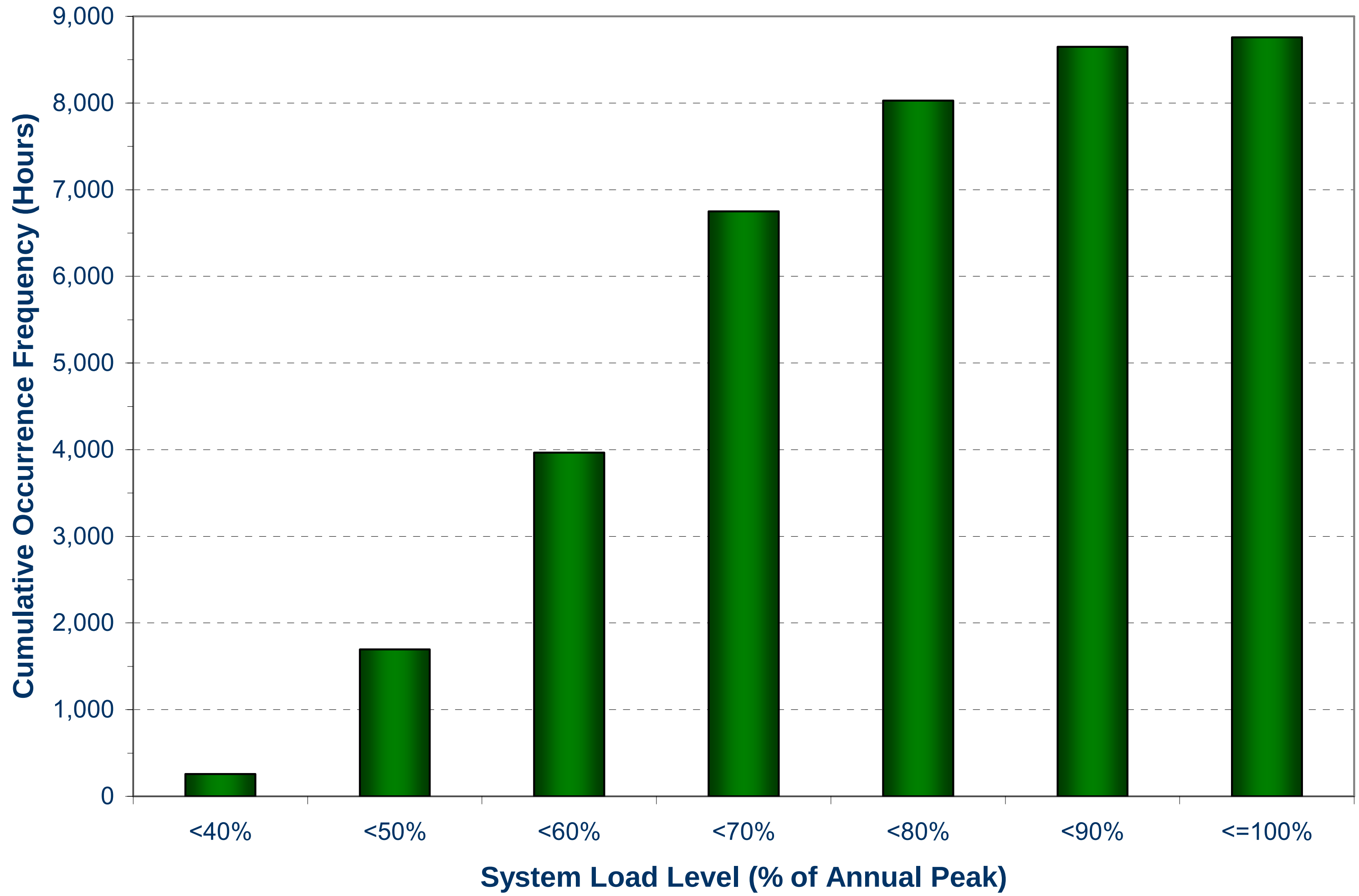
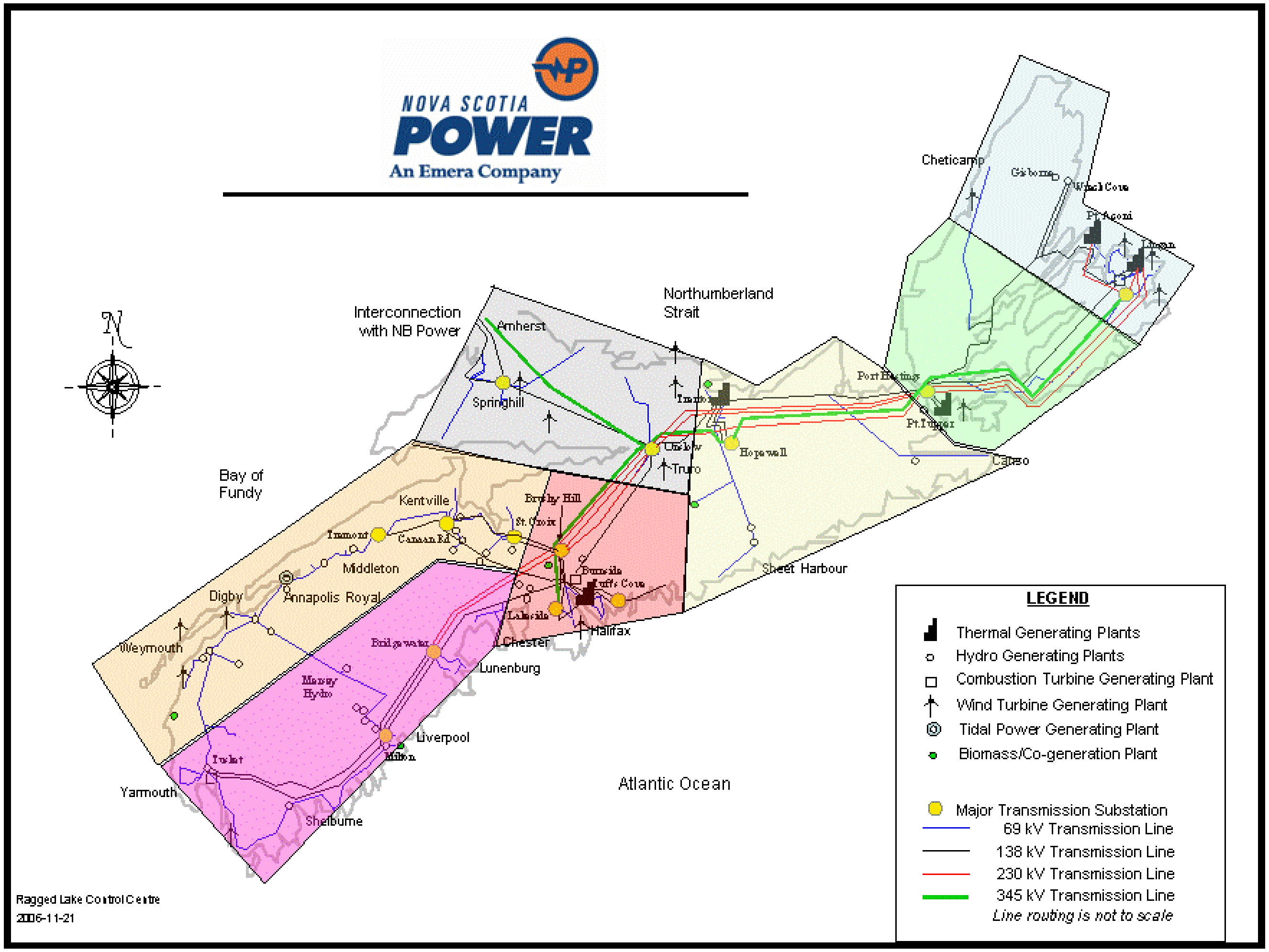


Figure 3-6: Zonal Boundary



4. Wind Resource Data

4.1 Introduction

This section describes the data received, the data screening, validation and selection procedures and the assessment of the wind climate variability. In addition, methodology and discussions are presented that outline the process to convert the wind resource data to generation by study zone, that describe the use and accuracy of wind energy forecasting and discuss the future of wind energy technology.

The study zones mentioned in this section are the same as those described in Section 3 and presented in Figure 3-6.

4.2 Description of Data Received

Wind data was collected for 15 NSPI towers, 24 Environment Canada climate data stations and 13 towers operated by 4 independent developers. The data sets cover various time horizons and the spatial dispersion of the towers covers all zones considered in this study. The minimum number of towers located in a particular zone was three and de maximum was eight. For easy understanding, Figure 4-1 presents one typical meteorological mast tower configuration.

The data provided by NSPI was received in raw form as stored in the NRG systems data loggers used at the met mast locations. The data sets contained wind speed, wind direction, and where applicable temperature and barometric pressure. All data was stored in 10-minute intervals, and wind speed and wind direction were measured at elevations of 10 m, 30 m and 50 m with redundant instrumentation (anemometers and vanes respectively) at 50 m.

Likewise, the data received from independent developers contained 10-minute average wind speed, and wind direction and temperature and barometric pressure where applicable. The met masts used by the contributing private developers varied in height from 50 m to 60 m and had varying instrumentation configurations. However, all met masts contained redundant instrumentation at various elevations. The data received from the independent developers also varied in form, some raw as stored in the data logger, and some processed and validated independently, and delivered in various formats.

The Environment Canada climate stations data was obtained for all potential long-term reference stations (i.e. historical records longer than or equal to 10 years) containing hourly wind speed and wind direction. It should be noted that these records are not representative of hourly average values as Environment Canada records instantaneous readings after each hour. In addition, all data was measured at 10 m elevations above ground level without redundant instrumentation.

4.3 Data Validation and Selection

4.3.1 Data Screening

All data sets were subject to data screening using the following criteria:

- Continuity test (identify temporal gaps in data)
- Ensure observations and derived parameters are realistic:
    - Acceptable wind speed U range: $0 <= U <= 25$ m/s

  - Acceptable wind direction range: 0<=dir<= 360 degrees
  - Acceptable wind speed standard deviation range 0 <= sd <= 3.5 m/s, or sd <= 0.3*Wind Speed (applies to 10-minutes average data only)
  - Acceptable wind direction standard deviation range 0 <= sd <= 75 degrees (applies to 10-minutes average data only)
  - Acceptable range of temperature
  - Acceptable ranges of others (pressure etc)
- Ensure measurements at same height on mast are similar (if installed)
- Ensure similar trends are found between instruments on the same tower
- Low wind: U<0.4 m/s is not sufficient to activate wind vane therefore directions for low wind must be discarded/undefined
- Replace missing/suspect/rejected data with data from redundant sensor or flag with code indicating reason for rejection (i.e. icing, static discharge, operator error, wind vane deadband, shading by obstacle, missing data etc.)

The screening process illustrates anomalies as a result of data falling outside the ranges set by the criteria. This process yields the gross data recovery rate and the net data recovery rate. The gross recovery rate is simply the percentage of data recorded out of the total operational time span. The net recovery rate factors in the percentage of time that data falls outside of the screening criteria ranges listed above. Gross and net recovery rates obtained from the raw data during the data screening process ranged from 80 – 100% and 68 – 98% respectively. Gross and net recovery rates were improved through measure-correlate-predict (MCP) analysis procedures for infilling and/or replacing suspect data.

Hatch reviewed each anomaly and applied practical judgement to determine whether the data should be discarded, replaced or left as is.

4.3.2 Continuity and Temporal Gaps

Temporal gaps in the data sets were easily identified by reviewing plots of the wind speed time series as illustrated in Figure 4-2. Where possible, the gaps were filled using MCP analysis which minimizes the sum of the square of the error in the Y direction between the problematic instrument (Y values) and another instrument of the same type on the same tower (X values). The coefficient of determination (R^2) provides a measure of the strength of the relationship. The R^2 values range between 0 and 1, with 1 being a perfect correlation. MCP analysis was carried out for all data sets from all sources to assess data redundancy and mast to mast trends and relationships. For example, if a temporal gap was evident in a data set for a given tower, the suspect tower data was correlated to another tower to develop a trend for infilling data. Figure 4-3 illustrates a typical correlation between redundant anemometers on the same met mast.

4.3.3 Wind Shear

Wind speed generally increases with height above ground level. When wind speed is not directly measured at hub height, it is estimated by wind shear extrapolation methods. In order to assess the wind speed at a WTG hub height, wind shear relationships must be understood. Wind shear profiles were developed for each data set with the exception of the Environment Canada climate data sets which only contain measurements at 10 m elevations.

Wind shear profiles were developed by minimizing the sum of the square of the errors between the measured average wind speeds and the calculated average wind speeds at each instrument elevation for each tower.

Figure 4-4 provides an example of vertical wind speed extrapolation using the Log Law and Power Law wind shear relationship.

4.3.4 Wind Speed Frequency and the Weibull Distribution

Wind speed frequency histograms typically take the shape of the two-parameter Weibull probability distribution. As a result, the Weibull distribution was fit by minimizing the sum of the square of the errors between the measured wind speed frequency and the calculated Weibull frequency for every anemometer on each of the met towers for all data sets. The form of the Weibull distribution cumulative probability function is as follows:

$$f(x; k, A) = 1 - e^{-(x/A)^\wedge k}$$

Figure 4-5 provides an example of a wind speed frequency histogram and Weibull distribution fit.

4.3.5 Detection of Icing

Detection of icing is relatively complex. Traditional icing and dew point detectors, and relative humidity sensors were not installed on the subject met towers. As a result, assumed estimates of icing times were made by approximating the percentage of the total time that an instrument's standard deviation was zero while temperatures were at or below freezing. These periods were cross checked with the recorded data by the instrument to ensure the wind speed and/or wind direction did not change for the concurrent time periods.

4.3.6 Long-term Variability

To evaluate wind energy it is important to understand the long-term wind climate variability. Hourly average wind speeds from the Environment Canada climate data stations of varying lengths were analyzed and a period of 20 years was selected as the duration representative of the long-term wind climate variability. This length was selected to ensure that long-term data sets were available for each study region, and all data used was after Environment Canada implemented consistent measurement elevations of 10 m, which occurred throughout the 1970s.

Figure 4-6 and Figure 4-7 show the annual, 5-yr, 10-yr and long-term average wind speeds measured over the 20 year period at the Sydney Airport and Yarmouth Airport respectively. It is clear from the moving means plots that the wind speeds over the last few years have been lower than the long-term averages. As a result, wind energy output from existing wind farms and associated capacity factors are expected to increase, barring any major maintenance issues.

Hourly average wind speeds aggregated from the 10-minute average wind speeds from each met mast provided by NSPI and independent developers were correlated to the long-term reference station data for the appropriate study region. The correlation relationships that yield the highest coefficient of determination (R^2) were deemed applicable for use to adjust either NSPI data or independent developer data up or down to represent long-term average conditions.

The wind speed data recorded at each met tower was adjusted to ensure that the average wind speeds were representative of the long-term average wind climate. This was done by prorating the data with the ratio of averages as follows:

$$U_{LT\_10Min} = U_{Measured\_10Min} * (U_{LT\_Environment\ Canada} / U_{Measured\_Environment\ Canadas})$$

where,
U = average wind speed in m/s
LT denotes long-term 20 year period
Measured denotes the period of measurement for the given met mast

It is necessary to note that the long-term variability described in this subsection is based on the historical records of wind data. Any potential long-term impacts of climate change on wind speeds were not taken into consideration in either the analysis of historical long-term variability or the forecasting of future wind power generation.

4.3.7 Diurnal Trends

In addition to the long-term variability, the diurnal trends were analyzed spatially for each study zone. Figure 4-8 and Figure 4-9 illustrate the diurnal trends at a hub height of 78 m for the Sydney region and Valley region respectively. The diurnal trends are consistent across the province.

4.3.8 Data Selection

Overall, the quality of the data is believed to be satisfactory. However, some anomalies were evident in various data sets and attempts were made to correct for these anomalies as described in previous sections.

Once the data validation, infilling and/or extension MCP procedures were complete and all NSPI and independent developer data sets were adjusted to represent the long-term average wind climate, a single one year long 10-minute average data set was selected for each study zone. The representative data set was selected as one that provided average zone conditions resulting from the analyses presented in the previous sections.

For reasons of confidentiality, the selected data sets are not disclosed.

4.4 Conversion of Wind Resource Data to Generation by Zone

Spreadsheet models were developed for each study zone to convert the wind speed data sets to wind generation data sets. The primary input into the zonal models was the "cleaned" and validated one year wind speed time series. These data sets were sheared to a 78 m hub height and adjusted to represent the long-term average wind speed conditions. The selected data sets were then run through a wind turbine-generator (WTG) power curve to calculate the gross power output on a 10-minute average interval.

The WTG equipment considered in the analysis included the Vestas V82, the Vestas V90, the Gamesa G58, the GE 1.5 xle, and the Enercon E82. The Enercon E82 WTG was selected as a suitable representation of a typical 2 MW WTG. Figure 4-10 illustrates the power curves for the WTGs considered.

Different WTG technologies have various ways to handle high wind hysteresis. To account for the high wind hysteresis events in generic fashion, it was assumed that when wind speed exceeds 25 m/s for a 10-minute duration, the WTG output is reduced to 0 MW, and the unit remains offline for 30 minutes after the wind speeds return to an operable range.

In addition, the following losses were assumed to convert gross power output to net power output:

Source of Loss	Factor
WTG Unavailability	3.0%
Collection and Substation Unavailability	0.5%
Electrical and Transmission Loss	2.0%
Utility/Grid Availability	0.5%
Icing and Blade Degredation	3.0% (Sydney/Canso), 1% (Other)
Wake Induced Turbulence Loss	5.0%
Total Loss	**13.3% (Sydney/Canso), 11.3% (Other)**
Net / Gross Energy Scale Factor	**86.7% (Sydney/Canso), 88.7% (Other)**

These loss factors were applied to the average gross capacity for every interval using a 10-minute time step. As a result, the net annual energy output and the maximum output capacity available to the system at any time include these loss assumptions.

Table 3-6 presents the installed wind power capacity by zone and by year for the three generation development plans used in this study. To understand the impact of the above loss assumptions on the maximum output capacity to the system, Table 4-1 presents zonal wind power generation by year in terms of both name plate capacity and maximum output capacity to the system.

Once the net power output on a 10-minute average basis was obtained, the results were aggregated to hourly average power output for input to the power system simulations.

One minute wind power output was developed using the same set of assumptions. However, in order to obtain one-minute average wind speeds, a Monte Carlo simulation was developed using the Python platform to randomly generate 2 second data assuming that the 10-minute average wind speed and standard deviation provided in each time step of the selected data sets represent the two parameters that form a normal probability distribution. The 2 second data is consistent with the instrumentation measurement interval, and is aggregated by the data loggers at the met mast locations to 10-minute average data from which the standard deviation is calculated and stored accordingly. The randomly generated 2 second data was aggregated to one minute average wind speeds, and used as the primary input into the zonal one minute power output models. The one minute power output results were used in the capacity accreditation analysis, described later in Section 4.7.

4.5 Wind Power Forecasting

Wind generation variability is a concern for both system operators that need to take into account the output of connected wind power producers and for power producers that wish to participate in day-ahead markets. Typically, power producers are required to provide power in accordance with the amount and time they have scheduled with the system operator. Without proper forecasting tools, it is difficult for wind power producers to viably participate in day-ahead markets. Even with wind forecasting tools, some error between actual and forecasted generation is inevitable.

Wind forecasting is already an integral part of large wind operation systems in Europe, where wind penetration in a particular system can exceed 10% and wind generation variability is of concern. The Maritimes Area Wind Integration Study conducted by New Brunswick System Operator (NBSO) in 2005 states the following:

"If the installed wind generation capacity in the Maritimes becomes significant, it will be necessary for the Maritime power systems to have day-ahead hourly wind energy forecasts incorporated into their scheduling. Failure to do so will likely cause an inefficient scheduling of resources, and may result in extra costs to ratepayers or degradation to system reliability. Neither is acceptable."

Wind forecasting tools are not perfect and there will always be some error between predicted and actual wind generation. For example, hour-ahead predictions can be made with far greater accuracy than day-ahead predictions, as the time window increases, predictions are less accurate. For example, a study of wind forecast performance described in the New York Wind Integration Study (GE Energy, March 2005) shows that errors in day-ahead wind generation forecasts are expected to have standard deviations of approximately 400 MW, or 12% of the aggregate rating of all the wind generators (3,300 MW) and that errors in hour-ahead wind generation forecasts are expected to have standard deviations of approximately 145 MW, or 4.2%.

Power producers participating in day-ahead markets are typically required to provide power in accordance with the amount and time they have scheduled with the system operator and a considerable cost may be incurred by the power producer for correcting the difference between actual generation delivered and that scheduled. North American authorities deal with deviations from scheduled generation due to the intermittent nature of wind in a number of ways. A few examples are given below:

- ERCOT exempts wind power producers from scheduling penalties if actual generation is within 50-150% of generation predicted
- the California ISO allows wind generators to settle imbalances on a monthly basis rather than on the real-time market and requires wind farms to install metering and telemetry to monitor the wind at the site as well as wind farm status which is used in combination with a wind forecasting tool to estimate day-ahead generation. The ISO charges a fee associated with forecasting
- PJM and NYISO allow for real-time settlement of imbalances (PJM allows wind generators to buy shortcomings at market prices and NYISO allows wind to bid into the hour-ahead market).

Because of these concerns and the penalties associated with not meeting scheduled generation, forecasting tools are increasingly being used to improve the predictability of wind and decrease the costs associated with real-time load/generation imbalance. Wind forecasting can either be centralized or decentralized. With either approach, forecasts are generated for individual wind farms. Centralized forecasting has some advantages:

- the application of a consistent methodology throughout a system allows the forecaster to achieve more consistent results
- an effective identification of approaching weather systems that would affect all wind farms and the ability to warn the ISO of expected changes in wind generation
- the use of data from each wind farm to improve the forecasts at other generation sites.

Wind power forecasting has been researched and is being implemented all over the world. Different types of wind power forecasting methods are being utilized based on the geographical, technical and commercial nature of the different jurisdictions. The Alberta Electric System Operator (AESO) has recently launched a wind power forecasting project to trial different methods and vendors of wind power forecasting tools to determine the best approach to forecasting wind power in Alberta in the future.

Various centralized forecasting tools exist such as the *Prediktor* program in use today in Denmark, Germany and Spain. This tool was developed by Risø National Laboratory, in Denmark, and was based on a previous forecasting model developed by Informatics of Mathematical Modeling (IMM) in

Denmark, together with a local generation company (ELSAM). In the USA, a similar tool "*eWind*" has been developed by TrueWind Solutions LLC and is being used in California. Results of trials in California indicate that the tool is able to predict wind generation with a mean absolute error of 32-35% although the data used for the study is limited. Figure 4-11 illustrates typical forecast error over a period of 48 hours.

For Nova Scotia, wind power generation will be an emerging electricity resource during the next 10 to 20 years. As wind is a variable energy generation source, reasonably accurate forecasting of wind power will be a potentially effective measure to provide NSPI with the information required to better manage the impact of wind power variability on the NSPI grid.

It is recommended that Nova Scotia should also launch a wind power forecasting pilot project when the system has some 200 MW of wind power generation. The actual wind power generation and forecast outputs could be compared and valuable experience could be learned from the pilot project.

4.6 Wind Power Capacity Accreditation

Wind power generation is a non-dispatchable resource as its output depends on the wind conditions at any given instant in time. Therefore, the true capacity contribution of wind plants to power system planning and operation is often a source of great debate and concern among system operators. It has generally been recognized that wind power projects provide some effective load carrying capability and thus contribute to planning reserves but not to day-to-day operating reserves (IEEE publication). The variability and uncertainty of wind generation does typically increase the operating costs of the non-wind portion of a power system.

In some jurisdictions, the wind power contribution to the system firm capacity is calculated by multiplying the wind power rated capacity by its annual capacity factor and then the wind power capacity credit is calculated based on its firm capacity. The capacity factor is the average power output during all the hours over a defined period of time divided by the rated generation capacity.

There are also other ways to calculate the firm capacity of wind power generation. One of them is to calculate the value of the wind power during the highest load period throughout a year, which provides an assessment of the wind resource. This value is called the capacity value of wind power which is a measure of the generation output during critical periods throughout a year, such as those hours when the system load is within 10% or 20% of the annual peak load. Some jurisdictions in North America define capacity value as the capacity factor during those hours of the day when the peak load is likely to occur in the peak months.

The firm capacity of wind plants may serve two major purposes, integrated resource planning and calculation of capacity payment to the developers of wind plants in cases when the jurisdiction offers capacity payments to wind plant operators. When calculating the capacity payment of a new generation project, at least two factors should be considered, the firm capacity of the project and the system firm capacity requirement. The firm capacity requirement is related to both system planning and operation. In some cases, the system load demand less the achievements of DSM programs and other conservation mechanisms could be almost constant over the planning horizon and the existing generation fleet would be adequate to supply the forecast load. As the capacity payment commitment to the existing generation fleet has already been made, the capacity payment to the new generation project would be an additional cost to be borne by the electricity consumers.

The methodology used to calculate the compensation to the operator of a wind plant varies from one jurisdiction to another. The payment compensates wind power producer's costs associated with project development, land lease and right of way, investment loan, equity, profits, operation and maintenance, etc. There are in general three basic cost recovery structures for a wind power plant, which are simply described as follows:

(1) For a wind plant developed and operated by a vertically integrated power utility, all costs of the wind plant may be amalgamated with the costs of the utility's other facilities and are then submitted to its regulatory body for approval. These costs will be recovered through electricity sales based on approved tariffs

(2) For a wind plant developed and operated by an Independent Power Producer (IPP), the revenue received will offset costs incurred. The revenue depends normally on the amount of energy produced and one or more of such factors as the established energy rate from its power purchase agreement (PPA), energy rate determined by market prices, capacity credit rate from the PPA, government grants and renewable incentives, sale of renewable credits and others. Many jurisdictions, including Nova Scotia, compensate IPP wind developers on a specified unit rate for each kilowatt/hour delivered to the system

(3) For a wind plant developed and operated by a power utility, the compensation mechanism to the wind plant could be similar to that in (1), (2), or a combination of the two.

Whether or not capacity payments are offered, there is a need for low temperature options to be installed on machines that expect to provide capacity coincident with peak load in winter peaking systems such as Nova Scotia.

Hatch has developed a prototype Excel based macro model to calculate the capacity factor and capacity value of wind plants. The capacity factors for new wind plants in each of the six zones were calculated based on our projected wind power output profiles. These values were calculated for an entire year, winter season, summer season, the 876 hours (10% of annual hours) with the highest load of the year and the 1,752 hours (20% of annual hours) with the highest load of the year This information is provided in Table 4-2.

It can be seen from this table that the derived wind resource data for Sydney and Canso Strait have a relatively high annual capacity factor of 43.59% while the other four zones have annual capacity factors ranging from some 31% to 35%. It can also be seen that for all six zones, the capacity factors during the winter season including the months from January to April, November and December, are higher that those in the summer season including the months from May to October. This also shows that the wind generation in Nova Scotia tends to coincide with system seasonal load demands as NSPI experiences peak demands during the winter months. In order to see the wind power generation intuitively, Figure 4-12 presents the probability of various wind power output levels for the six zones. It can be seen from this figure that for West zone, there is a probability of some 48% with wind power generation less than 20% of capacity. There is some 30% of time with wind power generation over 60% of capacity.

For the Sydney and Canso Strait zones, there is a 29% probability that wind power generation will be less than 20% of capacity. These two zones have a probability of some 42% that wind power generation will be higher than or equal to 60% of capacity.

One can also find from Table 4-2 that the capacity factors within the 876 hours that have the highest loads of the year are higher or much higher than their corresponding annual values. This means that during system high load demand hours, the wind power plants will generally operate at higher levels than their annual averages. Figure 4-13 to Figure 4-15 show the coincidence of system hourly loads and zonal hourly wind generation for three sets of typical days. The hourly loads used for these figures are excerpted from the forecast 2020 hourly data files. These figures are for five peak demand days (annual hourly peak load day plus two consecutive days at each side), five system light load days (annual hourly minimum load day plus two consecutive days at each side) and five days during the Christmas Holiday season.

The overall capacity factors for the proposed levels of wind power integration were also calculated against the 2020 load profile and these are presented in Table 4-3. The wind power integration levels include total capacities of 311, 581, 781 and 981 MW.

It is important to note that the capacity factors calculated for the high load hours as presented in Table 4-2 and Table 4-3 are based on the system load profile only, i.e. without accounting for the impact of wind power integration on system load. It is noted that, the system net load profile (load minus wind power generation) may change as more wind power is integrated into the system. It is suggested these capacity factors should be recalculated based on net load profile for each integration level of wind power (such as increments of 100 MW or 200 MW) if they will be used as the measurement for wind power capacity payment.

As the capacity values/factors presented in this report were calculated based on the wind measured from monitor towers and only a limited number of monitor towers were available for analysis, it is suggested the capacity value/factor of a future wind power plant be calculated based on its actual generation. The actual capacity value/factor may vary from one location to another location, one type of WTG to another type of WTG, one zone to another zone, one year to another year etc.

4.7 Future Directions for Wind Generation Technology

Foretelling the future with regards to technology development is speculative in nature. This section takes the approach of highlighting today's challenges with existing technology to predict where future developments are most likely to occur. Such an approach is not able to foresee any fundamentally different technological development that could potentially revolutionize the wind power industry, but primarily looks at evolutionary innovations.

On the electrical side, the NERC reliability standards place various requirements on electric utilities and these generally result in the need for each generation source to contribute to the stability of the grid, both steady state and transient (fault) conditions, while not causing degradation to the grid.

The characteristics of wind generators relevant to impacts on a power system could include voltage flicker, power factor/voltage control, low voltage ride through and harmonics.

(1) Voltage Flicker (momentary decrease/increase in grid voltage, on a one time or repetitive basis) – the voltage flicker requirements are well defined in the applicable IEEE standards and other documents, this is not too much of a concern with today's wind generator technology. This concern developed when the turbines were basically induction generators. Some machines were started as motors under marginal wind conditions, then switched to generation mode when up to speed. This causes a motor starting inrush and a surge when the machine goes into generation. Even with induction machines that can be brought up to some speed near system frequency, then the breaker closed, there can be either an inrush if the speed is less than system frequency, or a "bump" sending power out into the system if the speed is above system frequency. With today's technology, virtually all large machines are not simple induction generators, and are, in effect, synchronized before connecting to the grid resulting in little or no flicker effect.

(2) Power Factor/Voltage Control – these are really two different modes of operation. In voltage control mode, the amount of VARS produced varies to maintain a constant voltage, while in power factor mode, the voltage varies to maintain a constant power factor. Regardless, as far as the network is concerned, for a system to remain stable electrically, the MW produced in the system must equal the MW required by the load (frequency stability) and the MVAR produced in the system have to equal the MVAR required by the load (voltage stability). The generator connected to a grid is normally required to contribute to the

MVAR supply, i.e. contribute to voltage stability. The requirement is usually stated as having the ability to operate through a range of leading and lagging power factors.

To vary power factor of a generator directly, one must have a means of controlling the generator excitation to vary the generator output voltage. However other methods are available to achieve the same objective, i.e. through a static inverter, or external switched power factor correction devices.

Actually, the statement that the generator is required to maintain a given power factor is not quite correct. Although varying the power factor, in effect, varies the VAR generation, the amount of VARS provided for a constant power factor, varies with the amount of generation, i.e. the power factor is a ratio. Some provinces, for example, Ontario, state that the power factor requirement of the connected generation source must provide the equivalent amount of VARS as a hydraulic synchronous generator. Since a hydraulic synchronous generator can produce VARS with zero real power output, this can also be interpreted as a requirement for a wind plant. It is very difficult to achieve this without the use of external auxiliary equipment, that is, the use of external reactors and capacitors.

The Enercon, AWE and Vensys machines currently installed in Nova Scotia have the capability to produce VARS with zero real power output providing the wind is above a minimum value. Wind generators that use Double-Fed Induction Generator technology (including GE and Vestas equipment) also have this capability.

(3) Low Voltage Ride Through – the ride through characteristics are well defined by the applicable standards. When a fault occurs on the system, it is necessary to maintain a certain amount of fault current for the protective devices to operate. Also, when the fault clears, a certain amount of generation must remain on line to restore the system. When the amount of wind generation on the grid system was not significant, it was not a concern to the grid operator if the wind generator tripped off line during faults, and was not immediately available after the fault cleared. In fact, in some extreme cases, it could take several hours or longer time to restore the wind generation.

However, as the amount of wind generation increased on the grid systems, the grid operators now expect the generation to remain on line contributing fault current through the duration of an external fault, and generation be immediately available to assist in system recovery should a fault occur. This is given by the low voltage ride through criteria, that is, the voltage, measured at the machine, above which the generation must remain on line for a specified time period. Some system operators may require that a new generator have a zero voltage ride through if it will be connected to a 50 kV or higher voltage line. There are some wind generators that can presently meet a zero voltage ride through criteria, others require certain modifications, normally to the control and protection system.

(4) Harmonics -- harmonics cause distorted sinusoidal waveforms and excessive losses in an electrical system. The presence of harmonics is becoming a real concern. Any generation using an inverter, full or partial, has a significant harmonic content in the output waveform. While off hand it would appear that the harmonic spectrum of each individual generator conforms to the relevant IEEE standard 519, the generation waveform at the point of interconnection may not. This is due to a variety of factors, most notable is the increasing requirement (due to visual environmental concerns) to provide electrical connection between the turbines through the use of underground HV cables which can contribute significant capacitance to the electrical system. This, coupled with the use of external reactors and capacitors necessary to provide the required VARS, can create electrical resonant conditions which can substantially increase the magnitude of the harmonics. In

addition, since the harmonic content of the individual generator waveform can vary both in frequency and magnitude, with it's output, it is difficult to analyze the system theoretically. There are at least two wind power projects in the Province of Quebec that required installation of multi-pole filter banks to meet the IEEE 519 harmonic requirements at the point of interconnection. It is likely that future development will include machines with built in harmonic filtering at each generator.

Future technological developments for wind turbine generators will need to be geared towards addressing these electrical system requirements. As the overall level of wind power penetration and the size of individual wind farms increases, higher expectations will be placed on these wind farms as significant power plants with responsibility for contribution to the grid system stability.

For operation in northern climates turbine blade icing is not only a concern of public safety (ice shedding), but also one of electric system operation. For example, there was an instance in 2007 in Ontario when a significant sized wind farm started to experience icing, one unit went off line, then within a ½ hour or so, all the units tripped off line, a loss of approximately 100 MW of generation. This caused a problem with the lack of reserve capacity on the system at the time, and the need to bring standby generation on line within a short period of time. As a consequence of this event, the Ontario independent system operator now requires early indication of pending icing, prior to shutdown of a turbine. Vibration detectors do not work, as they provide indication too late. "Forecasting" methods are not generally accepted as they do not reflect the actual conditions being encountered at site. What some manufacturers have done, to conform to the Ontario requirements is to use a model simulation within their individual control units (at each turbine) that examines the theoretical output of the turbine based on measured wind speed and the actual output based on real time power measurements. It is assumed that a loss of power in real time compared to the theoretical output indicates a degradation of the turbine blade, which would result from ice build up modifying the blade profile. Should the actual output be below the theoretical output, then an alarm contact is initiated indicating pending icing conditions. This is carried through into the SCADA system and passed on to the system operator before the actual shutdown occurs allowing the system operator to place more generation on standby. Transenergie in Quebec now imposes similar requirements. Further technology developments will have to deal with the controlled shut down under icing conditions.

Mechanical innovation may be primarily directed at alleviating the fluctuating loads on the blades and drive train that has in the past lead to fatigue failures with associated high costs for replacement of components that necessitate the use of large installation cranes. Into this realm play technology advancements on blade pitch control, hydro-mechanical torque converters to reduce the stiffness of the power train, directly coupled generators that increase overall reliability by omitting the need for a gearbox or a power train that splits the low speed prime mover into multiple generators and enables onboard hoists to handle most components. Likely, different manufacturers will pursue different avenues to the same end of reducing load fluctuations or their consequences and will protect their technology through patent rights. Market competition which has a strong non-technical element will decide on the most successful technology to emerge.

A related stream of innovation is directed at the ice formation and resulting imbalanced rotor loads and electricity production loss during icing events. Here innovative coatings, forced (resistive heaters) and natural (dark coatings) blade heating as well as mechanical means of deflection and inflation are being investigated to control blade icing.

Higher aerodynamic blade performance and reduction of high wind hysteresis are two more areas of development with slow and steady progress that improve the electricity production yield.

Structural innovation predominantly addresses the desire for greater hub heights that yield higher electricity generation due to wind shear. Use of alternate materials from the traditional steel tubular tower – predominantly concrete, but even a timber design is on the published record – as well as less expensive erection technologies such as self erecting steel towers as well as slip formed or pre-cast concrete towers have merit for future development.

With higher hub heights structurally feasible the turbine erection methodology will deserve a close look towards innovation. Already today main erection cranes for the wind industry are among the largest cranes available for any industry. With higher lifts cargo lifters or sky cranes may become economically competitive.

Innovation in the understanding of the wind resource is geared at better modelling approaches for design optimization as well as wind forecasting tools to make wind power into a more predictable source of electricity generation that approaches the reliability of dispatchable forms of generation.

Table 4-1: Zonal Wind Power Capacity

			Zone						
			West	Valley	Truro	Pictou	Canso Strait	Sydney	Total
Existing Installation (2007)		**Name Plate**	31.2	1.9	7.5	2.7	0.9	16.3	61
		Maximum *	27.5	1.7	6.6	2.4	0.8	14.1	53
						All Three Cases			
Total Installation by 2010									
	Option 1	**Name Plate**	31.2	41.9	57.5	62.7	100.9	16.3	311
		Maximum *	27.5	36.9	50.7	55.2	87.1	14.1	272
	Option 2	**Name Plate**	31.2	41.9	87.5	122.7	10.9	16.3	311
		Maximum *	27.5	36.9	77.1	108.1	9.4	14.1	273
Total Installation by 2013		**Name Plate**	61.2	111.9	117.5	142.7	110.9	36.3	581
		Maximum *	53.9	98.6	103.5	125.7	95.7	31.3	509
						Base Plan			
Total Installation by 2020		**Name Plate**	61.2	111.9	117.5	142.7	110.9	36.3	581
		Maximum *	53.9	98.6	103.5	125.7	95.7	31.3	509
						Alternative 1 Plan			
Total Installation by 2020									
	Option 1	**Name Plate**	61.2	111.9	117.5	142.7	310.9	36.3	781
		Maximum *	53.9	98.6	103.5	125.7	268.4	31.3	682
	Option 2	**Name Plate**	161.2	161.9	167.5	142.7	110.9	36.3	781
		Maximum *	142.0	142.7	147.6	125.7	95.7	31.3	685
						Alternative 2 Plan			
Total Installation by 2020									
	Option 1	**Name Plate**	161.2	111.9	217.5	142.7	310.9	36.3	981
		Maximum *	142.0	98.6	191.7	125.7	268.4	31.3	858
	Option 2	**Name Plate**	161.2	161.9	167.5	142.7	310.9	36.3	981
		Maximum *	142.0	142.7	147.6	125.7	268.4	31.3	858

Note: * indicates the maximum output capacity to the system after taking into consideration loss assumptions

Table 4-2: Capacity Factor of Zonal Wind Plants

	Zone			
Month	**West**	**Valley**	**Truro Pictou**	**Canso Strait Sydney**
January	42.07	34.82	34.80	46.89
February	52.31	49.29	38.62	43.72
March	39.01	40.35	39.72	43.72
April	28.62	34.83	24.89	45.72
May	23.69	36.88	20.68	30.15
June	24.83	22.63	30.01	39.61
July	16.86	17.39	34.85	44.77
August	14.08	14.70	17.98	44.32
September	29.67	28.63	33.06	41.34
October	34.33	37.17	33.36	47.07
November	45.86	46.06	35.39	45.48
December	50.52	53.51	39.46	50.21
Annual	**33.35**	**34.59**	**31.86**	**43.59**
Seasonal				
Winter (1)	42.98	43.07	35.49	46.00
Summer (2)	23.87	26.24	28.29	41.22
10% Highest Load Hours (3)				
Annual	46.89	44.08	37.73	46.80
Winter	45.07	39.18	37.07	48.23
Summer	25.54	33.29	24.32	37.83
20% Highest Load Hours (4)				
Annual	46.33	44.10	37.07	45.69
Winter	47.00	44.04	37.77	46.80
Summer	25.07	29.67	28.10	37.39

Note:
(1) -- The Winter season includes months from January to April, November and December
(2) -- The Summer season includes all months from May to October
(3) -- 10% highest load hours within the period
(4) -- 20% highest load hours within the period

Table 4-3: Capacity Factor of Proposed Levels of Wind Power Integration

	311 MW Wind (1)	311 MW Wind (2)	581 MW Wind (3)	781 MW Wind (4)	781 MW Wind (5)	981 MW Wind (6)	981 MW Wind (7)
Month							
January	40.09	36.59	38.63	40.75	38.58	40.28	40.28
February	43.36	41.89	43.42	43.49	44.62	43.90	44.44
March	41.24	40.08	40.78	41.53	40.46	41.09	41.12
April	34.47	28.43	32.48	35.87	31.65	34.01	34.52
May	26.74	24.00	26.52	27.45	26.45	26.38	27.20
June	32.12	29.34	30.48	32.82	29.22	31.72	31.34
July	34.43	31.56	32.10	35.35	29.38	33.41	32.52
August	27.09	19.45	23.62	28.92	21.46	26.29	26.12
September	35.25	32.85	33.95	35.84	33.00	34.93	34.70
October	39.15	35.17	37.67	40.08	36.94	38.81	39.00
November	41.69	38.77	41.11	42.23	41.67	41.90	42.45
December	46.52	43.41	46.06	47.12	46.69	46.69	47.40
Annual	**36.80**	**33.40**	**35.52**	**37.58**	**34.94**	**36.57**	**36.71**
Seasonal							
Winter	41.23	38.18	40.40	41.84	40.59	41.31	41.69
Summer	32.45	28.70	30.71	33.40	29.39	31.91	31.80
10% Highest Load Hours							
Annual	42.93	40.30	42.22	43.39	42.65	43.17	43.50
Winter	42.37	39.14	41.15	42.96	41.27	42.58	42.69
Summer	30.75	26.84	29.60	31.71	28.98	30.33	30.79
20% Highest Load Hours							
Annual	42.20	39.71	41.59	42.64	42.07	42.45	42.81
Winter	42.95	40.33	42.24	43.41	42.68	43.20	43.52
Summer	31.51	28.82	30.44	32.22	29.55	31.07	31.15

Note:

(1) -- A total of 250 MW new wind generation capacity is allocated to Valley (40 MW), Truro (50 MW), Pictou (60 MW) and Canso Strait (100 MW).

(2) -- A total of 250 MW new wind generation capacity is allocated to Valley (40 MW), Truro (80 MW), Pictou (120 MW) and Canso Strait (10 MW).

(3) -- A total of 520 MW new wind generation capacity is allocated to West (30 MW), Valley (110 MW), Truro (110 MW), Pictou (140 MW), Canso Strait (110 MW) and Sydney (20 MW).

(4) -- A total of 720 MW new wind generation capacity is allocated to West (30 MW), Valley (110 MW), Truro (110 MW), Pictou (140 MW), Canso Strait (310 MW) and Sydney (20 MW).

(5) -- A total of 720 MW new wind generation capacity is allocated to West (130 MW), Valley (160 MW), Truro (160 MW), Pictou (140 MW), Canso Strait (110 MW) and Sydney (20 MW).

(6) -- A total of 920 MW new wind generation capacity is allocated to West (130 MW), Valley (110 MW), Truro (210 MW), Pictou (140 MW), Canso Strait (310 MW) and Sydney (20 MW).

(7) -- A total of 920 MW new wind generation capacity is allocated to West (130 MW), Valley (160 MW), Truro (160 MW), Pictou (140 MW), Canso Strait (310 MW) and Sydney (20 MW).

Figure 4-1: Typical Meteorological Mast Tower Configuration

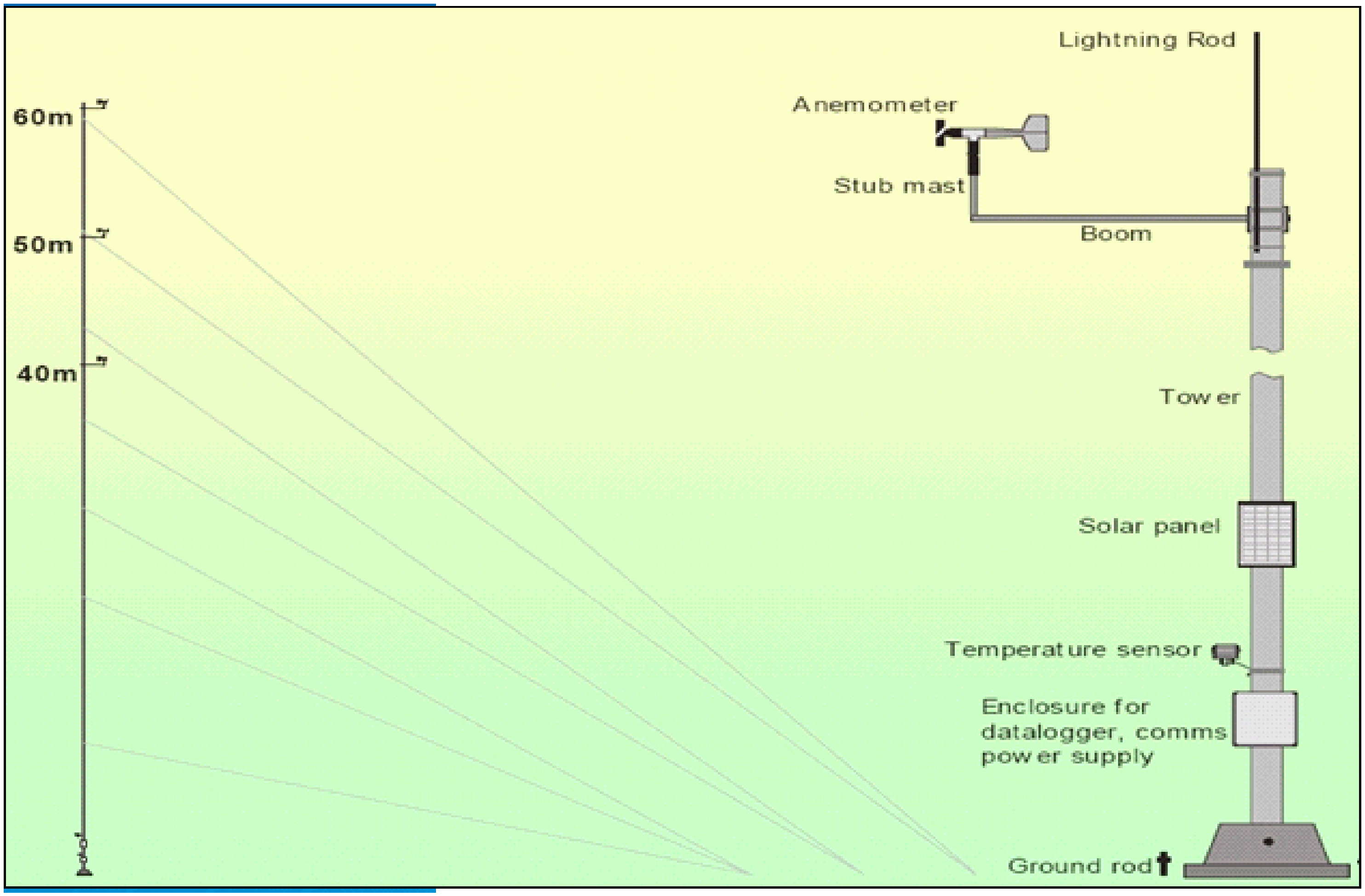


Figure 4-2: Wind Speed Time Series Illustrating Temporal Gap

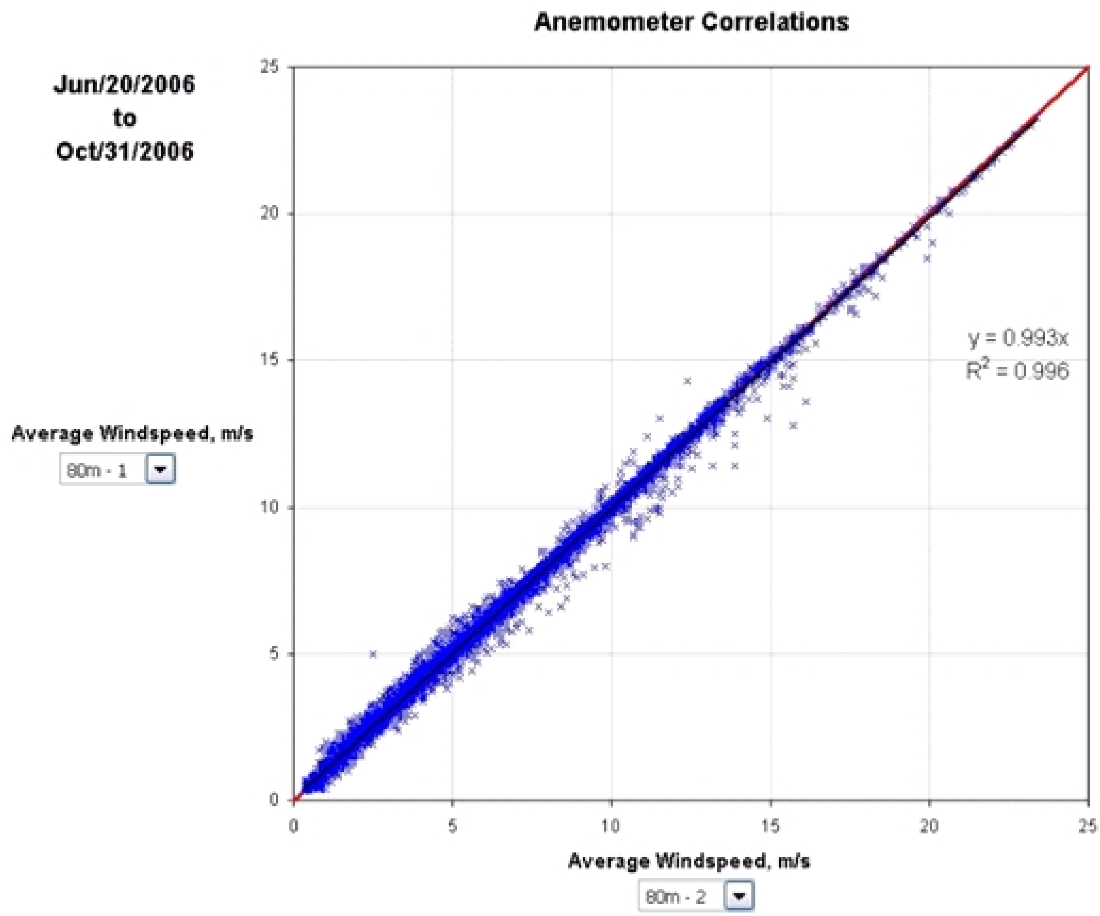


Figure 4-3: Typical Anemometer Correlation Plot

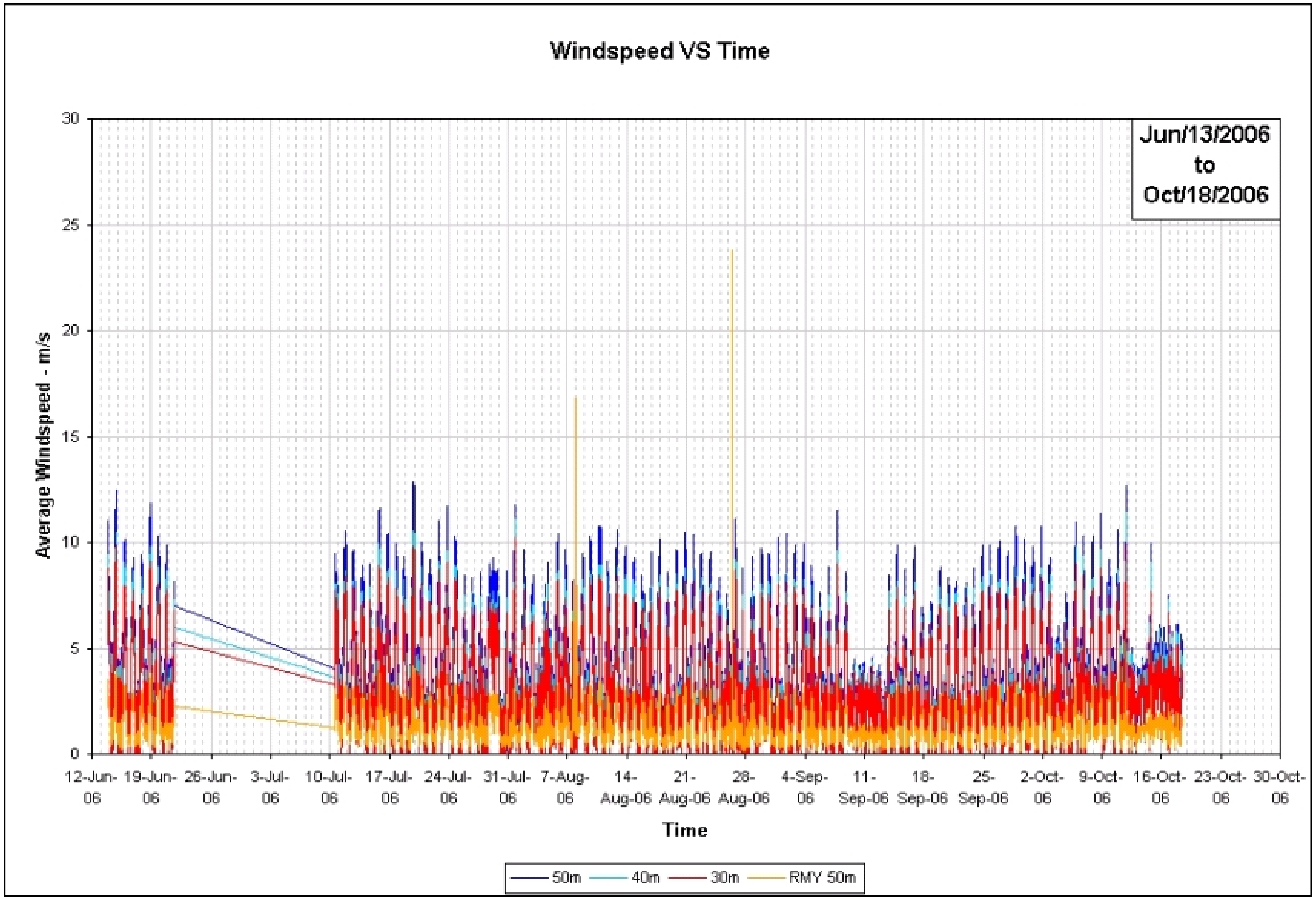


Figure 4-4: Typical Wind Shear Profile

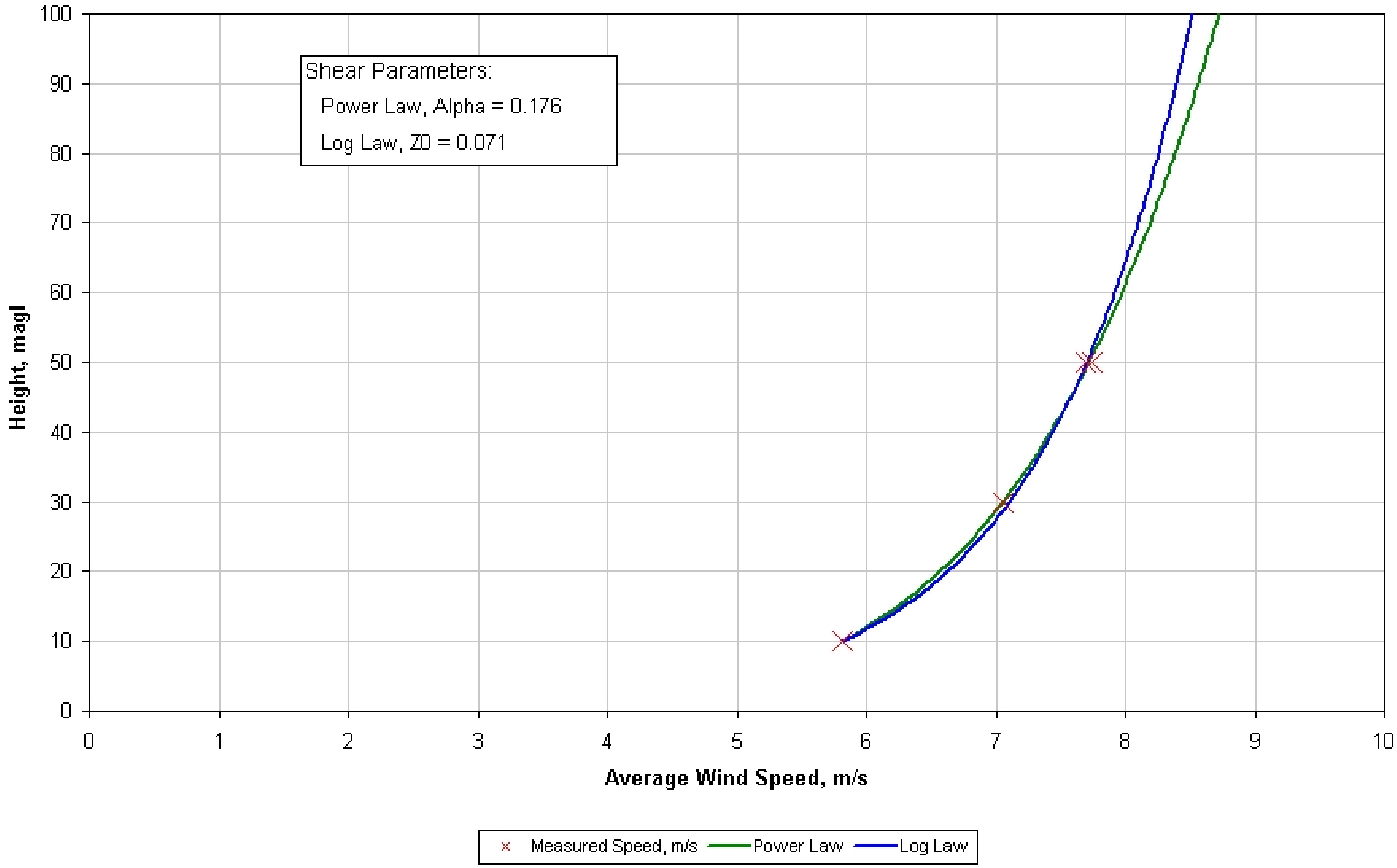


Figure 4-5: Typical Wind Speed Frequency Histogram and Weibull Probability Distribution

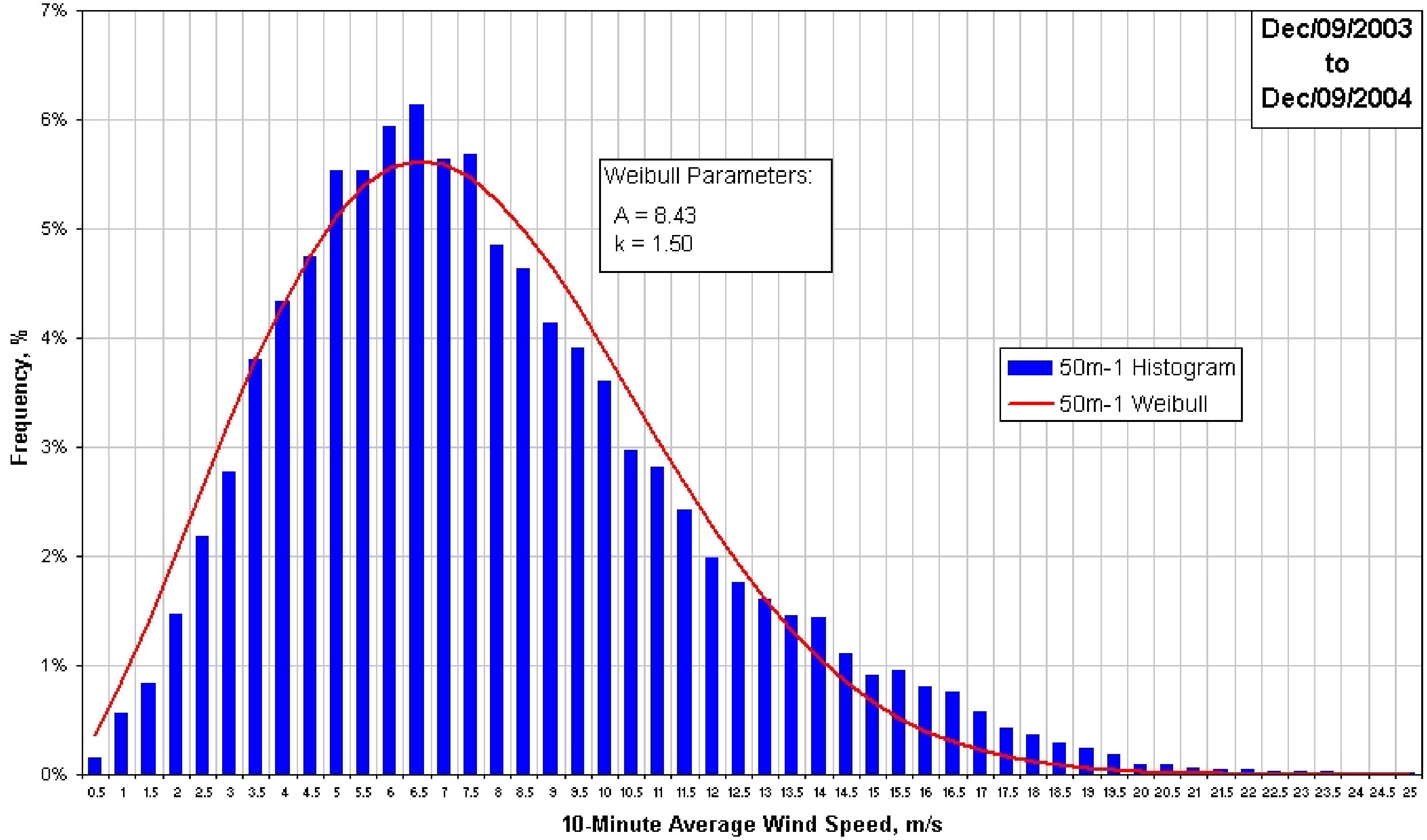


Figure 4-6: Sydney Airport Long-term Reference Data

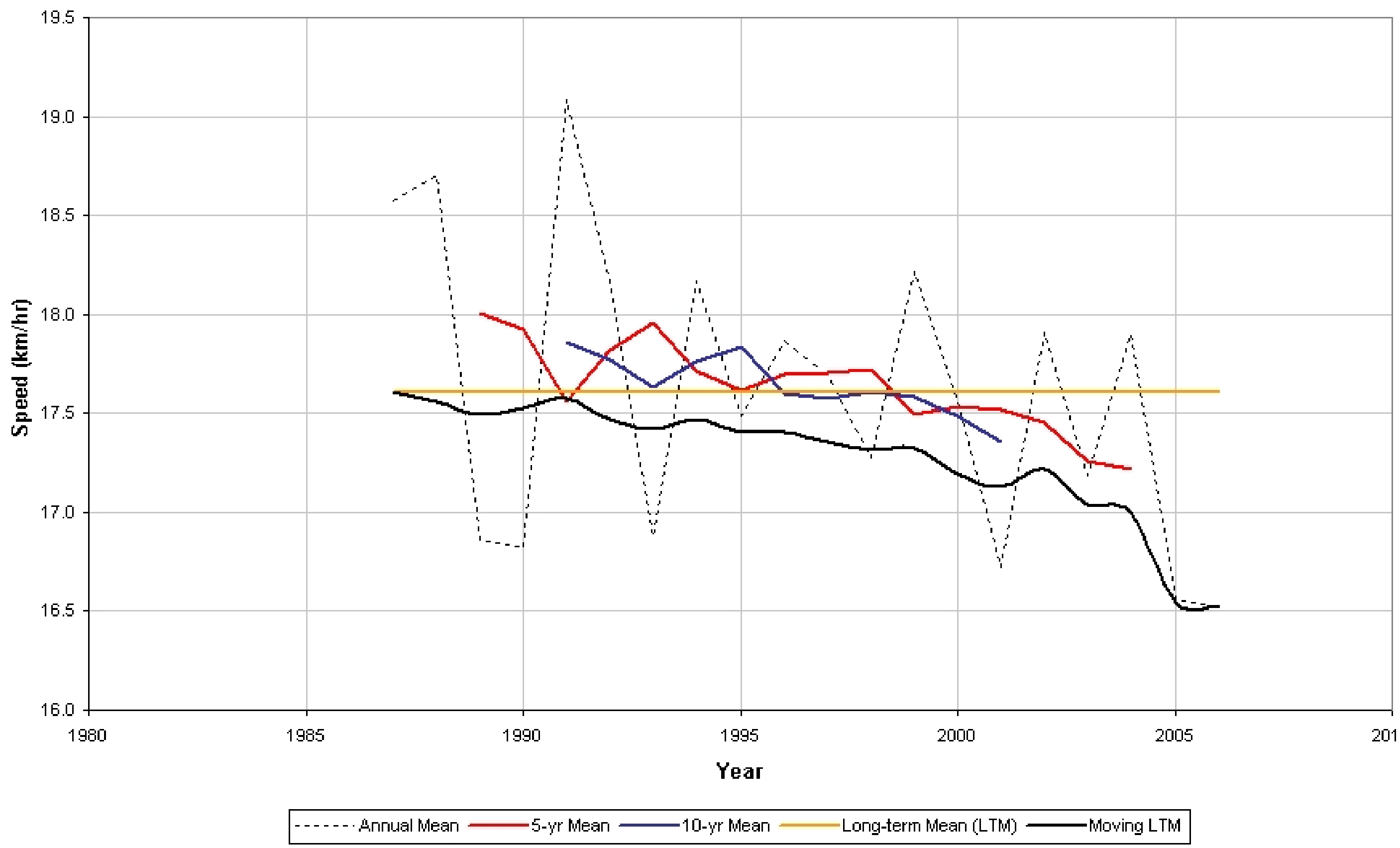


Figure 4-7: Yarmouth Airport Long-term Reference Data

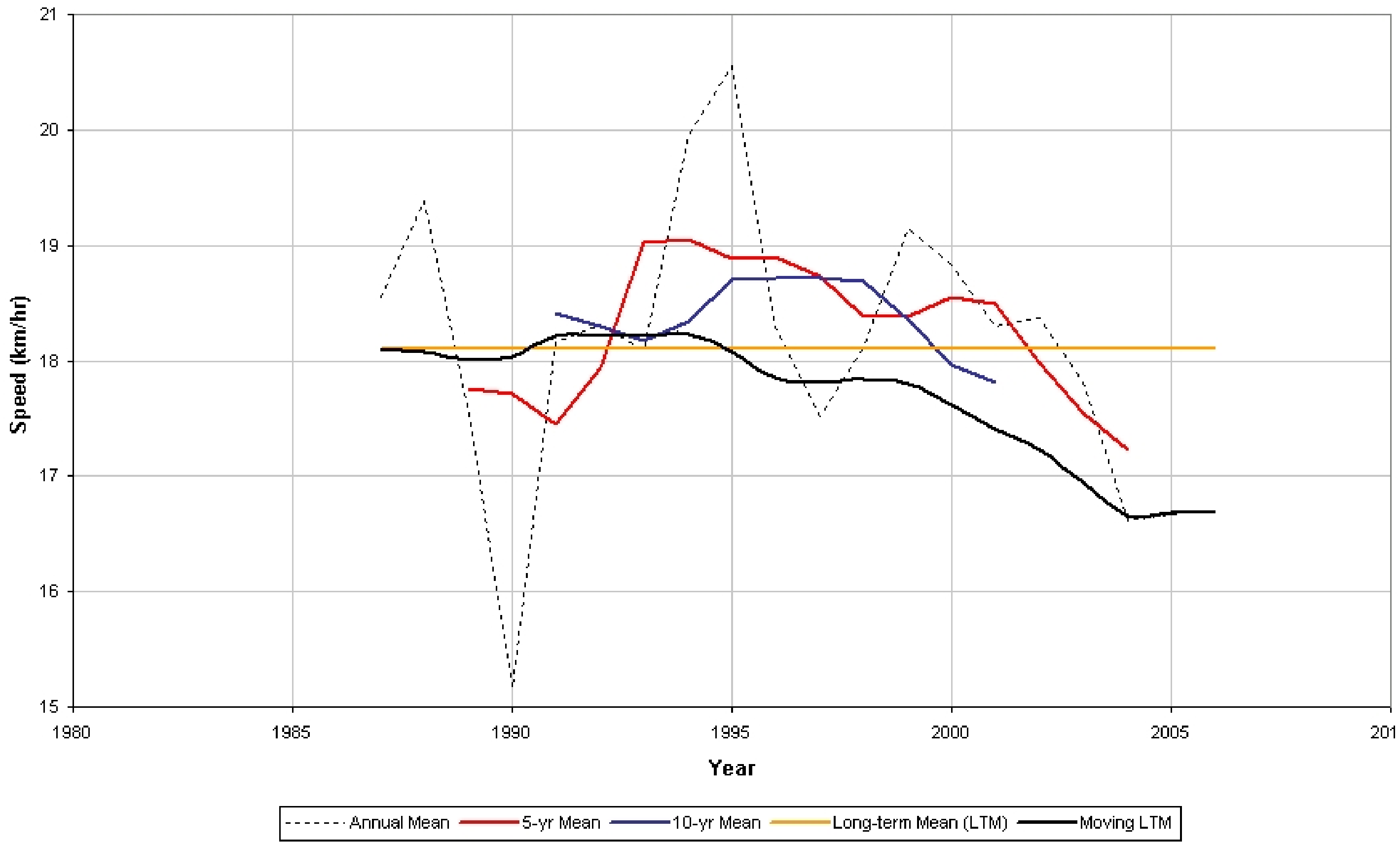


Figure 4-8: Sydney Region Diurnal Trends

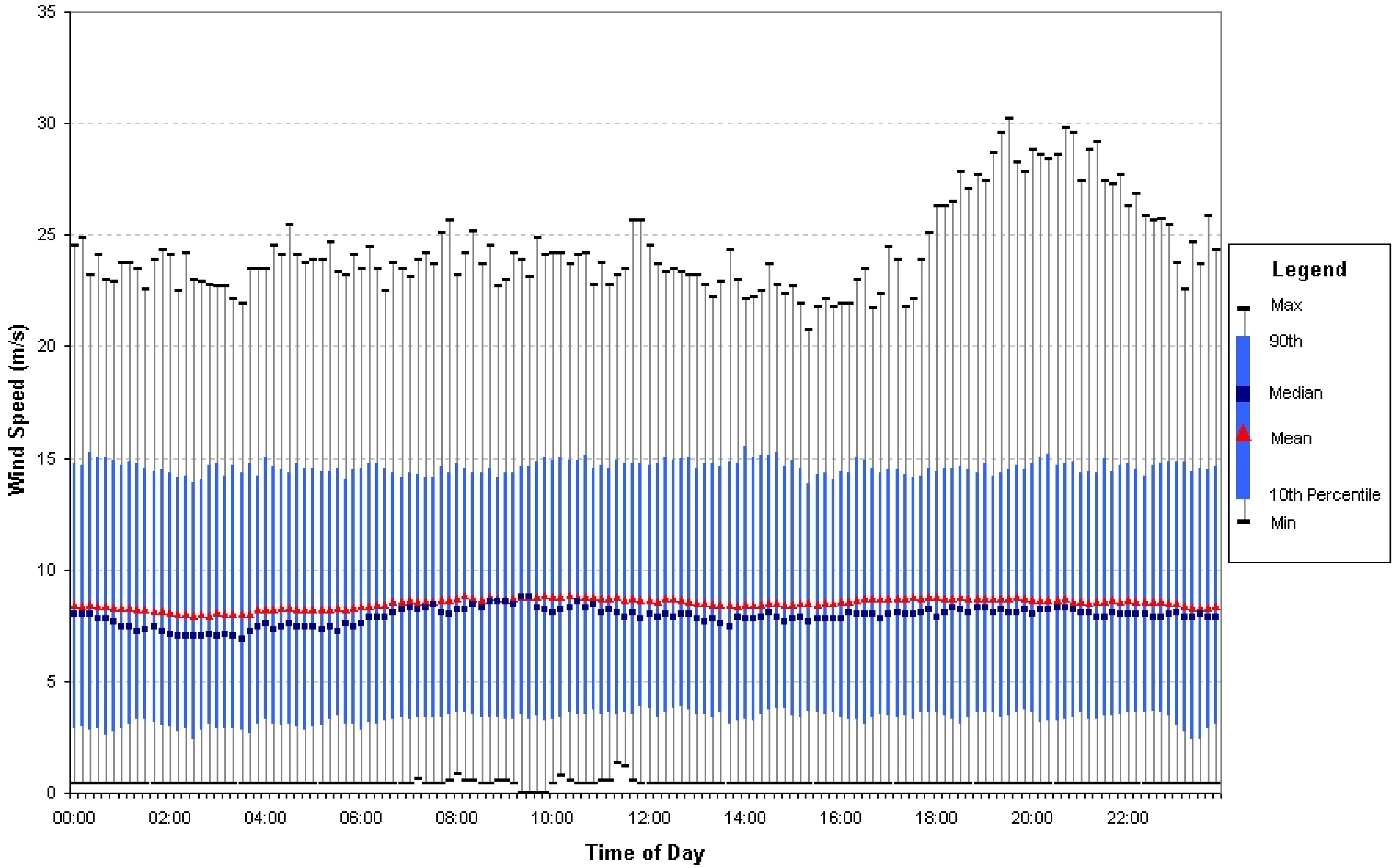


Figure 4-9: Valley Region Diurnal Trends

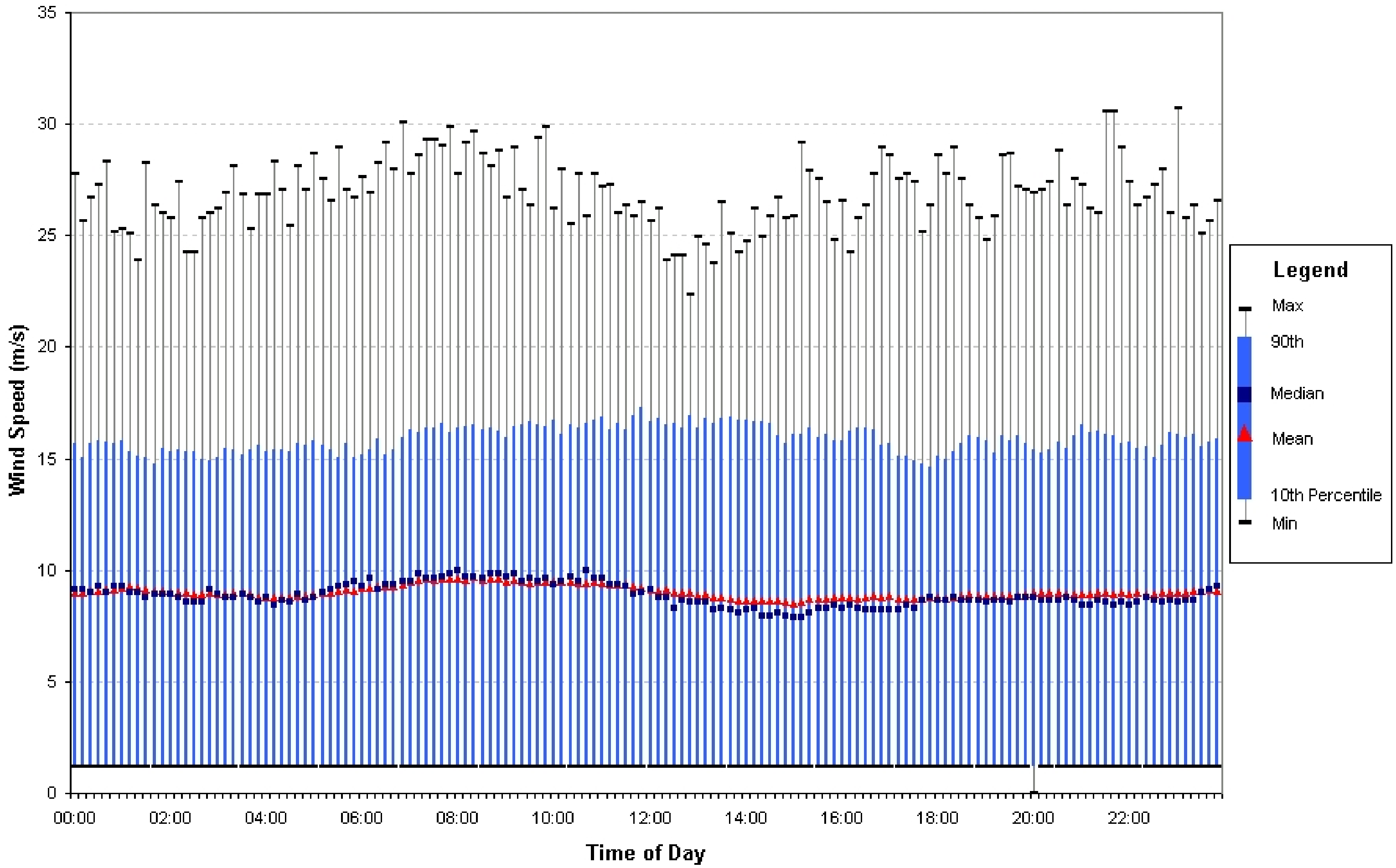


Figure 4-10: Wind Turbine-Generator Power Curves

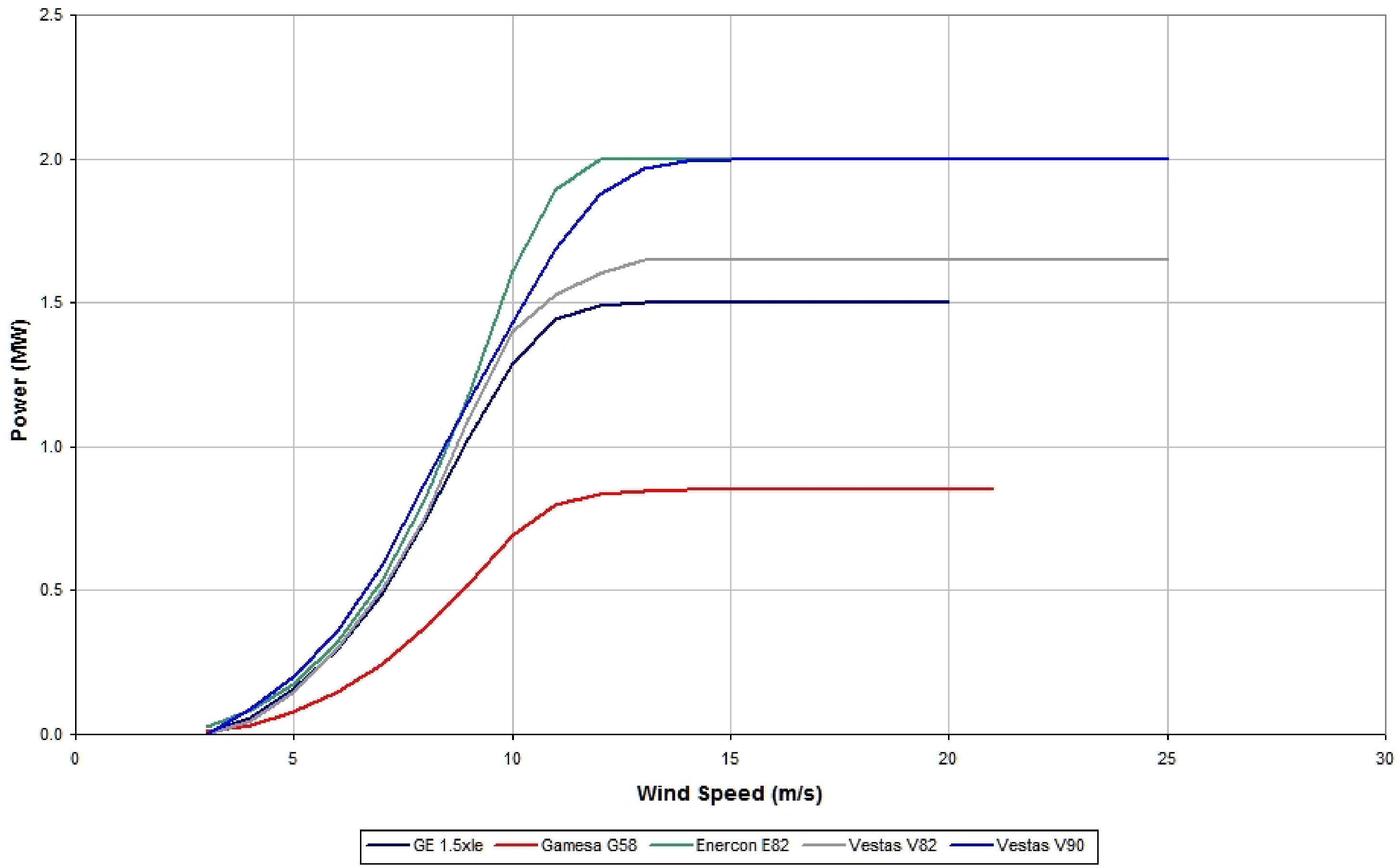


Figure 4-11: Typical Wind Generation Forecast Error

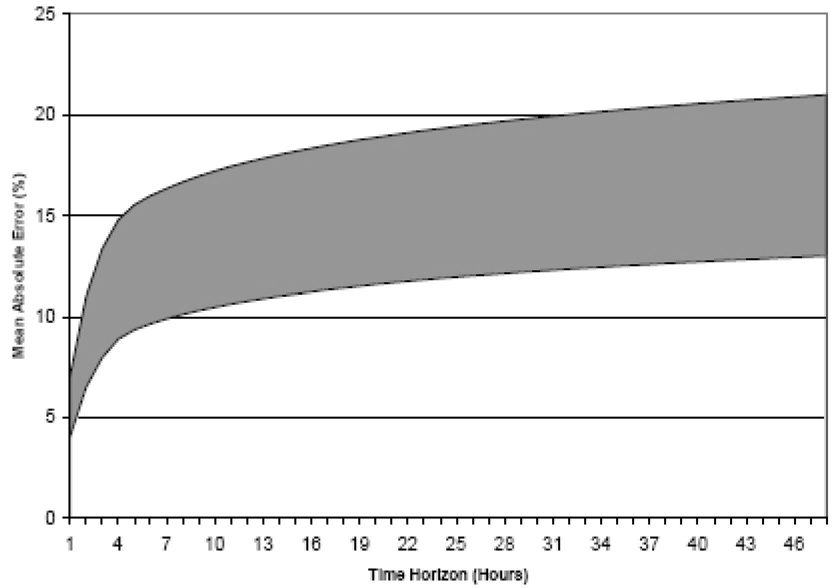


Figure 4-12: Probability of Various Wind Power Generation Levels

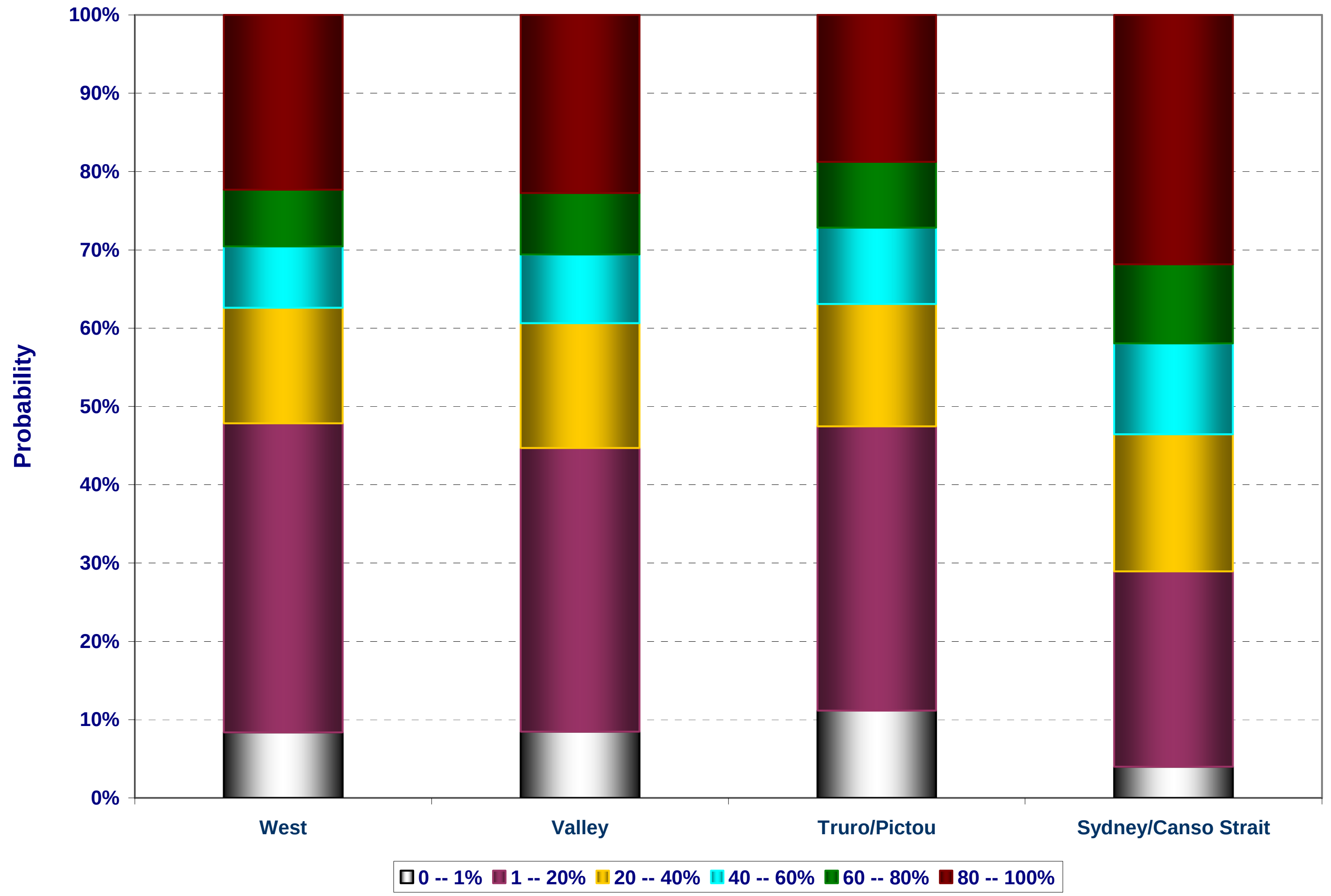


Figure 4-13: Coincidence of System Load and Wind Power During Peak Load Days

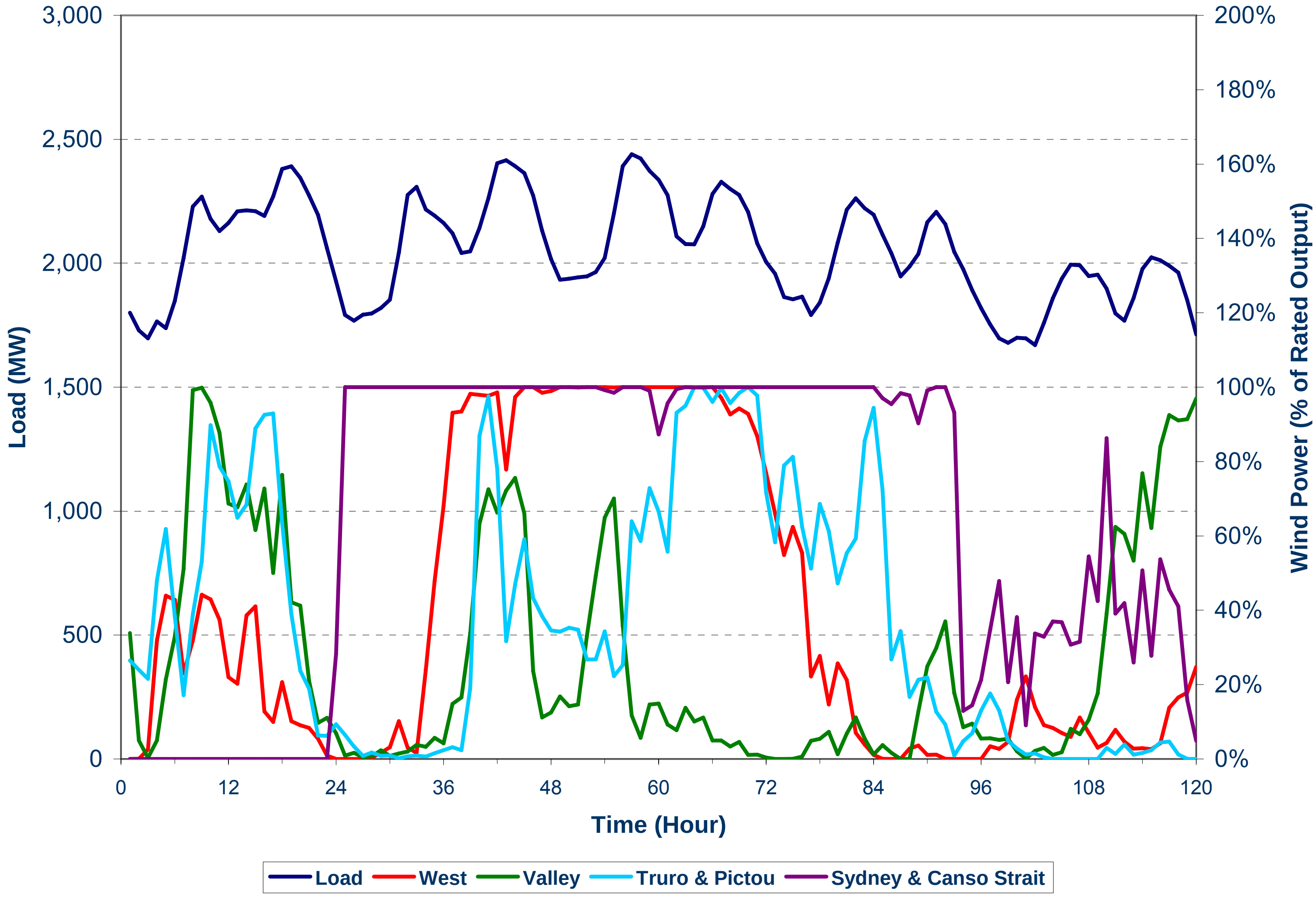


Figure 4-14: Coincidence of System Load and Wind Power During Light Load Days

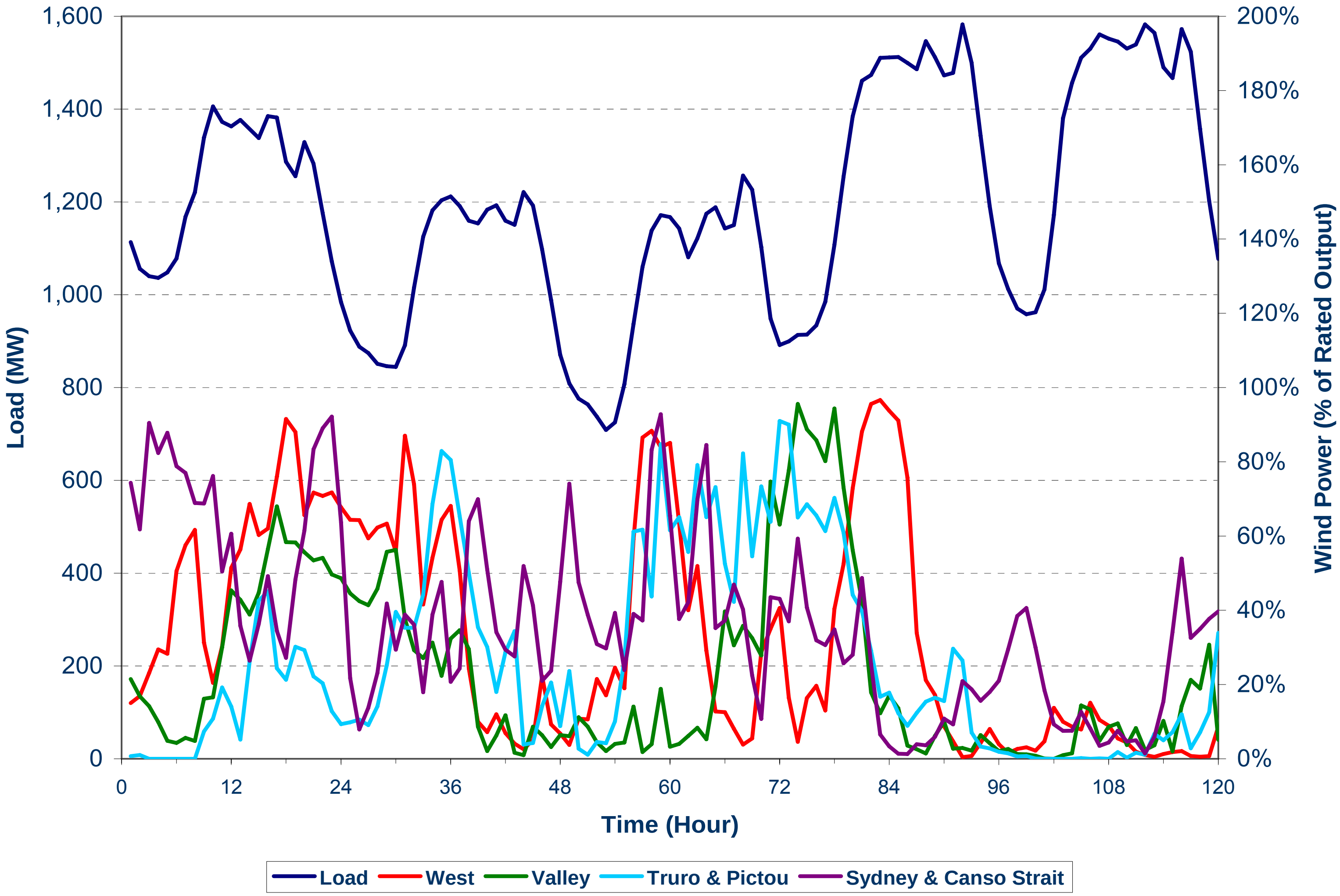
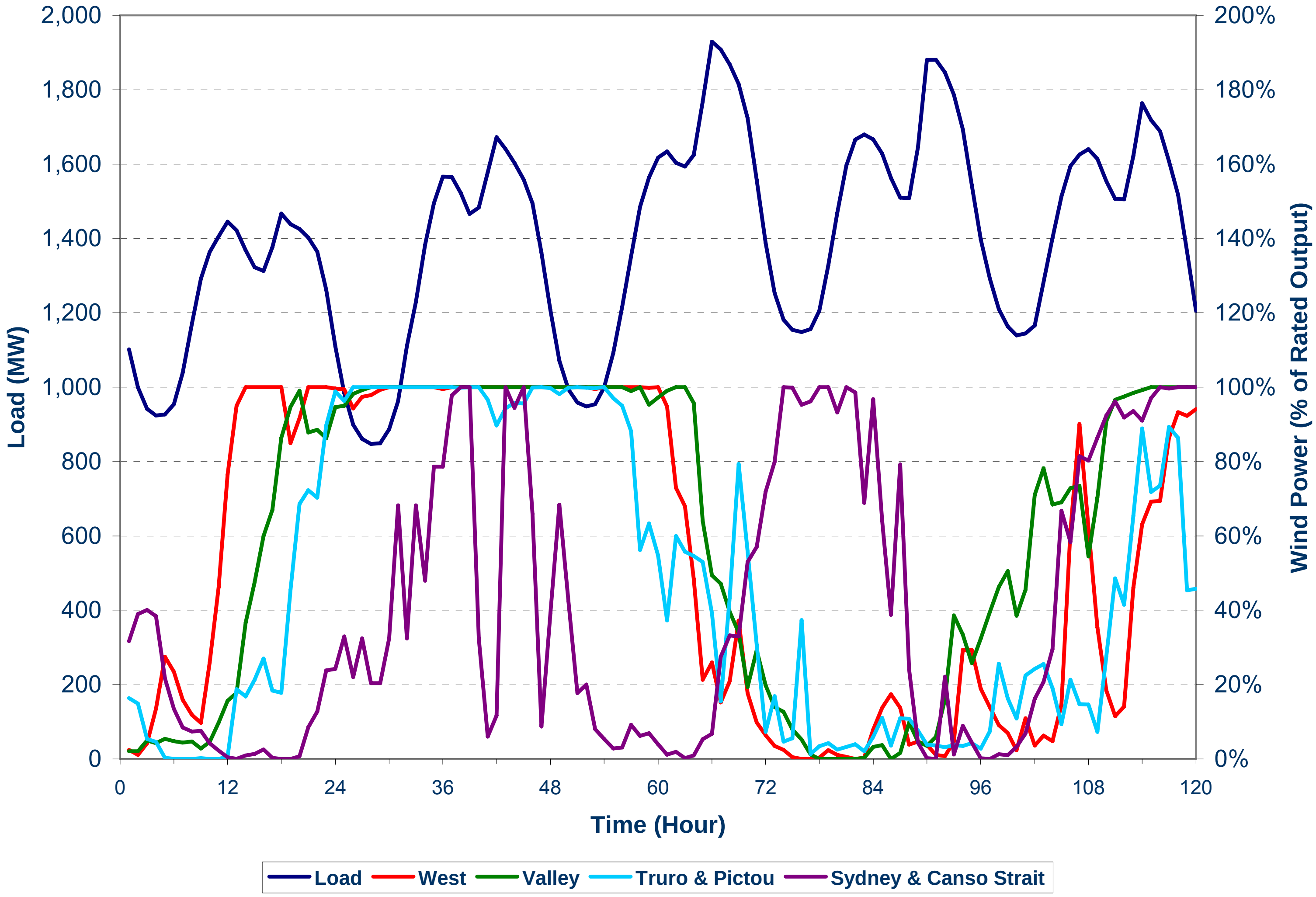


Figure 4-15: Coincidence of System Load and Wind Power During Christmas Holiday Season



5. System Dispatch Modeling

5.1 Introduction

This section describes the results of the modeling carried out to simulate the dispatch of the system under the assumed wind capacity installation cases.

The primary purposes of the *Vista* simulation of NSPI generation system dispatch are as follows:

(1) Examining the dispatching capability of the NSPI generation fleet

(2) Projecting the energy output of each generating unit/plant

(3) Projecting the ancillary services including spinning reserve and load following to be provided by each generating unit/plant

(4) Computing the fuel consumptions and costs of thermal generating units/plants

(5) Estimating potential interruptions to interruptible loads or firm load

(6) Examining the congestion of major intra-province transmission circuits.

After consultation with NSPI, it was decided that a two-hour interval step would be used in the *Vista* simulations. It is considered that the differences in results between those resulting from one hour and two hour interval steps are not a material concern for the purposes of this initial study.

The *Vista* model was implemented for NSPI's hydro plants several years ago. For this study Hatch updated the input data and enhanced the model to accommodate thermal unit operational characteristics.

5.2 General Modeling Approach

The *Vista* model is an optimization tool used by operators to dispatch units on an hourly basis. The model also is used quite frequently as a planning tool to simulate system operations over a one year or multi-year period. The model uses detailed mathematical equations describing thermal and hydro generation unit characteristics, spill and river reach hydraulics and reservoir operations to determine hourly generation dispatch patterns over a week. The required input data to the model include hourly load demands, market opportunity, fuel prices, reserve requirements, generating unit outage schedules and bus-to-bus transmission capabilities, etc. The objective of the model is to minimize system generation costs over a week. Essentially the model dispatches generation to meet load requirements in such a manner as to abide by constraints defined and minimize costs by running available hydro and thermal units optimally. Constraints on the system include hydraulic, operational and reserve constraint sets. The operating cost structure within the Nova Scotia system is a function of fuel prices and the presumed penalty for interrupted load. The model thereby uses the generation from wind, run-of-hydro and biomass first to meet the load demands. Additional energy required to meet the load demands is produced by the thermal plants available based on the cost of fuel and the dispatchable hydro plants with available energy. Generation units/plants must not only meet the load demands but also meet the ancillary service requirements including spinning, AGC and load following. Non spinning reserve requirements could be achieved by quick start units and interruptible loads.

5.2.1 Modeling Time Step

Investigations into the most appropriate modeling time step for the NSPI application was undertaken early in the project. The *Vista* model is an hourly model and initial tests indicated that, given the complexity of the Nova Scotia system and the level of operational details included in the model, the one-hour time step would result in unmanageable computation time for analysis over a period of one year. After consultation with NSPI, a time step of two hours was ultimately selected to carry out the analysis. Another time blocking of four hours was also investigated but deemed to be too large to capture operations specifically at Wreck Cove hydro plant.

It is important to mention that in the two-hour time step, all inputs which are provided in an hourly base were averaged for every two hours. This means that the input values for Hours 1 and 2 are an average so that the model's outputs show the two hours with identical results.

It is considered that the differences in results between those resulting from one hour and two hour interval steps are not a material concern for the purposes of this initial study.

5.2.2 Modeling Scenarios

As described in Section 3, three generation development plans were developed to include both planned additions/upgrades plus potential wind power integration. In order to evaluate the impact of different levels of wind power integration on system dispatch, Hatch carried out *Vista* simulation for the cases presented in Table 5-1.

Table 5-1: Defined *Vista* Simulation Cases

Case No.	Wind Power MW	Year
1	61	2008
2	61	2010
3	311 - Option 1	2010
4	311 - Option 2	2010
5	61	2013
6	581	2013
7	61	2020
8	311 - Option 1	2020
9	311 - Option 2	2020
10	581	2020
11	781 - Option 1	2020
12	781 - Option 2	2020
13	981 - Option 1	2020
14	981 - Option 2	2020

5.3 Description of *Vista* Model

Optimization of system operations is driven to minimize overall costs under the governing physical and load constraints of the system. System constraints for application on this study include:

(1) Reservoir physical and operational limits

(2) Unit characteristics and operational limits

(3) Historical inflow sequences

(4) Channel lag and route characteristics

(5) River flow constraints

(6) Firm contracts

(7) Transmission constraints including transmission capability of tie-lines

(8) Maintenance schedules of generating units

(9) Reserves.

It is important to note that the *Vista* simulation carried out in this study is based on perfect information on the future and output results are based on deterministic analysis. For example, in a weekly analysis, the model carries out its simulation based on exact information over the week on hourly load demand, wind power generation, water inflow, generating unit and transmission line availability, fuel prices, etc. This is in contrast to the situation in system operation, when there is uncertainty about these parameters.

5.4 Modeling of Hydro Plants

Modeling of hydro plants requires mathematical descriptions of all flow points along the hydraulic path. Within the *Vista* environment this is handled by defining a series of nodes and arcs used to describe the configuration. Specific details of the hydraulic structure at each node or arc are provided by operational characteristics. For example, a reservoir node is described using a stage-storage relationship, a power arc is described using the unit characteristics curve and a tail water node is described using the mathematical relationship between elevation and flow at that point. Specific descriptions of these components are described in the following sections.

5.4.1 Turbine Characteristics

Vista uses the turbine characteristics of power-efficiency-flow to determine the optimum level of output for the unit. Unit performance characteristics were available in the original *Vista* setup of the NSPI hydro system. Updates to these unit performance coefficients were derived from revised unit performance data provided by NSPI for the units at Hells Gate, Nictaux, Malay and Paradise. Unit performance characteristics included in the original *Vista* implementation for NSPI were used for the remaining plants. Performance characteristic curves are entered in *Vista* via a power polynomial relationship representing a unit discharge- head – MW relation.

Unit operations are defined by maximum and minimum output capacity and flow operational limits and whether the unit is available for AGC, spinning or non spinning contributions.

5.4.2 Reservoir Storage Characteristics

Stage-storage relationships of all reservoirs are required to model the head and storage availability of the reservoirs. Stage-storage relationships were available in the original *Vista* setup.

5.4.3 Tailwater Elevation Characteristics

Tail water relationships are required in *Vista* downstream of each plant location. The tail water relationship describes the flow and elevation at that point in the system and in conjunction with head water levels, determines the head that is available for unit generation.

5.4.4 Spillway Characteristics

Vista allows for a number of different types of spillway definitions. These include spill gates, overflow weirs, stoplog structures, orifice gates, butterfly valves, uncontrolled canals and flashboards.

Relationships at all spillways in the NSPI hydro system were previously defined in the *Vista* model and were used in this study.

5.4.5 Hydrology

Daily historical natural inflow from 1976 to 1996 was available for each sub-basin of the Nova Scotia Power system. Annual total inflow volume for the entire system was calculated and ranked from dry to wet for the recorded historic period. As the Wreck Cove plant accounts for more than 50% of the hydro generation capacity, the annual inflow to the Wreck Cove plant was also calculated and ranked from dry to wet year. Three years, 1987, 1984 and 1990 were selected as the representative years of dry, average and wet hydrologic conditions to be consistent with both the Wreck Cove hydrology and the total system hydrology. The average hydrologic condition (1984) was used for all cases simulated in this study.

5.4.6 Reservoir Operational Constraints

Reservoir operational constraints define operational limits on reservoir and flow operations to ensure adherence to the recreational, fisheries or environmental requirements. These reservoir operational constrains are defined for each reservoir and/or flow arc within the *Vista* model. The model ensures that reservoir operations do not violate the operational constraint definition. For example, within *Vista* the minimum maintenance flow requirements on the Salmon Tail spillway between May and November of a year are specified. With these constraints defined, *Vista* will operate the river system to ensure no violations occur. Other typical constraints include the minimum and maximum elevation levels for each reservoir. For this study, the operational constraints were obtained from four NSPI Water Management and Fish Passage Operations documents (MOP-001-EVH, MOP-001-FUN, MOP-001-SHH and MOP-001-WHS) provided by NSPI.

5.4.7 Hydro Generating Unit Outages

Hydro generating unit outages are defined in the *Vista* model to represent realistic scenarios of operations. These outages are defined in a deterministic manner with a starting date and an ending date over the period of a year. The unit outage schedules in 2005 were provided by NSPI.

5.4.8 Run-of-River Hydro Plants

Vista optimizes the operations of each unit at each plant to meet load demand and minimize overall system cost. Many of the NSPI hydro plants do not change operations between analyses as they do not contribute to reserve and can not change their output as per the load demand. These hydro plants include the Malay Falls, Ruth Falls, Sandy Lake, Mill Lake, Tidewater, Roseway, Tusket, Falls Lake, Avon 1 and 2, Ridge, Gulch, Dickie Brook, Fall River and Harmony facilities. These hydro plants have a total capacity of some 59 MW. Due to their small contributions and as a mechanism to reduce computation time, these hydro plants were treated as run-of-river plants with their generation based on typical operations recorded from a single base run of the *Vista* model. The energy contributions from these plants therefore did not change from case to case. This simplification reduced computation time significantly.

5.5 Modeling of Thermal Plants

Modeling of thermal units in *Vista* has typically involved defining the thermal generation as an energy source which could be called on to provide energy at any level between the minimum and maximum capability of a plant without accounting for fuel usage or heat rate. For the Nova Scotia system this simplified approach was not suitable since in recent years some 85% of annual energy consumption has been supplied by thermal energy sources including coal, petcoke, natural gas and oil. It was essential to account for the variable heat rates of each thermal unit and other operational characteristics to derive at a reasonable dispatch. Consequently a new feature in *Vista* was developed specifically to handle dispatch of thermal units in a more realistic manner. This new approach uses the coefficients of heat rate versus output capacity to determine the heat consumption curve of a thermal unit that could be used in the model.

The heat consumption curves were developed for all thermal units and were input to the *Vista* model. These curves, coupled with fuel prices in $/MMBTU, were used to dispatch thermal units. The hourly fuel cost of a thermal unit is the product of fuel consumed in MMBTU and the fuel price in $/MMBTU.

5.5.1 Minimum Cycling Time of Thermal Units

The minimum cycling times of thermal units, in terms of minimum down/up time were provided by NSPI. At present only one cycling time can be defined in the *Vista* model. The cycling value therefore represents both the minimum down time and minimum up time for a thermal unit. The cycling time requirements provided by NSPI along with the values were used in the *Vista* model. Due to their confidentiality, the cycling time requirements are not presented in this report. In the *Vista* model, the required cycling times are applied at the beginning of each day for a 24 or 48 hour cycle and again at noon for a 12 hour cycle.

5.5.2 Thermal Unit Outages

The outages of thermal units are defined in the *Vista* model to represent realistic scenarios of operations. These outages are defined in a deterministic manner with a starting and an ending date over the period of a year.

The actual unit outage schedules in 2005 were provided by NSPI and were used in the modelling based on discussion with NSPI.

5.6 Modeling of Reserve Requirements

The reserve types that are relevant to NSPI and which were modeled in the *Vista* model include AGC spinning (regulation and load following), spinning and non spinning. AGC spinning requires that a generator allow its output to fluctuate quickly and automatically within a specified range between its minimum loading requirement and maximum output as per the system needs. Spinning only requires that a generator is able to change its output between minimum and output within a specified time frame and non spinning requires that the capacity can be synchronized on a short notice. Each generating unit in the model is specified as to its ability to meet each of these reserve types.

Many of the thermal units can not provide AGC spinning over their full operational ranges between minimum and maximum capacity. The minimum operating level for provision of AGC service is typically significantly above a unit's minimum generation level. Analysis of AGC service in the *Vista* model was modified to ensure that the AGC service could only be supplied if the thermal units were operating within the applicable range.

Reserve requirements were defined based on the cases analyzed. Spinning and non spinning requirements (interruptible load was eligible to provide non-spinning reserve) were kept constant for all cases. The requirement for AGC spinning service was adjusted to reflect the amount of installed wind capacity (based on three times the standard deviation of the load – minus wind variations as explained in Section 7.2 and Table 7-1). A summary of the reserve requirements is provided in Table 5-2. In *Vista* modeling, all reserve requirements were applied to the Metro bus.

Table 5-2: Reserve Requirements Modeled

Case	Wind Power (MW)	Year	AGC Spinning (MW)	Spinning (MW)	Non-Spinning (MW)
1	61	2008	46.2	32	140
2	61	2010	48.0	32	140
3	311 - Option 1	2010	63.1	32	140
4	311 - Option 2	2010	67.8	32	140
5	61	2013	50.2	32	140
6	581	2013	89.0	32	140
7	61	2020	54.8	32	140
8	311 - Option 1	2020	68.4	32	140
Run 9	311 - Option 2	2020	72.7	32	140
Run 10	581	2020	91.7	32	140
Run 11	781 - Option 1	2020	123.4	32	140
Run 12	781 - Option 2	2020	105.9	32	140
Run 13	981 - Option 1	2020	138.4	32	140
Run 14	981 - Option 2	2020	134.3	32	140

5.7 Modeling of System Load

5.7.1 System Load

The 2008 annual peak load and energy forecasts for the Nova Scotia electric system were calculated based on the load forecast given in the NSPI 2007 IRP Basic Modelling Assumptions, which were the original forecast values less the presumed DSM achievements. The total system hourly load for 2008 was then calculated based on the forecast 2008 system peak load and energy and 2005 system hourly load profile. In consultation with NSPI, it was assumed that the Canso Strait hourly load profile in 2008 would be same as that in 2005, i.e. would not be changed. Therefore, the 2008 hourly forecast for each of the remaining zones (Sydney, Metro, etc.) was calculated using the following steps:

(1) Creating 2005 residual hourly load profile by taking away the Canso Strait load from the system load

(2) Calculating 2008 residual peak and energy demands by taking away the Canso Strait load (unchanged) from total forecasted values

(3) Creating 2008 residual hourly load profile based on the results calculated from the two steps above

(4) Combining the 2008 residual hourly load profile obtained from step (3) and the Canso Strait hourly load profile

(5) Ensuring that both peak and energy demands calculated from the hourly load profile obtained in Step (4) are equal to the 2008 forecasted values by adjusting the 2008 residual hourly load profile in Step (3)

(6) Calculating zonal hourly load profiles for the remaining six zones (except for Canso Strait) by prorating the 2008 residual hourly loads based on zonal hourly loads in 2005.

The load profiles for years 2010, 2013 and 2020 were generated in a similar fashion.

5.8 Modeling of the New Brunswick Tie-Line

Prior to including the New Brunswick tie-line into the model a review of the transactions across this tie-line was performed. Analysis indicated that trade along the line was not firm but rather dynamic and dependent on the system status. Since firm exchange along the-tie line was not available, the New Brunswick tie-line was not modeled directly and the NSPI system was assumed to be isolated..

5.8.1 Interrupted/NB Import

The modeling results include a supply category referred to as Interrupted/NB Import. This category was used as a mechanism for absorbing energy shortfalls when generation dispatch was deemed to be difficult. These "supplies" were assigned to the locations of the large interruptible loads, i.e. 250 MW at the Canso Strait Bus and 100 MW at the West Bus. In actual operation, this supply category would be provided by various combinations of interruptions to the industrial loads, importing power through the New Brunswick Tie-Line or curtail wind power so that more thermal units could be dispatched..

5.9 Modeling of Wind Energy

Historical wind records for various locations across Nova Scotia were evaluated as described in Section 4. From this evaluation, hourly time series wind generation patterns were developed for all seven zones. For modeling purposes, these hourly wind times series patterns were associated with the modeled bus locations and entered into the model as firm energy supplies. This inherently means that the wind power can not be curtailed and that the model must arrive at a dispatch that uses all of the incoming wind. This can be problematic at times when the load is low and the wind power injection is high. During these times the model may be forced to shut down multiple thermal units to absorb the wind but this can lead to dispatch issues when load demand increases and the thermal units cannot be brought on-line fast enough to supply the increased load.

5.10 Modeling of Transmission Lines

Each of the equivalent transmission lines in the *Vista* model is defined by two directional limits. Figure 5-1 shows the representation of the existing transmission system. In this figure, all transmission lines between two major buses are represented by one equivalent bi-directional line, one for normal flow and the other for reverse flow. The numbers shown beside the directional limits that were assumed in each direction between the major buses (Note: there are no numbers shown for the NB tie-line indicating that this line was not modeled in the study). Transmission limits as defined in the model are further shown in Table 5-3.

Table 5-3: *Vista* Modeled Transmission Limits

From Bus	To Bus	Normal Direction (MW)	Reverse Direction (MW)
Canso Strait	Metro	400	400
Canso Strait	Pictou	180	200
Canso Strait	Truro	400	150
Metro	Valley	200	250
Metro	West	250	300
Pictou	Truro	600	300
Sydney	Canso Strait	500	200
Sydney	Pictou	350	150
Truro	Metro	900	500

5.11 Base Case

The base case dispatch was performed using the 2005 outage schedules of generating units/plants along with the 2008 load pattern as outlined previously. For the base case the generation system is comprised of the units/plants presented in Table 5-4.

5.11.1 Energy Usage Comparison to 2008

One approach to verifying the simulation results is to compare the LFO usage and New Brunswick import in 2005 with the 2008 base case simulation results. As noted previously, direct modeling of the New Brunswick tie line was not carried out but rather interruptible load usage was used as an indicator of energy shortfalls in the system. A comparison of the total LFO usage and New Brunswick tie-line usage recorded in 2005 with the total LFO and interruptible load usage for 2008 from the simulation is provided in Table 5-5. The 2007 values are also presented in this table but they are for reference only.

Simulation results for 2008 were found to be reasonable comparing with the 2005 actual outcomes. Additional usage of LFO generation as shown in the simulation case can largely be attributed to the higher load demand in 2008.

Table 5-4: Base Case Generation System

Thermal Plant Name	Unit No.	Capacity (MW)	Hydro Plant Name	Capacity (MW)
Tufts Cove	1	81	Wreck Cove	210.0
	2	93	Annapolis Tidal	3.7
	3	147	Avon	6.8
Lingan	1	155	Black River	22.5
	2	155	Nictaux	8.3
	3	155	Lequille	11.2
	4	155	Paradise	4.7
Pt. Aconi	1	171	Mersey	42.5
Pt. Tupper	2	154	Sissiboo	24.0
Trenton	5	150	Bear River	13.4
	6	157	Tusket	2.4
Tufts Cove	4	49	Roseway	1.8
	5	49	St. Margarets	10.8
Burnside	1	33	Sheet Harbour	10.8
	2	33	Dickie Brook	3.8
	3	33	Fall River	0.5
	4	33	Harmony	0.7
Tusket	1	24		
Victoria Junction	1	33		
	2	33		

Table 5-5: Base Case Energy Usage Comparison to Actual

Category	2008 Base Case (Simulation)	2005 (Actual)	2007 (Actual)
	(GWh)		
Interruptible Load	8.8	-	-
Net Transaction	-	123.1	285.2
LFO Usage	147.8	7.3	8.8
Total	**156.7**	**130.4**	**294.0**

5.11.2 Water Level Fluctuations - Hydro

Water level fluctuations of the modeled reservoirs in the system were reviewed by NSPI in the early stages of the project. Fluctuations were found to be reasonable. Most notably the maximum and minimum water level definitions were reviewed to ensure that modeled water levels were maintained within the bounds defined. An example of a water level trajectory from the 2008 (Run 1) simulation is provided in Figure 5-2 for Lake Rossignol on the Mersey River system.

5.11.3 Reserve Allocation

Reserves for the 2008 base case are defined as 46.2 MW for AGC spinning (regulation and load following), 32 MW for spinning and 140 MW for non spinning. Summary results for meeting reserve requirements over 2008 are shown in Table 5-6.

Table 5-6: Base Case 2008 Reserve

	AGC Spin (Regulation MW)	Spinning MW	Non-Spinning MW
Requirement (MW)	46.2	32	140
Average delivery (MW)	46.0	48	630
Time requirement is violated (%)	2.0	0	0
Average magnitude of violation (MW)	9.0	0	0

The results shown in Table 5-6 indicate that both spinning and non spinning requirements are consistently met. Violations of AGC spinning requirements occur 2% of the time at an average magnitude of 9.0 MW.

5.12 Dispatch Example - 2020 Case

The measures used to identify unit dispatch problems and difficulties were primarily load interruptions, LFO usage, and the total number of start-ups of the large thermal generating units. A number of key scenarios were identified early on as areas that might be problematic. These include times when load is low and wind is high. Under such circumstances it is possible that units would be shut down to accommodate the large incoming wind and low load scenario. The problem does not occur when shutting down thermal units to reduce generation but rather occurs when the load subsequently increases and units can not be brought on-line fast enough to meet the load requirement. In cases such as this, load interruptions and LFO usage increase dramatically. An example of such a situation is provided in Figure 5-3.

As shown in Figure 5-3, at 5 am on September 12 wind generation was relatively high at approximately 485 MW. As shown by the top of the graph, load demand was relatively low at some 885 MW. In order to absorb all the wind and meet load the only coal units used were Point Aconi, Point Tupper and Trenton 6. All the Lingan units and Trenton 5 were shut down. Several hours later load was increased but units could not be ramped up enough or brought on-line fast enough to accommodate the load increase. Generation shortfall was met using the LFO units and interruptible load.

Another measure of dispatch difficulties is the ability to meet reserve requirements, specifically AGC reserve, which increases with the wind capacity level. AGC reserve during this period was also violated dipping down to about 50 MW from the requirement of 105.9 MW as shown in Figure 5-4.

5.13 Summary of Dispatch Results

After the simulation of the base case was considered other cases were modeled and analyzed. The following sections summarize the findings.

5.13.1 Water Allocation (Spilling)

When the ancillary services increase along with the wind penetration level it was anticipated that spilling flow at the modeled hydro plants would correspondingly increase since generation at many of the plants that can supply these services would be curbed . Operations at these plants would also be curbed during low load high wind situations as described in the previous section. To assess the impact of this, the spilling magnitudes over the study period were assessed for each of the cases simulated. In this assessment only spillways that would carry flow that could not be turbined were considered. That is "spilling" flows that naturally feed downstream reservoirs such as that between Cheticamp and Gisborne were not summed into the statistical analysis of spilling. Rather spillways such as those on the Mersey River system which can serve to bypass flows that can not be used for generation were evaluated.

The study results indicate that for Cases 1 to 6 (covering the planning years of 2008, 2010 and 2013) spilling flows were found to be within 5% of each other. For the 2020 simulations results varied significantly as shown in Table 5-7.

Table 5-7: Summary of Water Spilling

Case	Description	% Spill Increase over 2020 Base Case
7 (Base)	61	-
8	311 - Option 1	3.5
9	311 - Option 2	13.2
10	581	5.9
11	781 - Option 1	7.9
12	781 - Option 2	8.5
13	981 - Option 1	42.6
14	981 - Option 2	30.0

The results shown in Table 5-7 indicate that for wind capacity injections of 981 MW, spilling increases by over 30% when compared to that of the 2020 base case. Differences in the spilling percentages for Cases 8 and 9 can be attributed to the different wind power plant locations.

5.13.2 Thermal Plant Usage

A graphical summary of thermal plant usage is provided in Figure 5-5 and the wind – coal usage relation has been extracted and shown in Figure 5-6.

Both figures indicate that wind capacity penetration offsets coal usage. Interrupted/NB Import quantities are shown in Figure 5-7. These results indicate that for all base case runs, the interrupted/NB Import category is used to compensate for energy shortfalls. With the increasing wind capacity, interrupted/NB Imports decreases up to 581MW of wind power installed capacity but then shows a marked increase for 781 MW of wind power installed capacity or higher.

5.13.3 Reserve Allocation

A review of all cases indicated that spinning requirements of 32 MW and non spinning requirements of 140 MW were always met. Statistical analysis of the achievement of the AGC spinning requirements was performed and is summarized in Table 5-8. The results indicate that violations of AGC spinning requirements are generally kept below 3% over a year for wind capacity injections up to 581 MW. For 781 MW of wind capacity or higher, AGC spinning violations are seen to occur between 5% and 10% of the time but are also seen to increase in magnitude showing an average violation varying between 12 and 27 MW.

In summary, meeting the necessary higher AGC spinning requirements is manageable at wind capacities up to 581 MW, but becomes increasingly problematic at higher penetrations. Incidences of AGC spinning shortfall nominally double at a wind penetration of 781 MW, and then double again at a wind penetration of 981 MW. However, the magnitude of violations in a year remains relatively small at approximately 0.3% and 2% of the annual regulation requirement for the 581 MW of wind power capacity in 2020 and the 981 MW of wind power capacity in 2020 cases respectively.

5.13.4 Transmission Usage

A summary of transmission line usage for all cases is provided in Table 5-9. The most heavily used lines for all cases are Canso Strait to Pictou and Sydney to Canso Strait which show line usage at maximum capacity between 18 and 32% of a year. Notably, maximum line usage decreased with increasing wind capacity penetration due to the availability of wind generation to meet load requirements on each bus.

5.14 Overall Summary of Findings

The simulated results indicate that for wind capacity injection of 981 MW, hydro spill increases by over 30% when compared to the 2020 base case.

For all cases, load interruptions are used to compensate for energy shortfalls when generation dispatch becomes difficult due to thermal cycling limitations. With increased wind capacity, load interruptions decrease with up to 581 MW of wind power capacity but then show a marked increase for 781 MW of wind power capacity or higher.

Spin requirements of 32 MW and non spin requirements of 140 MW were met in all runs. Statistical analysis of the achievement of AGC spin requirements was performed and indicated that violations of AGC spin requirements were generally kept below 3% for the year for wind power capacity injections up to 581 MW. For wind capacity of 781 MW or higher, AGC spin violations were seen to occur between 5% and 10% of the time but were also seen to increase in magnitude showing an average violation varying between 12 and 27 MW.

The most heavily used transmission lines for all cases were Canso to Pictou and Sydney to Canso which showed line usage at maximum capacity between 18 and 32% of the time. Notably, maximum line usage decreased with increasing wind penetration due to the availability of wind to meet load requirements on each bus.

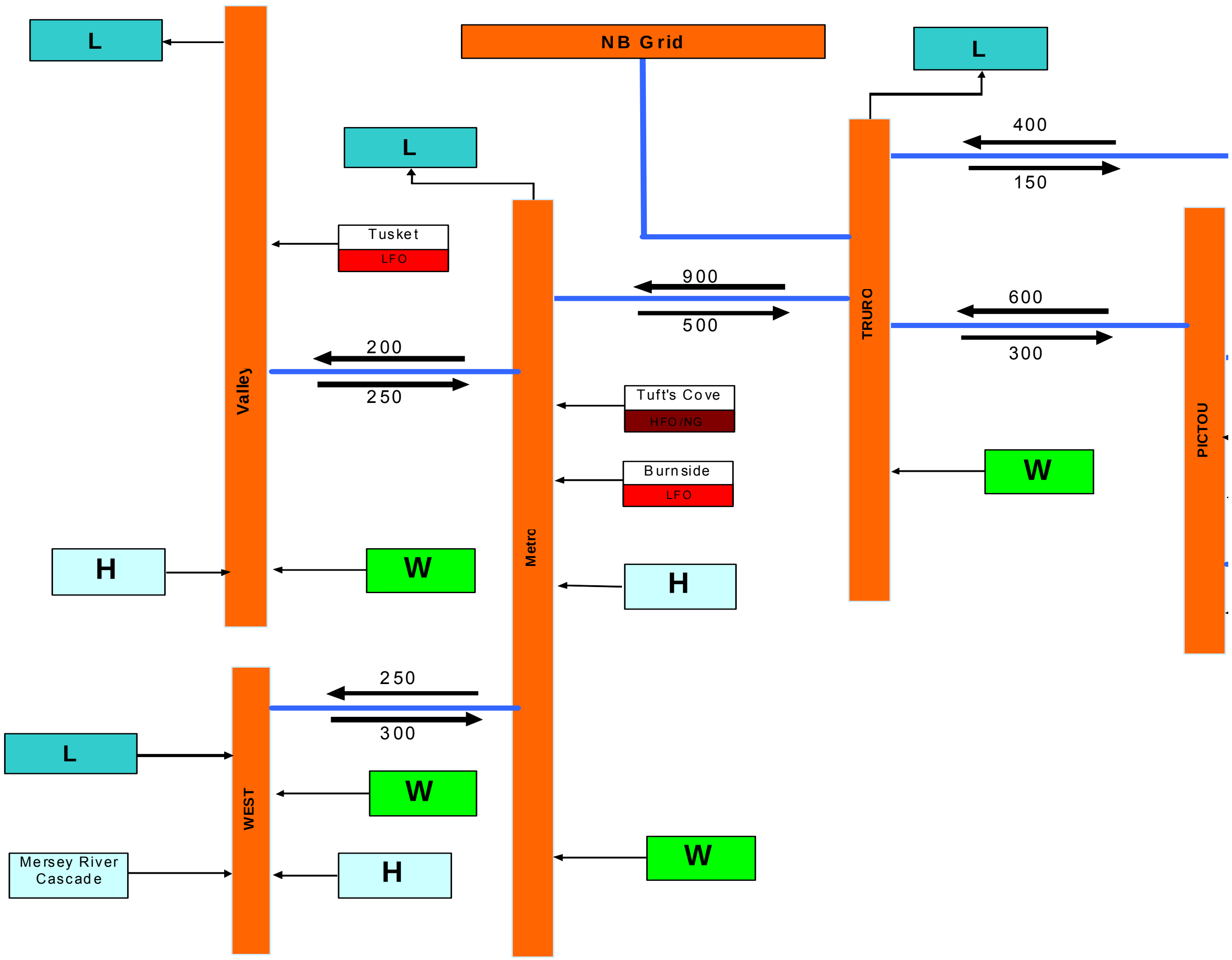
Table 5-8: AGC Spin Analysis for all Run Scenarios

Case	Scenario Description	Year	AGC Regulation Requirement (MW)	Average Delivered (MW)	Violation Time (%)	Average Violation Magnitude (MW)	Total Annual Regulation Requirement (MWh)	Hours when Requirement is Violated	Total Annual Violation (MWh)	Annual Violation (%)
1	61	2008	46.2	46.0	2.1	9.1	403,603	180	1643	0.41
2	61	2010	48.0	47.8	1.6	11.7	419,328	140	1641	0.39
3	311 - Option 1	2010	63.1	62.9	1.6	8.8	551,242	138	1210	0.22
4	311 - Option 2	2010	67.8	67.6	1.8	10.7	592,301	154	1645	0.28
5	61	2013	50.2	49.9	1.8	15.2	438,547	158	2396	0.55
6	581	2013	89.0	88.7	2.5	6.6	777,504	222	1457	0.19
7	61	2020	54.8	54.5	2.0	12.6	478,733	176	2216	0.46
8	311 - Option 1	2020	68.4	68.1	1.6	12.6	597,542	140	1763	0.30
9	311 - Option 2	2020	72.7	72.2	2.3	15.7	635,107	200	3133	0.49
10	581	2020	91.7	91.3	3.0	8.8	801,091	258	2258	0.28
11	781 - Option 1	2020	123.4	121.5	7.2	18.5	1,078,022	628	11605	1.08
12	781 - Option 2	2020	105.9	104.9	5.4	12.4	925,142	472	5834	0.63
13	981 - Option1	2020	138.4	134.8	10.6	26.8	1,209,062	922	24697	2.04
14	981 - Option 2	2020	134.3	130.9	10.1	26.5	1,173,245	886	23500	2.00

Table 5-9: Transmission Line Usage

Equivalent Line Name	Direction	Capacity MW	% of Time Reaching Maximum Capacity — Case 1	2	3	4	5	6	7	8	9	10	11	12	13	14
Canso To Metro	Normal	400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	37.8	0.0	34.1	33.0
	Reverse	400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.5	0.6
Canso to Pictou	Normal	180	32.0	29.8	28.7	25.7	31.0	26.7	29.4	27.9	24.9	26.8	20.1	27.7	20.0	20.1
	Reverse	200	2.0	2.3	1.9	2.4	2.3	2.8	2.7	2.6	3.6	3.3	12.8	5.1	14.2	13.4
Canso to Truro	Normal	400	13.5	15.6	17.9	16.9	13.8	16.0	14.5	16.9	15.2	16.4	15.3	13.8	12.9	13.4
	Reverse	150	0.0	0.0	0.0	0.0	0.1	0.5	0.1	0.2	0.4	0.9	19.8	3.0	22.2	21.7
Metro to Valley	Normal	200	0.0	0.0	0.1	0.2	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
	Reverse	250	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Metro to West	Normal	250	0.3	0.9	0.4	0.1	1.0	0.3	1.3	0.3	0.4	0.2	1.6	0.7	0.9	0.8
	Reverse	300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pictou to Truro	Normal	600	18.4	16.0	19.9	19.8	18.2	19.3	17.7	18.1	20.4	17.3	8.1	14.1	4.9	5.5
	Reverse	300	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.9	1.0
Sydney to Canso	Normal	500	30.1	32.6	28.7	32.1	30.3	26.0	28.7	27.5	28.2	25.5	23.4	19.4	18.6	18.8
	Reverse	200	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.4	0.4
Sydney to Pictou	Normal	350	15.3	16.0	17.1	15.8	17.1	19.5	17.4	17.8	17.2	18.2	17.9	21.7	17.0	16.9
	Reverse	150	0.0	0.1	0.0	0.1	0.0	0.1	0.0	0.1	0.1	0.6	1.6	1.2	5.1	4.7
Truro to Metro	Normal	900	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.1	0.5	0.0	0.5	0.3
	Reverse	500	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Figure 5-1: Existing Transmission Layout as Modeled



Legend: H-Hydro, W-Wind, L-Load

Figure 5-2: Lake Rossignol Year Long Water Level Trajectory

Figure 5-3: Run 12 Two-Hourly Dispatch View

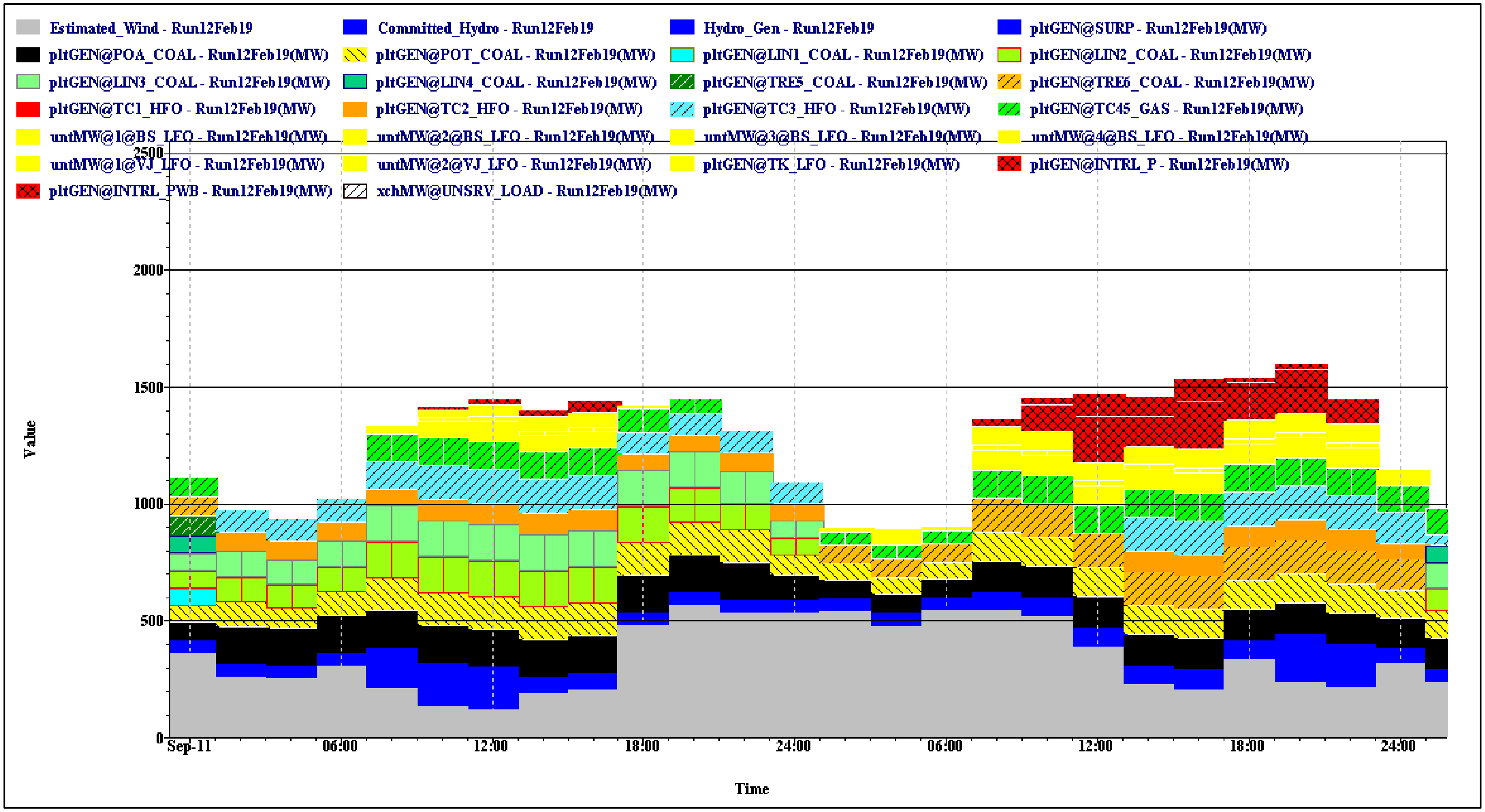


Figure 5-4: Regulation Reserve for Run 12 – Sept 12th View

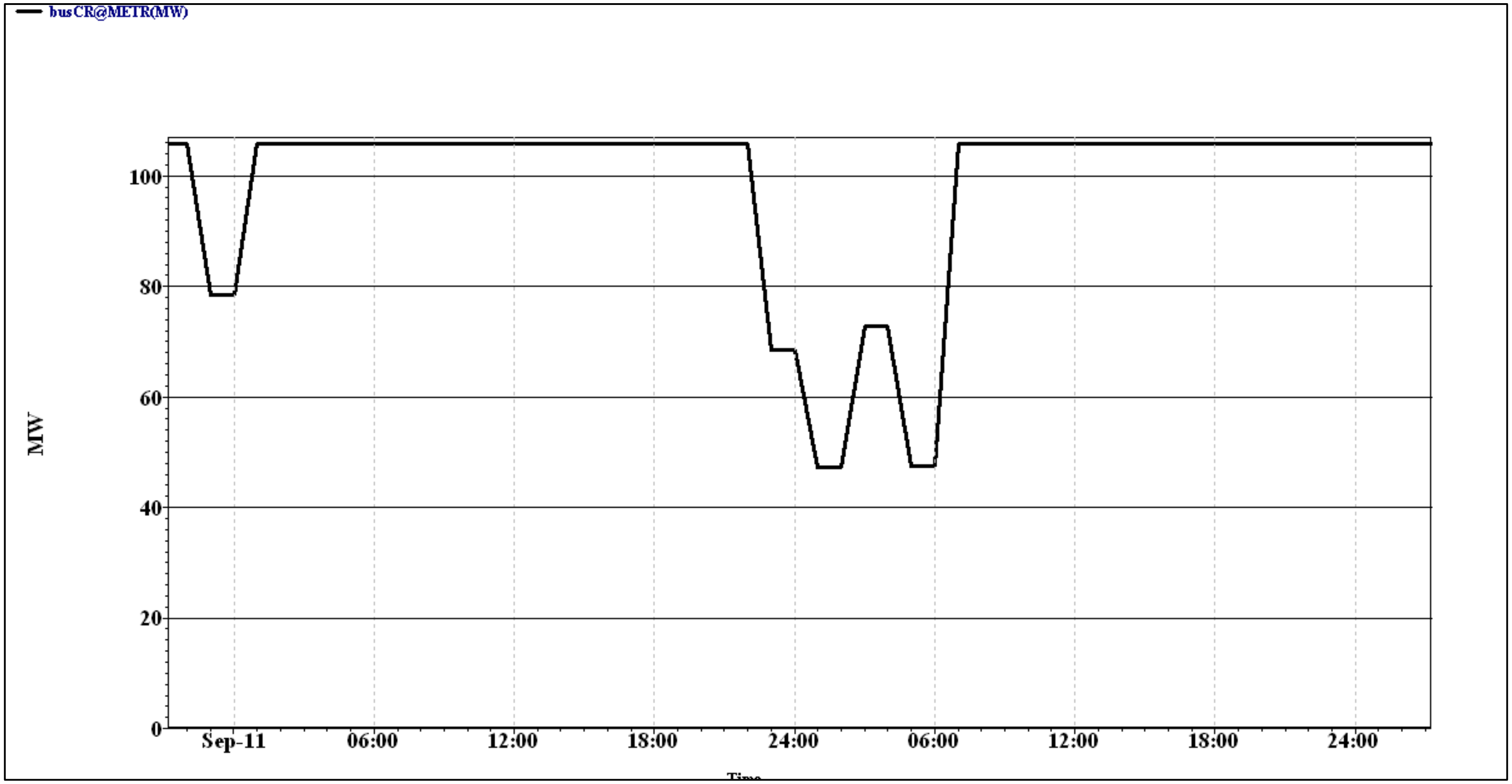
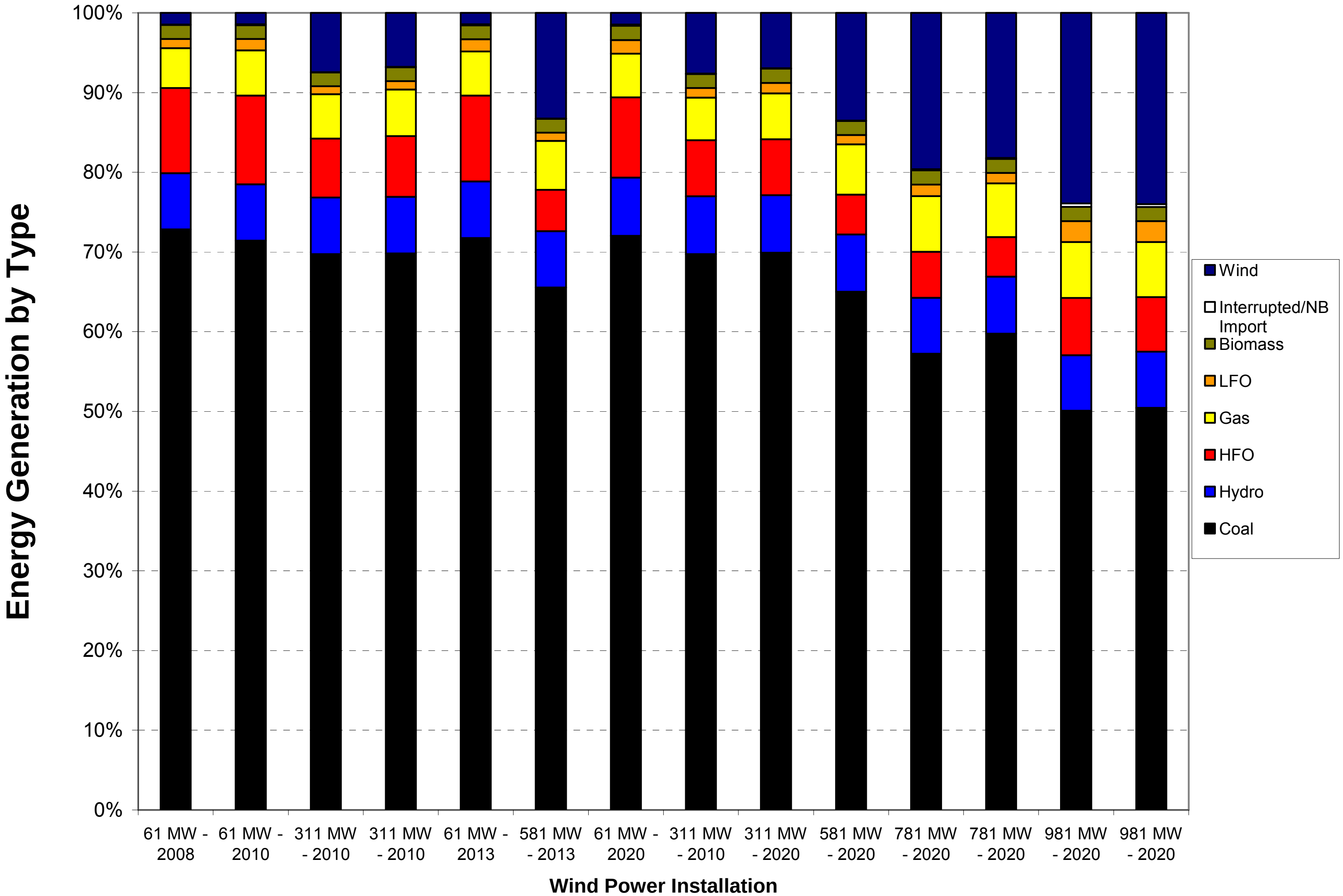


Figure 5-5: Summary Plant Usage



Note: Results are indicative not definitive.

Figure 5-6: Generation of Coal and Wind Power Plants

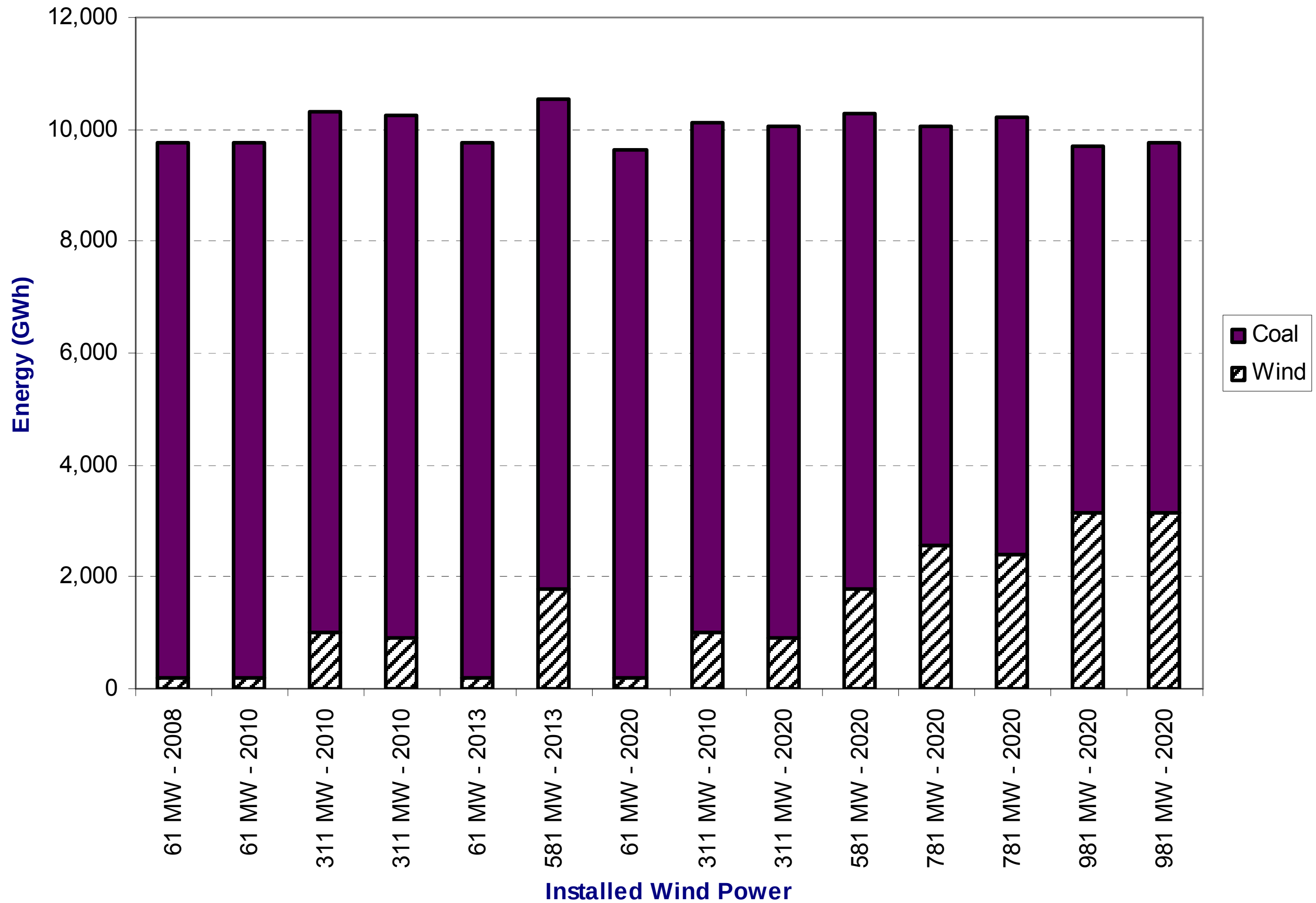
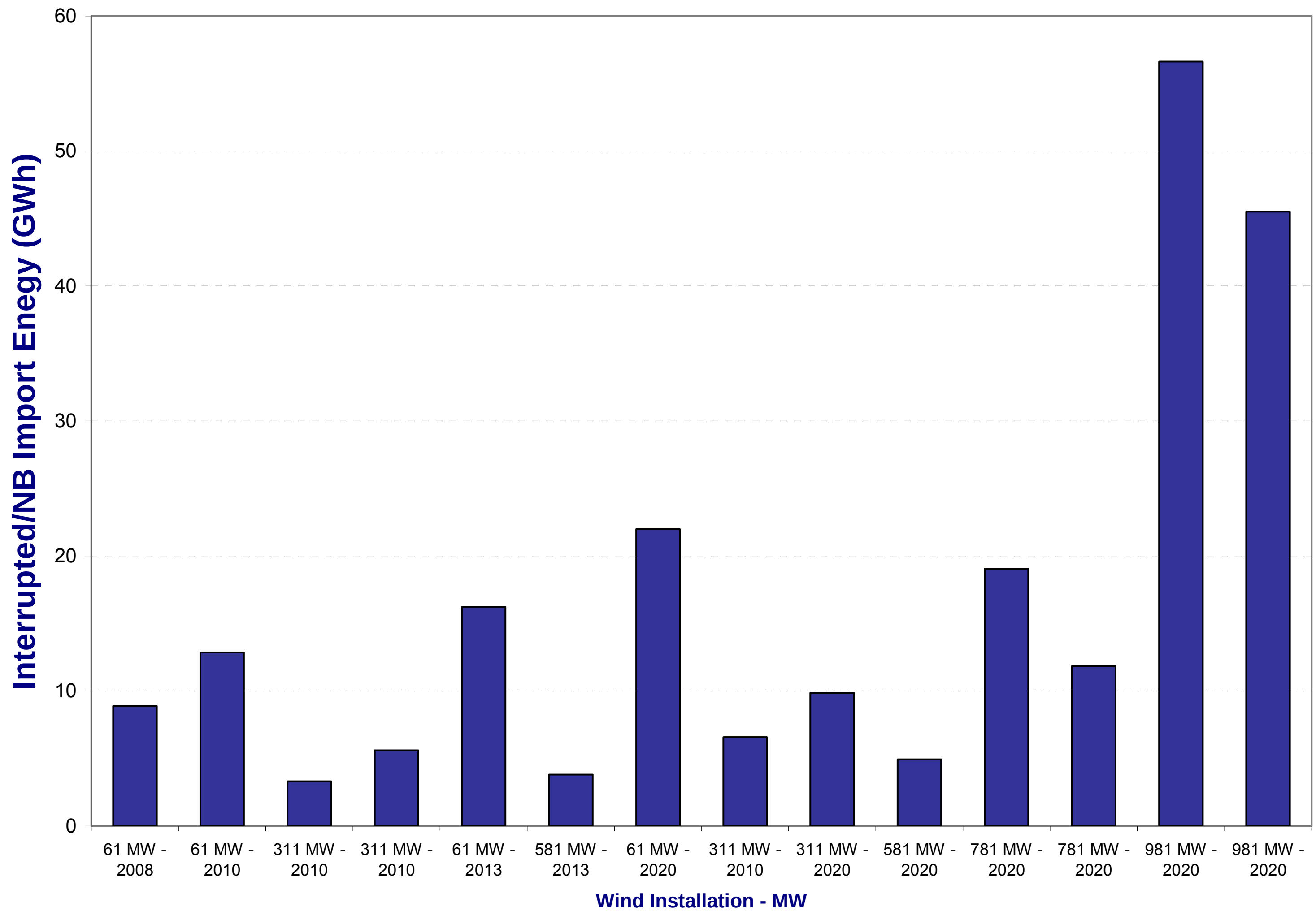


Figure 5-7: Summary of Interrupted/NB Import



6. Transmission System Modeling

6.1 Introduction

This section presents a preliminary impact assessment of various wind capacity levels on the NSPI transmission system. The assessment is based on load flow and contingency analyses.

The study was carried out in two phases:

1) Phase 1: Additional wind capacity injection of 520 MW in 2013
2) Phase 2: Additional wind capacity injection of 400 MW in 2020 for total incremental wind capacity of 920 MW.

The objectives of the study are:

- Assess the impact of wind capacity injection into the Nova Scotia power system on operation and reliability by means of steady state assessments
- Identify the transmission reinforcement requirements to incorporate the wind capacity injections under study
- Estimate the costs associated with any required transmission reinforcements.

This preliminary assessment study assumed a cluster of wind generations in each zone that were incorporated into a single node within that zone. Actual wind facilities may be installed at a number of locations within a zone and will be connected to the NSPI transmission system at different voltage levels. It should be noted that the cost estimates presented in this report do not include the costs associated with specific generation interconnections, which may typically include a tap line and local transmission/distribution system upgrading costs. These costs could be determined during the System Impact Assessment phase.

6.2 Steady State Reliability Requirements

6.2.1 NPCC Definition of Contingency

The NSPI system is part of the NPCC system. NPCC's Document A-2 (Basic Criteria for Design and Operation of Interconnected Power Systems) applies to its transmission planning and operation. The other referenced NPCC documents include A-5 (Bulk Power System Protection Guide), A-11 (Special Protection Systems Criteria), and C-18 (Procedures for Testing and Analysis of Extreme Contingencies). However, the scope of this report is limited to load flow and contingency studies for providing a preliminary assessment of the impacts of additional wind generation capacity. The dynamic studies required by the NPCC criteria are not included in the scope of this assessment.

NPCC Document A-2 treats the loss of multiple transmission elements as a single contingency if the event has common features. For example, a phase to ground fault on a transmission line coincident with a stuck breaker will result in the loss of the two lines sharing that breaker. The NPCC definition of a Contingency and related definitions are given as follows:

Contingency — An event, usually involving the loss of one or more elements, which affects the power system at least momentarily.

NPCC Specific Definitions:

NPCC Emergency Criteria Contingencies — The set of contingencies to be observed when operating the bulk power system under emergency conditions.

NPCC Normal Criteria Contingencies — The set of contingencies to be observed when operating the bulk power system under normal conditions.

Double Element Contingency — A contingency involving the loss of two elements.

Single Contingency — A single event, which may result in the loss of one or more elements.

Single Element Contingency — A contingency involving the loss of one element.

Limiting Contingency — The contingency which establishes the transfer capability.

First Contingency Loss — The largest capacity outage including any assigned Ten-Minute Reserve which would result from the loss of a single element.

Second Contingency Loss — The largest capacity outage which would result from the loss of a single element after allowing for the First Contingency Loss.

6.2.2 Nova Scotia Reliability Criteria

As part of the Maritimes Area, Nova Scotia shares its reserve requirements with New Brunswick, Prince Edward Island, and Northern Maine. Nova Scotia carries sufficient Reserve (reserve adequacy) to meet a "0.1 day per year" reliability criteria, which currently amounts to approximately 20% of the peak firm load.

Operating Reserve is shared under agreement with New Brunswick to accommodate the largest generation contingency in the Maritimes Area (680 MW net at Point Lepreau). Reserve sharing among load-serving entities in the Maritimes Area is capped at 10% of the annual peak coincident demand which is forecasted to be 5,800 MW by 2011/2012. The Nova Scotia share (based on coincident peak load ratio) of 10-Minute Reserve is approximately 40% of the total reserve requirement, or, 232 MW, but is capped at the largest on-line unit in Nova Scotia (174 MW when Point Aconi is running). In addition, Nova Scotia must carry 50 MW of 30-Minute Reserve and 32 MW of Synchronized Reserve. This results in total Operating Reserve requirements of about 256 MW.

6.2.3 Nova Scotia Steady State Performance Criteria

The following steady state criteria are used to determine the transmission reinforcement requirements:

1) Steady state voltages should be within the following ranges:

    a. 0.95 pu – 1.05 pu – System Intact
    b. 0.90 pu – 1.10 pu – Contingency

2) Thermal loading on a transmission line or transformer should not exceed 110% of:
    a. Rate A – Summer season
    b. Rate B – Winter season

Within the NSPI system, if thermal loading of a transmission line or transformer is found to exceed 100% of its rating but by not more than 10%, it is deemed acceptable mitigation practice to use a generation re-dispatch to correct the issue as long as there is sufficient generation available and if the re-dispatch reduces the loading on all transmission lines and transformers to at or below 100% of their thermal ratings. In some cases, overloading over 10% could also be eliminated by generation re-dispatching.

6.3 Inputs to the Load Flow Model

6.3.1 Introduction

The inputs to the PSSE load flow models include the additional wind power capacities to be studied in each of the six zones, the contingency list and the identified transmission reinforcements by 2020. These are described in the following sections.

6.3.2 Wind Power Generations

The additional wind power capacities under study for the years 2013 and 2020 are shown in Table 6-1.

Table 6-1: 2013 and 2020 New Wind Power Injection

Zone	West	Valley	Truro	Pictou	Canso Strait	Sydney
Bus	89245	89340	89110 89135 89145	89090	89050	89007
Bus Location	Milton	Canaan	Onslow	Trenton	Port Hastings	Victoria Junction
2013 Wind (MW)	30	110	110	140	110	20
Additional 2020 Wind (MW)	100	0	100	0	200	0

In 2013, the highest new wind generation area is in the Pictou zone, while the lowest amount of new wind power generation is in the Sydney zone. The total new wind generation capacity under study is 520 MW.

From 2013 to 2020, additional wind power generation capacity (400 MW) is to be studied in the West, Truro and Canso Straits zones. The 100 MW allocated to the Truro zone is split into three locations; namely, Onslow (40 MW), Springhill (30 MW) and Maccan (30 MW)[1]. The analysis for the selected generation injection points has taken into account the presumed new 345 kV transmission line as described in Section 6.3.5.

6.3.3 Major Transfer Limits and Special Protection Schemes

The existing Nova Scotia transmission system includes the defined major transfer interfaces, as listed below:

- NS-NB Transfer Interfaces

[1] New wind generation is split among three buses because the analysis showed that transmission would be overloaded if all of the wind generation in the Truro Zone is placed at the Onslow bus.

- Cape Breton (CB) Export Transfer Interfaces
- Onslow Import Transfer Interfaces
- Onslow South Transfer Interfaces.

The existing power transfer limits on these interfaces were determined through dynamic stability studies. If any of these interface flows approach the set limits, a Special Protection Scheme (SPS) is invoked under the selected contingencies to maintain the system stability and to ensure that no thermal loading and voltage limits are violated.

Table 6-2 lists the Line Names for major 345 kV, 230 kV and 138 kV transmission lines in the Nova Scotia transmission system. Some of these Line Names and designations are used in the following sections.

Table 6-2: Reference List of Transmission Lines

Line Name	Voltage	From Bus	To Bus	Ckt
L8001	345 kV	Onslow (89125)	Meramcook(87402) via 87381	1
L8002	345 kV	Onslow (89125)	Lakeside (89195)	1
L8003	345 kV	Onslow (89125)	Hopewell (89120)	1
L8004	345 kV	Hopewell(89120)	Woodbine(89045)	1
L7001	230 kV	Onslow(89130)	Brushy Hill(89200)	1
L7002	230 kV	Onslow(89130)	Brushy Hill(89200)	2
L7003	230 kV	Onslow(89130)	Port Hastings (89050)	1
L7004	230 kV	Onslow(89130)	Port Hastings (89050)	2
L7005	230 kV	Onslow(89130)	Port Hastings (89050)	3
L7008	230 kV	Brushy Hill(89200)	Bridgewater(89240)	1
L7009	230 kV	Brushy Hill(89200)	Bridgewater(89240)	2
L7011	230 kV	Lingan (89000)	Port Hastings (89050)	1
L7012	230 kV	Lingan (89000)	Port Hastings (89050)	2
L7014	230 kV	Lingan (89000)	Woodbine (89042) via 89040	1
L7015	230 kV	Point Aconi(89043)	Woodbine(89042)	1
L7016	230 kV	River Ryan	Sysco EAF (retired)	1
L6503	138 kV	Trenton (89090)	Onslow (89110) via 89100	1
L6513	138 kV	Onslow (89110)	Springhill (89135) via 89134	1
L6516	138 kV	Victoria Junct. (89007)	Hastings (89051) via 89056	1
L6533	138 kV	Lingan (89000)	Victoria Junct.(89007) via 89005	1
L6534	138 kV	Lingan (89000)	Victoria Junct.(89007) via 89006	1
L6537	138 kV	Glen Tosh (89031)	Hastings (89051) via 89033/89057	1

6.3.3.1 (1) NS-NB Transfer Interface

The interconnection between Nova Scotia and New Brunswick comprises of the following three transmission circuits:

- Onslow (NS) – Meramcook (NB) - Salisbury (NB) 345 kV single circuit
- Two single circuit 138 kV lines from Springhill (NS) to Meramcook (NB), which is further connected to Prince Edward Island via AC submarine cable.

The transfer limit between Nova Scotia and New Brunswick largely depends on the loading of a single 138 kV transmission line from Onslow to Springfield with the loss of L8001 (NS-NB 345 kV transmission line). This line is rated at 110 MVA in the summer season and 165 MVA in the winter season. Special Protection Systems (SPSs) are employed to manage imports and exports greater than 100 MW.

6.3.3.2 (2) Cape Breton Export Transfer Interface

The Cape Breton (CB) Export represents the outgoing flows from the Cape Breton region. It comprises of the following five transmission circuits:

- Single 345 kV transmission circuit from Woodbine to Hopewell (L8004)
- Three 230 kV transmission circuits from Port Hastings to Onslow (L7003, L7004 and L7005)
- Single 138 kV transmission circuit from Port Hastings to Trenton (L6515)

The limit for CB Export is normally 870 MW. SPSs trip generation for certain contingencies and operating conditions.

6.3.3.3 (3) Onslow Import Transfer Interface

The Onslow 345 kV substation connects 345 kV transmission circuits to the east, west and the New Brunswick system. The Onslow Import Transfer Interface represents the incoming flows on the following transmission circuits:

- Single 345 kV transmission circuit from Hopewell to Onslow (L8003)
- Three 230 kV transmission circuits from Port Hastings to Onslow (L7003, L7004 and L7005)
- Single 138 kV transmission circuit from Trenton to Onslow (L6503)

SPSs are armed to manage transfers on this interface.

6.3.4 Contingency List for Assessments - 2013

A total of 22 critical contingencies are identified for the 2013 contingency study and are shown in Table 6-3.

Table 6-3: List of Contingencies for Steady State Analysis

Loss of single element	Line Fault with Breaker Failure	Loss of 2 Lines on Common Tower
A01: L7012	B01: L7012 & L7014	C01: L7003 & L7004
A02: L7014	B03: L7012 & L7004	C02: L6534 & L7011
A03: L7005	B04: L7005 & L7018	C03: L8004 & L7005
A06: L8004	B05: L8003 & No.1 T/F at Onslow	
A07: L8003	B06: L8002 and L8003	
A08: L8002	B07: L8003 and L8004	
A09: L8001	B08: Lingan Unit 3 & 4	
A10: L6503	B09: L8001 & No.2 T/F at Onslow	
A12: Hopewell 345 kV transformer		
A13: L7018		
A14: Lakeside 138 kV bus		
Total: 11	Total: 8	Total: 3
Grand Total	22	

The contingency list includes 11 single branch contingencies, 8 breaker failure contingencies and 3 tower failure contingencies.

6.3.5 Transmission Reinforcement Requirement By 2020

6.3.5.1 New 345 kV Transmission Line

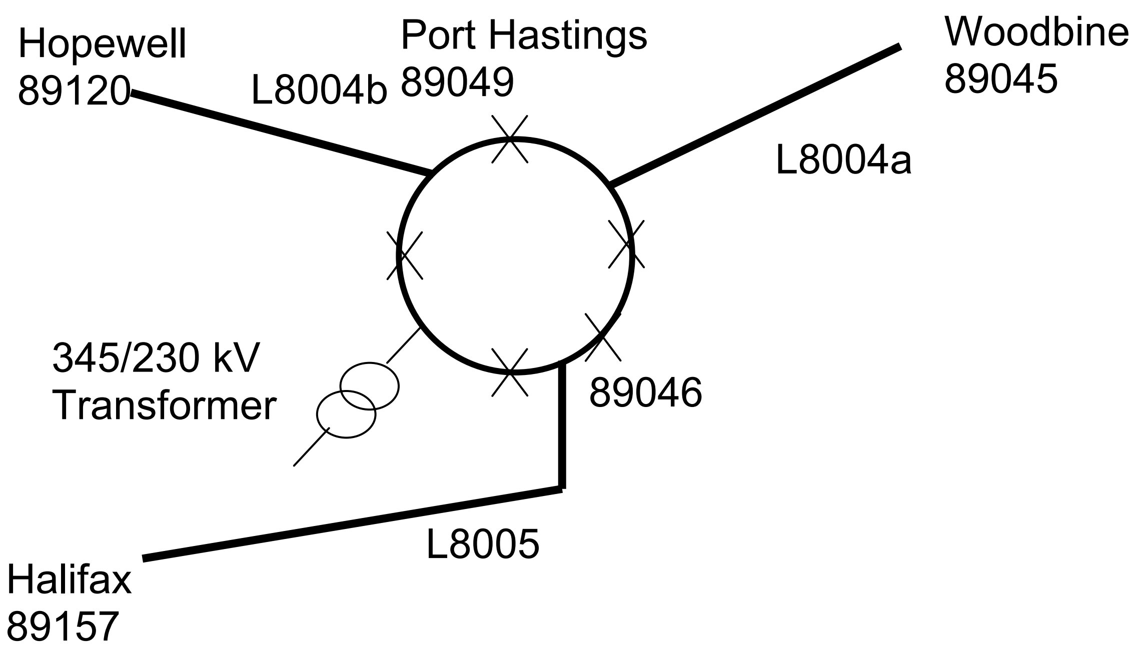
The Cape Breton interface determines the east-west power flow transfer levels.. The 2020 load flow case assumed that an additional 200 MW of wind generation would be added in the Canso Strait zone, for a total of 310 MW of additional wind power capacity in this zone (this corresponds to the 981 MW of total installed wind capacity case). Load flow analysis demonstrated that there is insufficient transmission capacity to accommodate this additional generation. This study examined the option to build a new 345 kV transmission line from Port Hastings to Halifax. This would help increase the interface limit for CB export, reduce the flows into Onslow, maintain the voltage profile under contingencies and considerably enhances the reliability of the east-west transmission corridor. The proposed reinforcements comprise the following facilities:

- A new 220 km long 345 kV transmission line from Port Hastings to Halifax
- Existing Woodbine – Hopewell 345 kV line looped into Port Hastings
- A new 345 kV substation at Hastings including a 400 MVA 345/230 kV transformer
- A new 345 kV substation at Halifax including a 400 MVA 345/230 kV transformer.

The proposed bus configuration at Port Hastings is shown in Figure 6-1. It is noted that the existing line L8004 is looped in/out at new Port Hastings 345 kV substation and is electrically split into two separate transmission circuits:

- L8004a (Woodbine – Port Hastings)
- L8004b (Port Hastings – Hopewell).

Figure 6-1: Bus Configuration at New Port Hastings 345 kV Substation



6.3.5.2 Reactive Power Requirements

The proposed new 345 kV transmission line would generate a significant amount of reactive power due to its high voltage and long distance.

A number of load flow simulations were performed to determine the size of the required reactive compensation and the locations. A preliminary analysis shows that 2 x 50 MVAR shunt reactors at Port Hasting are required to maintain the system voltage profile under light load conditions.

If not appropriately equipped, wind turbines could trip at extreme low voltages during disturbance conditions and thus it is very important that wind turbines have low voltage ride-through capability (LVRT). At the same time, it is also necessary to provide dynamic reactive power support in the Metro area under various severe contingencies to support system voltages and to avoid system collapse. Accordingly, a new SVC is presumed at Tufts Cove.

The proposed new reactive power compensation facilities include:

- A new SVC with capacity of +100 MVAR and -50 MVAR at Tufts Cove
- 2 x 50 MVAR shunt reactors at Port Hastings.

The actual location and size of the new SVC should be further verified after dynamic stability analysis.

6.3.6 Updated Contingency List for Assessments - 2020

Due to the proposed new 345 kV transmission line from Port Hastings to Metro, the existing contingency designations involving L8004 have been revised and are shown in Table 6-4. In addition, taking into consideration the bus configuration shown in Figure 6-1, some new contingencies are defined, which are listed in Table 6-5.

Table 6-4: Revised Contingencies

Cont	Existing	Revised
A06	Loss of Woodbine-Hopewell 345 kV line (L8004)	Loss of Hastings-Hopewell 345kV line (L8004b)
B07	Loss of Woodbine-Hopewell & Hopewell-Onslow 345kv lines (L8003 and L8004)	Loss of Hastings-Hopewell & Hopewell-Onslow 345kV lines (L8003 and L8004b)
C03	Loss of Woodbine-Hopewell (L8004) & Hastings-Onslow (L7005)	Loss of Hastings-Hopewell (L8004b) & Hastings-Onslow (L7005)

Table 6-5: New Contingences

New Contingencies	Descriptions	Label
a15	Loss of Woodbine-Hastings 345 kV line	L8004a
a16	Loss of Hastings-Halifax 345 kV line	L8005
b10	Loss of Woodbine-Hastings & Hastings-Hopewell 345kv lines	L8004a & L8004b
b11	Loss of Hastings-Halifax 345 kV line & Hastings 345/230 kV T/F	L8005 & T/F at Halifax
b12	Loss of Hastings-Hopewell line & Hastings 345/230 kV T/F	L8004b & T/F at Halifax

6.4 Description of the PSS/E Load Flow Models

NSPI provided a number of PSS/E load flow base cases to Hatch for the years 2007, 2010 and 2020. These models represent complete interconnected power systems of Nova Scotia, New Brunswick and Prince Edward Island and different operating conditions. Hatch updated these load flow models by incorporating various wind generation levels in years 2013 and 2020. The load flow simulations were performed using PSS/E 30.3 for winter peak, summer peak, summer light and summer minimum load conditions along with various export levels to the New Brunswick system.

Data for the presumed transmission reinforcements were obtained either from NSPI or from Hatch's in-house database.

6.4.1 2013 Load Flow Models

The following four load flow cases were developed to represent both typical and stressed system operating conditions considering generation dispatches, load and export scenarios. Table 6-6 provides a brief description of the base cases. New wind generation dispatches are given in Table 6-7.

Table 6-6: 2013 Load Flow Cases

No	Load	New Wind Injection (MW)	Export (MW)
a1	Winter Peak	520	175
a2	Summer Peak	520	175
a2	Summer Light	460	350
a3	Summer Minimum	460	0

Table 6-7 New Wind Generation Dispatches in 2013 Load Flow Models

		West	Valley	Truro	Pictou	Canso Straits	Sydney	
Year	Load	89245	89340	89110	89090	89050	89007	Total
2013	Winter Peak	30	110	110	140	110	20	520
2013	Summer Peak	30	110	110	140	110	20	520
2013	Summer Light	30	50	110	140	110	20	460
2013	Summer Minimum	30	50	110	140	110	20	460

The load flow cases mentioned above took into account the following factors:

- The assumed wind generation capacity additions are incorporated into the new load flow models
- The existing generating units in the Metro area (Burnside and Tufts Cove), Pictou and the West are either shut down or their outputs are reduced to allow the incorporation of new wind generation of 520 MW. Wind generation capacity of 520 MW for Summer Light and Summer Minimum loads is also studied as a sensitivity analysis
- The output of the SVC at Brushy Hill is kept at $\pm$ 5 MVAR under normal operating conditions in order to provide maximum dynamic compensation during the contingency
- Bus voltages at 230 or 345 kV levels are within 1.02 pu to 1.04 pu in order to maintain the acceptable system voltage profile during a contingency.

Table 6-8 gives the interface flows of the four load flow cases under normal operating conditions.

Table 6-8 Interface Flows of 2013 Load Flow Cases

Case No	Load	Wind	export	CB	Onslow Import	Onslow South	Losses
		MW	MW	MW	MW	MW	MW
a1	Winter Peak	520	175	712	633	713	73
a2	Summer Peak	520	175	704	663	657	67
a3	Summer Light	460	350	647	638	487	56
a4	Summer Minimum	460	0	294	328	485	27

The highlighted interface flows indicate that SPS will be required under relevant contingencies.

6.4.2 2020 Load Flow Models

Similar to the 2013 load flow models, four load flow cases were developed for the year 2020 as listed in Table 6-9 below. The new wind generation dispatches for different zones in different load flow models are given in Table 6-10.

Table 6-9: 2020 Load Flow Cases

No	Load	New Wind Injection (MW)	Export (MW)
b1	Winter Peak	920	175
b2	Summer Peak	760	175
b3	Summer Light	710	350
b4	Summer Minimum	600	0

Table 6-10: New Wind Generation Dispatches in 2020 Load Flow Cases

		West	Valley	Truro	Pictou	Canso Straits	Sydney	
Year	Load	89245	89340	89110 89135 89145	89090	89050	89007	Total
2020	Winter Peak	130	110	210	140	310	20	920
2020	Summer Peak	30	50	210	140	310	20	760
2020	Summer Light	30	0	210	140	310	20	710
2020	Summer Minimum	30	0	210	140	200	20	600

The load flow cases mentioned above were developed taking into account the following factors:

- The NSPI system should maintain the minimum thermal generating capacities on-line for security reasons. As such, only the winter peak case can incorporate the entire new wind generation of 920 MW. The other load flow cases can not fully incorporate the wind generation capacity that is under study. The curtailed new wind generation's capacity would mainly be located in the West and Valley zones

- The outputs of the SVCs at Brushy Hill and Tufts Cove are kept at ± 5 MVAR under normal operating conditions in order to provide maximum dynamic compensation during contingency situations

- Bus voltages at 230 or 345 kV levels are within 1.02 pu to 1.04 pu in order to maintain the acceptable system voltage profile during contingency situations.

Table 6-11 below shows the interface flows under normal operating conditions.

Table 6-11: Interface Flows of 2020 Load Flow Cases

Case No	Load	Wind	Export	CB	Onslow Import	Onslow south	Losses
		MW	MW	MW	MW	MW	MW
b1	W. Peak	920	175	866	870	712	68
b2	S. Peak	760	175	756	599	520	47
b3	S. Light	710	350	609	605	390	40
b4	S. Min	600	0	270	219	430	21

It is noted that CB Export exceeds 700 MW in case b1 (Winter Peak) and b2 (Summer Peak). However, with the assumed additional 345 kV transmission line, SPS will not be operated for the loss of L8004b (Port Hastings to Hopewell 345 kV line). This has been further verified in the contingency analysis study below.

6.5 Load Flow Study and Contingency Analysis

6.5.1 2013 Load Flow Study

6.5.1.1 Study Procedure:

Steady state AC contingency analysis (PSS/E activity ACCC) was used to assess the impacts of the assumed wind power capacity injection into the NSPI transmission system. The purpose of the analysis was to test the adequacy of the NSPI system for incorporation of the additional amount of wind generation.

All nodes (buses) and branches above the 69 kV level in the NSPI system are monitored for any loading or voltage violations. The list of contingencies as defined in Table 6-3 is applied in all power flow cases described in Table 6-6. If the results of the contingency analysis showed any criteria violations, mitigation measures were evaluated in the form of additional reactive power compensation requirements, transmission line upgrades or generation re-dispatch needs.

6.5.1.2 Contingency Analysis Results:

PSS/E function ACCC was used for performing contingency analysis on the above mentioned four load flow cases. The results of the assessment are based on the Rate B with 110% loading limit in the winter peak case and Rate A with 110% loading limit for summer peak, summer light and summer minimum cases. The following are the main observations:

- No overload and voltage violations are observed for the winter peak and summer minimum cases

- For summer peak case, Lingan – Port Hastings No.1 (L7011) circuit overloads by 121% for the simultaneous loss of L7012 and L7014. This overloading is eliminated with the application of SPS

- Under winter peak conditions, NSPI transmission system losses reduce by about 7 MW with the incorporation of the 520 MW of additional wind generation capacity as opposed to the case without the additional wind generation incorporated.

A separate assessment of the sensitivity load flow case, with full generation dispatches in the Sydney zone, shows that the Trenton – Onslow 138 kV transmission line (L6503) overloads up to 15% for any contingency involving the loss of L8003 (Hopewell-Onslow 345 kV transmission line).

It is known that the rating of L6503 is limited by the breaker at Trenton. The existing breaker is rated at 1,200 Amps and if it is replaced with 1,500 Amps breaker, L6503 could be rated at 358 MVA in the winter and at 297 MVA in the summer.

Two other load flow cases of Summer Light and Summer Minimum Load cases, with full dispatches of wind power injections of 520 MW, show that there are no voltage and loading violations observed in the NSPI system.

6.5.2 2020 Load Flow Study and Contingency Analysis

6.5.2.1 Transfer Limit Analysis

In order to assess new power transfer limits after the incorporation of new wind generation capacity and the assumed new 345 kV transmission line into the NSPI system as reinforcement requirement, the power transfer limits for the following interfaces are re-evaluated using the TLTG facility of the PSS/E software.

- Nova Scotia Export Limit

- CB Export

- Onslow Import.

TLTG activity is based on a linearized network model and does not consider reactive power requirements or voltage conditions. The power transfer limits for the defined interfaces were obtained solely based on the overloading criterion described in Section 6.2.2 and no generation rejection scheme is considered in the assessment.

The power transfer limit analysis was carried out on 2020 winter peak and summer peak load flow cases and the results are tabulated in Table 6-12.

Table 6-12: Interface Transfer Limit Assessments

Interfaces	Winter Peak (MW)	Summer Peak (MW)
NS Export	155	110 (135)[1]
CB Export	1375	1180
Onslow Import	1185	1160

1: Calculated limit is 135 MW

It is noted that the transfer limits calculated through TLTG and listed in Table 6-12 are higher than those described in Section 6.3.3. Although the thermal limit of Onslow-Springhill (L6513) is only 110 MVA in the summer, the calculated NS Export limit is 135 MW. This is because actual export flow level in the calculation includes the wind generation in the Springhill and Maccan areas.

However, the transfer limits shown in Table 6-12 may be considered preliminary until and unless these are further validated through stability simulations.

6.5.2.2 Contingency Analysis Results

The contingencies described under the revised contingency list were also applied on all four load flow base cases developed for the year 2020. These cases include specific assumptions on the amounts of new wind capacity for each zone and the contingency analysis results relate only to those situations.

The results of the analysis show that:

- No voltage violations occur and voltage levels are within the limits between 0.9 pu and 1.1 pu
- No overloading occurs for cases b1 and b2 for the loss of L8004b without requiring tripping of any unit on the system
- Onslow – Springhill 138 kV line experiences 18% overloading for the simultaneous loss (Contingency No b09) of L8001 and a single 345/230 kV transformer at Onslow. This is due to the additional wind power injection in the Truro zone at the 138 kV level
- Under winter peak conditions, NS transmission losses reduce by about 7 MW with the incorporation of wind farm generation as opposed to the case without the wind farm generation incorporated. With the proposed new 345 kV transmission line, total NS transmission losses are 24 MW less than without the new 345 kV transmission line.

A further load flow case under Summer Peak Load condition, with full dispatch of the wind power capacity injection of 920 MW, shows that there are no voltage and loading violations observed in the NSPI system.

6.5.3 Cost Estimate for the Identified Transmission Reinforcements

The budgetary cost estimates for the identified transmission reinforcements are given in Table 6-13.

Table 6-13: Cost Estimates for the Presumed Transmission Reinforcements

Item	Cost
Rights of Way	$ 11m
345 kV line	$ 172 m
Special Towers	$ 18 m
Substation at Port Hastings	$ 26.2 m
Substation at Halifax	$ 26 m
345 kV Line Reactors	$ 2 m
SVC (+100/-50MVAR)	$ 7 m
Total	$ 262.2 m

6.6 Intra-Province Transmission Congestion

As described in Section 6.3.3, the existing NSPI transmission system has a number of interface limits. In this preliminary assessment of additions of certain amounts of new wind power capacity by zone in 2013 and 2020, the following new transmission reinforcements are identified:

- By 2013, the breaker at Trenton on L6503 is rated at 1,200 Amps and needs to be replaced with breaker rated at 1,500 Amps
- By 2020, for one of the 781 MW of wind power capacity cases and both of the 981 cases, a 220 km, new 345 kV transmission line would be required from Port Hastings to Halifax, together with a SVC at Tufts Cove.

6.7 Potential Impacts on System Security

In this section, a brief discussion is presented to address the issues of reactive power capabilities, special protection system and generation scheduling.

6.7.1 Reactive Power Capability of Wind Facilities

The reactive power supply in a power system is very critical for power quality, system security and reliability. The existing Standard Generator Interconnection Procedures (GIP) is silent on the reactive power capability requirement of new wind generators. However, most other utilities require new wind facilities to provide reactive power capabilities similar to the conventional generation facility. We understand that Nova Scotia is following the same criterion in its interconnection feasibility study assessment. And thus it is assumed that the same principle will apply to the prospective wind generation facilities in Nova Scotia.

Some of the current wind turbine technologies do not meet the above requirements. Thus certain reactive compensation devices may be required within the wind facilities. This may include both dynamic compensation devices such as DVAR and switched shunt capacitors/reactors. The types and sizes of compensation devices can be determined during the System Impact Study phase.

6.7.2 Special Protection System

The Nova Scotia Power system has installed a SPSs at various locations. The primary purpose of SPS is to maximize pre-contingency power transfer levels across an interface and thus avoiding or postponing transmission investments. The addition of new wind facilities may affect those SPSs, depending on the sizes and locations of the wind facilities. The impact of integrating wind facilities on the existing SPSs should be determined during the System Impact Study phase. The existing SPSs may need to be re-designed and the new wind facilities may be required to be incorporated into the SPSs.

6.7.3 Generation Dispatch and Scheduling

Wind generation production is variable and can be subject to a high degree of uncertainty. This makes it more difficult to fit wind generation into the established procedures for power system operations and dispatch.

As the Nova Scotia system is relatively small, it is important to operate with a suitable combination of wind and conventional generation.

This is especially critical during light load conditions. Many of the conventional generating units may be shut down during light load conditions and wind generation could become a significant part of the on-line generation. Section 7 addresses the operating reserve requirements for different amounts of wind farm generation contributions in the system operation.

6.8 Assessment of the Adequacy of FERC ORDER 661/661A Low Voltage Ride-Through Capability

Wind Turbine LVRT capability is defined as the capability of a wind turbine to remain in service without tripping under reasonable low voltages following disturbances.

Different grid systems have different ride-through standards for wind turbines. Ontario Resource and Transmission Assessment Criteria (v.5) published by the IESO states:

- "Generator units do not trip for contingencies except those that remove generation by configuration. This requires adequate low and high voltage ride through capability. If generating units trip unnecessarily, they will require enhanced ride-through capability to prevent such tripping or the IESO may restrict operation to avoid these trips".

The IESO criteria requires wind turbines to be able to ride-through both high voltage and low voltages but it does not give specific voltage and time limits.

The WECC standard requires that generating plant must:

- have LVRT capability down to 15 percent of rated line voltage for the duration of the fault
- be able to remain in operation during the voltage swings specified in WECC Disturbance Performance Table (i.e., a 30% of transient voltage dip).

In 2005, the US Federal Energy Regulatory Commission (FERC) proposed standards (Post-transition Period LVRT Standard) requiring that a generating plant must:

- have LVRT capability during three phase faults within normal clearing (4 ~ 9 cycles) and single line to ground fault with delayed clearing, and subsequently post-fault voltage recovery to prefault voltage unless clearing the fault effectively

The FERC standard on LVRT is more stringent than the WECC standard as it requires wind turbines to stay on line for up to 9 cycles at a voltage as low as zero. The other differences are:

- WECC standards would apply to more units (10 MW or greater versus 20 MW or greater)

- WECC Standards apply to all generation and FERC's applies to wind generation.

When developing the standards for a wind turbine's LVRT capability, many factors need to be taken into account such as the nature of interconnected systems, system sizes and wind generation scale, etc.

The NSPI system is a relatively small system. According to its current plan, wind power will form an important part of generation in the coming years. In this study, some of the load flow cases are based on wind power generation of over 50% of the total generation required by the system at the time of the analysis. In such cases, mass tripping of wind turbines following disturbances will cause severe generation shortfalls and endanger the system stability. Thus, LVRT capability of wind turbines is especially important. It is recommended that NS develop a wind LVRT standard which is compatible with the FERC standard but can apply to both small and large wind farms in order to ensure system reliability and security.

7. Impact Analysis and Mitigation

7.1 Introduction

This section describes the analysis of the impacts of varying levels of increased wind generation capacity and the potential ways to mitigate the undesirable impacts. The impacts were estimated in terms of technical, economic and environmental aspects.

7.2 System Operational Variability

Power systems are dynamic and experience a continuously changing environment. They are impacted by many factors that change from time to time, i.e. second to second, minute to minute, hourly, daily, monthly, seasonally and year to year. In the various time frames of power system operation, balance between the system load and available generation must always be maintained. The impacts of wind power integration on the system operational variability can generally be assessed in three steps. The first step is to assess the operational variability of the system load by presuming that there is no new wind power in the system (load minus the existing wind power generation). The next step is to assess the operational variability of the system load minus total wind power generation. The impacts of integration of new wind power on system operational variability will be the difference between the values calculated in the second step and the first step (the values calculated based on the load minus wind less the values calculated based on the load). Statistics is a very useful tool for assessment of system operational variability.

The operational variability assessed in this study includes the following:

(1) Maximum daily load minus wind variation, which is the maximum difference between the highest and lowest hourly load minus wind values of a day within one year

(2) Standard deviation of 3-hour load minus wind ramps, in which the average load minus wind values within every three hours are used

(3) Standard deviation of 1-hour load minus wind ramps, in which the hourly load minus wind values are used

(4) Maximum hourly load minus wind variation, which is the maximum difference between the highest and lowest 1-minute load minus wind values of an hour within one year

(5) Standard deviation of 10-minute load minus wind variations, in which the average load minus wind values within every 10 minutes are used

(6) 10-minute load following requirement (three times the standard deviation of 10-minute load minus wind variations)

(7) Standard deviation of 5-minute load minus wind variations, in which the average load minus wind values within every five minutes are used

(8) Standard deviation of 1-minute load minus wind variation

(9) Automatic generation control requirement (three times the standard deviation of 1-minute load minus wind variations).

As per the discussions presented in Sections 2 and 3 on the reserve sharing protocols with other Maritime utilities and the Nova Scotia DSM programs, NSPI and Hatch agreed that for the purpose of system simulation using the *Vista* model, the following requirements need to be met at all times:

(1) The amount of spinning reserve capacity determined by the reserve sharing protocols;

(2) The AGC requirement calculated from 1-minute load minus wind variations (three times the standard deviation of the 1-minute load minus wind variations)

(3) The 10-minute load following requirement calculated from 10-minute load minus wind variations (three times the standard deviation of the 10-minute load minus wind variations). It was further agreed that the capacity required for the 10-minute load following requirement includes the AGC requirement

(4) Other operating reserve requirements (such as 10-minute non-synchronized and 30-minute reserve requirements) will be met through quick-start generating units, hydroelectric generating units if applicable, interruption to industrial loads and other mechanisms.

To avoid any confusion in understanding the items listed above, these requirements could be interpreted as the total on-line and synchronized capacity reserve at any time being equal to or larger than the sum of spinning reserve requirement and 10-minute load following requirement. The requirements for AGC and 10-minute load following service have been calculated separately as it is understood that the generating facilities providing AGC service may have different requirements from the generating facilities providing 10-minute load following service.

Hatch has developed a prototype Excel based macro model to evaluate the variation rate of load, load minus wind and wind power generation, and the distribution of the variations (histogram). The variations can be analyzed by either the difference between the two consecutive averages within two specified time periods or the difference between the maximum and minimum values within one specified time period.

Based on the 2005 zonal one-minute load data files provided by NSPI, Hatch has created the zonal one-minute data files for 2008, 2010, 2013 and 2020 as per the forecast annual peak and energy demands which have been summarized in Section 2 of this report. In evaluation of system operational variability such as AGC and load following requirements, Hatch has carried out this task in two presumed cases, (1) system load with the existing 61 MW wind generation only, and (2) system load with both existing and presumed new wind generation projects. The difference between the two calculated values for each year would be the incremental requirements due to the integration of new wind power generation into the system.

Hatch has assessed the annual operational variability for the postulated wind capacity addition cases, among which AGC and load following requirements are used as input to *Vista* optimization.

7.2.1 Base Plan

To understand the impact of wind power on system operational variability, Hatch has created several graphs and tables to study the contribution of wind power generation to the system. Some of these are presented in this subsection based on the system conditions in 2020.

Figure 7-1 presents a scatter diagram illustrating the distribution of hourly wind power output (% of rated capacity) against the system load levels (% of annual peak) when the system has a total of 581 MW of wind power generation. It can be seen from this figure that the area surrounded by load levels between 55% and 70% and wind power output levels between 10% and 50% has a higher distribution density of points, i.e. there will be more chances for wind generating plants to produce between 10% and 50% of their rated power when the system experiences between 55% and 70% of its annual peak load. As illustrated in Figure 7-2, the system will experience 2,784 hours of load ranging between 60% and 70% of system annual peak.

The histogram presented in Figure 7-2 also shows the occurrence frequency (total number of hours) of various wind power generation levels versus the system load levels (% of annual peak). At a given load level, the sum of the stacked bars shows the occurrence frequency of this load level within one year while each of these stacked bars shows the occurrence frequency of the wind power generation level at this load level. For example, it shows that the system will experience a total of 2784 hours of load ranging between 60% and 70% of the system annual peak. Among these hours, there will be no chance for wind power at less than 1% level, 603 hours of wind power ranging between 1% and 20%, 880 hours of wind power ranging between 20% and 40%, 676 hours of wind power ranging between 40% and 60%, 411 hours of wind power ranging between 60% and 80% and 214 hours of wind power ranging between 80% and 100%.

Figure 7-3 presents a histogram showing the relative contribution of various wind power generation levels at a given system load level (% of annual peak), which is created based on the results presented in Figure 7-2. In this figure, the total number of occurrence frequency at each given load level is considered as 100%. This means that each set of stacked bars shows the relative contribution of wind power generation at a given load level. It can be seen from this figure that the contribution of wind power generation (generation over 60% of its rated output) increases as the system load increases. This can also be explained using the numbers used in explanations for Figure 7-2. Figure 7-2 shows that the system will experience a total of 2,784 hours of load ranging between 60% and 70% of its annual peak. With 214 hours of wind power ranging between 80% and 100%, it could be interpreted that at this given load level, the system will have some 7.7% (214/2784*100=7.7%) probability with wind power generation ranging between 80% and 100%. The value of 7.7% is represented by the top bar of the 60% to 70% load level in Figure 7-3.

Table 7-1 presents an overall summary of operational variability for four milestone years, 2008, 2010, 2013 and 2020 of the Base Plan. In 2008, the total installed wind capacity will be some 61 MW. By 2010, it is considered that the system will have a total of some 311 MW under two different installation options. The difference between 2010 and 2008 wind power installations, i.e. 250 MW of new wind power capacity, is based on the submissions received by NSPI from its 2007 Renewable Energy RFP. In the first option, 40, 50, 60 and 100 MW of new wind power capacity are allocated in the Valley, Truro, Pictou and Canso Strait zones respectively. In the other option, 40, 80, 120 and 10 MW of new wind power capacity are allocated to the Valley, Truro, Pictou and Canso Strait zones respectively. By 2013, it is considered that the system will have a total of 581 MW of wind power capacity. In the Base Plan, it is presumed that there will be no more additions of wind power generation capacity from 2013 and onward.

The incremental impact of addition of new wind power plants on system operational variability is calculated based on the difference of system operational variability at two different levels of wind power integration. It can be seen from Table 7-1 that at the 2020 load level, the system would need only 16.3 MW of AGC if the total wind power was kept at the current level of 61 MW. This requirement would be increased to 37.9 MW when the total wind power capacity is increased to 581 MW. The resulting incremental increase in AGC requirement is 21.6 MW, or 132.2% (comparing with the value of 16.3 MW).

Similar explanation is also applicable to the 10-minute load following requirement. In the case of 61 MW of wind power generation, the system would need 54.8 MW 10-minute load following capability in 2020. This requirement would be increased to 91.7 MW when the total wind power capacity is increased to 581 MW. The difference between the two values is 36.8 MW, i.e. an increase of 67.2% (comparing with the value 54.8 MW).

In order to understand further the increased requirements on AGC and 10-minute load following capability, Figure 7-4 and Figure 7-5 present the 1-minute and 10-minute load variation frequency as per the 2020 load level and integration of 581 MW of wind power capacity. In these two figures, the Legend "Load" represents the system load less the 61 MW existing wind power generation. The Legend "Load-Wind" means the system load less the 581 MW of wind power capacity (61 MW existing and 520 MW new wind power). It can be seen from these two figures that the occurrence frequency corresponding to the "Load-Wind" variations is much more widely dispersed than that corresponding to the "Load" variations. This also means that the "Load-Wind" variations would have a higher standard deviation than the "Load" variations.

There are a total of 525,599 (8760*60-1) 1-minute load variations within one year. It can be calculated that in Figure 7-4, the "Load" histogram shows a total of 479,656 (479656/525599*100=91.26%) occurrences within the range of ±6 MW (comparing to the 5.4 MW standard deviation of the "Load" variations) while the "Load-Wind" histogram shows only a total of 319,502 (319502/525599*100=60.79%) occurrences within the same range. By increasing the range to ±13 MW (comparing to the 12.6 MW standard deviation of the "Load-Wind" variations), the "Load-Wind" histogram shows a total of 447,428 (447428/525599*100=85.13%) occurrences. The similar explanations can also be applied to Figure 7-5.

The occurrence frequency of load variations shown in Figure 7-4 and Figure 7-5 can be summarized as follows:

Interval	Range (MW)	Load Frequency	Load-Wind Frequency	Range (MW)	Load-Wind Frequency
1-Minute	± 6	479,656	319,502	± 13	447,428
	% of Coverage	91.26	60.79		85.13
10-Minute	± 20	42,582	30,795	± 30	39,072
	% of Coverage	81.02	58.59		74.34

The operational variability of 581 MW wind power integration in 2020 was also analyzed using a moving window methodology to examine the impact of wind timing on system operational requirements such as AGC and load following. In this approach, the wind power generation pattern over an entire year was moved backward by one day in a step of two hours, i.e. the occurring of wind was delayed by one day in a step of two hours. The study results are presented in Table 7-2.

The following findings can be observed from the moving window analysis results:

(1) The maximum and minimum standard deviations of the 3-hour Load minus Wind variations are 202.5 MW and 182.9 MW, with a difference of 19.6 MW

(2) The maximum and minimum standard deviations of the 1-hour Load minus Wind variations are 91.3 MW and 85.3 MW, with a difference of 6 MW

(3) The difference between the maximum (31.1 MW) and minimum (30.6 MW) standard deviations of the 10-minute Load minus Wind variations is only 0.5 MW

(4) The standard deviation of the 1-minute Load minus Wind variations is almost constant, some 12.6 MW.

These findings imply that delay of the wind power pattern over one entire year by two to 24 hours will not have significant impact on system 10-minute load following and AGC requirements but could have some impact on system day ahead unit scheduling or two-hour dispatch day analysis.

7.2.2 Alternative Plans

As described in Subsections 3.4 and 3.5, in addition to the Base Plan, Hatch has also developed two other wind integration plans to study the impact of different levels of wind power integration, i.e. Alternative 1 Plan and Alternative 2 Plan.

In Alternative 1 Plan, two options are considered, each with a total wind power capacity of 781 MW (720 MW new additions) by 2020. The differences between the two options are the zonal allocation of potential wind plants and the requirement of a new 345 kV transmission line. The detailed allocations of wind power for this plan have been described in Subsection 3.5.

Alternative 2 Plan also has two options for wind power integration, each with a total of 981 MW (920 MW new additions) by 2020. The difference between the two options is only the zonal allocation of new wind plants.

Figure 7-6 presents the histogram of occurrence frequency of 781 MW wind power generation and Figure 7-7 presents the histogram of relative generation contribution of 781 MW wind power generation for Option 1 of the Alternative 1 Plan. Similar pairs, Figure 7-8 and Figure 7-9, Figure 7-10 and Figure 7-11, and Figure 7-12 and Figure 7-13 are for Option 2 of the Alternative 1 Plan, Option 1 of the Alternative 2 Plan and Option 2 of the Alternative 2 Plan.

The explanations for the eight histograms are similar to those for Figure 7-2 and Figure 7-3, which are based on a total of 581 MW of wind power in 2020.

Table 7-3 presents the operational variability for Year 2020, which includes several levels of wind power integration. It can be seen from this table that it has eight columns of study results, among which the first four columns are the same as those provided for the Base Plan in Table 7-1. The results under the two 781 MW columns are for the two options of the Alternative 1 Plan while the results under the last two columns are for the two options of the Alternative 2 Plan.

As seen from this table, the first option of the Alternative 1 Plan would require 57 MW AGC and 123.4 MW 10-minute load following capability. The other option would need only 45 MW AGC and 105.9 MW 10-minute load following capability. The reasons for the relatively large differences between the two options are (a) the diversity of wind plants, (b) the zonal wind power productivity and (c) the coincidence between load and wind power.

It can also be seen from Table 7-3 that for the two options of the Alternative 2 Plan, have very similar requirements for AGC and 10-minute load following capability. By checking the zonal allocation of wind power plants of these two options, one can quickly find that only two of the six zones have different amounts of wind power and the difference for each zone is only 50 MW.

Figure 7-14 to Figure 7-21 present eight histogram graphs showing the occurrence frequency of load variations in 2020. Every two graphs, one for 1-minute load variation and the other for 10-minute load variation, are for one option of the two Alternative Plans. As explained before, in these graphs, the Legend "Load" represents the system load less the 61 MW existing wind power generation. The Legend "Load-Wind" means the system load less all wind power generation.

The table below summarizes the occurrence frequency of load variations for the first wind power development option (781 MW wind power) of the Alternative 1 Plan. These results were calculated using the same sets of data as those used in creation of Figure 7-14 and Figure 7-15.

Interval	Range (MW)	Load Frequency	Load-Wind Frequency	Range (MW)	Load-Wind Frequency
1-Minute	± 6	479,656	268,282	± 19	456,193
	% of Coverage	91.26	51.04		86.79
10-Minute	± 20	42,582	25,817	± 40	39,526
	% of Coverage	81.02	49.12		75.20

It can be seen from the table above that 91.26% of 1-minute load variations will be within the range of $\pm$6 MW (standard deviation of 5.4 MW) if the system has only 61 MW of wind power. Only some 51% of the 1-minute load variations will be within this range if the system has a total of 781 MW of wind generation capacity. When the range is increased to $\pm$19 MW (standard deviation of 19 MW), the coverage will be increased to 86.79%.

It can also be seen that 81.02% of 10-minute load variations will be within the range of $\pm$20 MW (standard deviation of 18.3 MW) if there is only 61 MW of wind power in the system. When the wind power generation capacity is increased to 781 MW, this range can only cover 49.12% of 10-minute variations. 75.2% of 10-minute load variations will be within the range of $\pm$40 MW (standard deviation of 41.1 MW).

The table below can be used to understand the two histogram graphs presented in Figure 7-16 and Figure 7-17, which are for the second option (781 MW wind power) of the Alternative 1 Plan. In this case, the system has also a total 781 MW of wind power generation capacity and the calculated standard deviation is 15 MW for the 1-minute load variations, and 35.3 MW for the 10-minute load variation.

Interval	Range (MW)	Load Frequency	Load-Wind Frequency	Range (MW)	Load-Wind Frequency
1-Minute	± 6	479,656	279,166	± 15	439,537
	% of Coverage	91.26	53.11		83.63
10-Minute	± 20	42,582	27,756	± 35	39,263
	% of Coverage	81.02	52.81		74.70

It is generally expected that the more wind power an electric system has, the more load minus wind variations the system will experience. The table below summarizes the study results graphed in Figure 7-18 and Figure 7-19, which are for the first option (981 MW wind power) of the Alternative 2 Plan. The standard deviation of the load minus wind variations is 21.1 MW for the 1-minute data set, 46.1 MW for the 10-minute data set.

Interval	Range (MW)	Load Frequency	Load-Wind Frequency	Range (MW)	Load-Wind Frequency
1-Minute	± 6	479,656	239,648	± 20	445,291
	% of Coverage	91.26	45.60		84.72
10-Minute	± 20	42,582	23,445	± 45	39,369
	% of Coverage	81.02	44.61		74.90

The study results depicted in Figure 7-20 and Figure 7-21 are summarized in the table below, which are for the second option (981 MW wind power) of the Alternative 2 Plan. The standard deviation of the load minus wind variations is 20.7 MW for the 1-minute load minus wind ramps, and 44.8 MW for the 10-minute load minus wind ramps.

Interval	Range (MW)	Load	Load-Wind	Range (MW)	Load-Wind Frequency
		Frequency			
1-Minute	± 6	479,656	238,405	± 20	446,764
	% of Coverage	91.26	45.36		85.00
10-Minute	± 20	42,582	23,556	± 45	39,768
	% of Coverage	81.02	44.82		75.66

7.3 Impact on GHG and Other Air Emissions

Hatch has carried out detailed generation system dispatch analysis using our proprietary software package *Vista*. The years simulated include 2008, 2010, 2013 and 2020. The primary purposes of the *Vista* simulations are as follows:

(1) Examining the dispatching capability of the NSPI generation fleet

(2) Projecting the energy output of each generating unit/plant

(3) Projecting the ancillary services including spinning reserve and load following to be provided by each generating unit/plant

(4) Computing the fuel consumptions and costs of thermal generating units/plants

(5) Estimating potential interruptions to interruptible loads or firm load

(6) Examining the congestion of major intra-province transmission circuits.

The annual GHG (CO_2) and other air (SO_2, NO_x and Hg) emissions were estimated using the emission intensities of each thermal unit and the fuel consumption projected by the *Vista* model. As there are only the existing wind power plants in 2008 and there is no other case to compare, this section presents only estimated emissions and emission reductions for 2010, 2013 and 2020, which are shown in Table 7-4 to Table 7-6 respectively.

As seen from Table 7-4, the estimated CO_2 emission in 2010 will be higher than the established cap of 10,000 kilo-tonne regardless of which of the two 250 MW new wind power generation options is implemented before 2010. The first option would result in reductions of some 607 kilo-tonne of CO_2 emissions while the second would result in reductions of some 550 kilo-tonne. In order to meet the established cap requirement, the system may need to change its normal economic operation policies and procedures to increase energy generation from units with lower CO_2 emission rates and reduce energy generation from units with higher CO_2 emission rates. This would of course be expected to increase total system costs. Both of the two options will meet the annual emission caps on SO_2, NO_x and Hg.

As seen from Table 7-5, installation of a total of 520 MW of new wind power capacity by 2013 would bring all emissions below their established caps in 2013. The 520 MW of new wind power capacity would reduce CO_2 emissions by some 1,278 kilo-tonne.

It can be seen from Table 7-6 that installation of 250 MW of new wind power capacity by 2020 can not meet the established cap requirements for SO_2, NO_x and Hg emissions. Installation of 520 MW of new wind power capacity would allow all emission cap requirements to be met except for that for NO_x emissions, which amount to 14.904 kilo-tonne a figure slightly higher than the established cap of 14.7 kilo-tonne. The difference of some 204 tonne of NO_x emissions above the established cap should be manageable by adopting one or combinations of, the following approaches:

(1) Increasing the energy generation from low NOx emission generating units

(2) Burning more fuels with low NOx emission for the generating units with fuel switch capability

(3) Installing NOx emission mitigation technologies on generating units.

If integration of new wind power generation capacity could be more than 520 MW by 2020, the generation system would meet all established emission cap requirements. It is understandable that in these cases more energy would be supplied by wind power plants.

7.4 Estimation of the Avoided Cost of GHG Emissions

NSPI included only CO_2 offset costs in its 2007 IRP analysis. For other air emissions such as SO_2, NO_x and Hg, the adopted approach is to maintain the levels below the established emission caps but to not assess costs against the emissions quantities. Thus only the estimated avoided cost of GHG emissions are presented in this section.

Table 7-4 to Table 7-6 have presented the impact of different wind power integration levels on expected CO_2, SO_2, NO_x and Hg emissions. These tables have also presented the environmental benefits of CO_2 emission reductions when compared with the base case with only the existing wind power plants. Based on the CO_2 offset costs provided by NSPI, the estimated avoided costs due to reduced GHG emissions due to integration of wind power were calculated and are presented in Table 7-7.

It can be seen from Table 7-7 that the estimated avoided cost of GHG emissions in 2010 will be in the range $8.3 to $9.1 million when the system has a total of 311 MW of wind power capacity installed. When the installed wind power capacity is increased to a total of 581 MW by 2013, the estimated avoided cost of GHG emissions will be some $28.6 million.

Based on the assumptions used and the procedures followed, it is generally true that larger GHG emission reductions will be achieved when more wind power capacity is integrated to the system to displace the energy that would be produced by the units/plants with higher GHG emission rates. In 2020, the CO_2 offset price is assumed to be $38.76/Tonne. One can find from Table 7-7 that the avoided cost of GHG emissions in 2020 varies from some $21.6 to $102.9 million depending on the wind power capacity installed and the zonal allocation of wind power. If by 2020 no more than the total of 581 MW of wind power capacity that is expected to be needed to meet the RES 2013 requirement is installed, the avoided cost of GHG emissions will be some $50.4 million in 2020.

7.5 Cost Impact of the Adequacy Impacts

As seen from Table 3-2 to Table 3-4 presented in Section 3, it is expected that only minor additions and upgrades will be made to the NSPI generation fleet over the period from 2008 to 2020 in addition to the planned wind generation to meet RES 2013. The planned additions and upgrades will have the same fixed costs including amortized annual capital payment and fixed O&M costs for the various study cases. The annual cost of potential wind power integration is calculated as the product of wind energy production (MWh) and the projected wind energy purchase price/production cost in $/MWh.

Based on these assumptions and facts, it is understandable that the capital cost of new generation facilities will not have differential impacts on the total system costs for various levels of wind power integration.

7.5.1 Cost Impact on Operating Reserve, AGC and Load Following Requirements

As per the explanations given in Section 3.3, the NSPI system needs to carry 32 MW of spinning reserve, 140 MW of 10-minute quick start reserve and 70 MW of 30-minute reserve in its daily operation. The AGC and 10-minute load following requirements for different wind integration levels by year have been presented in Table 7-1 and Table 7-3.

It has been agreed with NSPI that for the *Vista* simulations, the total synchronized capacity reserve that the system needs to carry is the sum of predetermined spinning reserve (32 MW) and the amount calculated for the 10-minute load following requirement (this element varies from one wind power integration case to another). It is further assumed that the AGC capacity requirement is part of the 10-minute load following requirement and AGC capacity should be maintained at or above the calculated value.

The costs, including variable O&M cost and fuel costs, of operating reserve, AGC and load following requirements is part of the total system operation cost in the *Vista* simulations. However, it is very difficult to segregate these costs from the other system operation costs. The total system cost for each simulation case will be discussed in Section 7.6.

7.5.2 Cost Impact on Unit Commitment and Water Allocation Decision Making for System Balancing

As explained and described in Section 5, the *Vista* model optimizes weekly system operation by taking into consideration various constraints such as hourly load demand at each bus, available generation at each bus, fuel cost of generating units, system operating reserve, transfer capability of transmission lines, etc. Similar to the explanations given in the previous subsection, the cost of unit commitment and water allocation is also part of the total system cost and therefore it is very difficult to separate these cost elements from other system costs.

7.5.3 Cost Impact on Intra-province Transmission

This preliminary assessment study assumed a cluster of wind generations in each zone that were incorporated into a single node within that zone. Actual wind facilities may be installed at a number of locations within a zone and will be connected to the NSPI transmission system at different voltage levels. It should be noted that the cost estimates presented in this report do not include the costs associated with specific generation interconnections, which may typically include a tap line and local transmission/distribution system upgrading costs. These costs could be determined during the System Impact Assessment phase.

As described in Section 6, the existing circuit breaker rated at 1,200 Amps at the Trenton station would be required to be replaced by a new breaker with a rating of 1,500 Amps in order to integrate 581 MW of wind power. The estimated cost for this is some $200,000.

In order to evacuate more power from the Canso Strait and Sydney zones, load flow analysis identified that a new 345 kV transmission would be required to be built, which would run from the Canso Strait bus to the Metro bus. It has been estimated that the new line would cost some $262.2 million. This new line would be required, under the assumptions made for the zonal distribution of new wind power capacity, for one of the 781 MW cases (Option 1) and both of the 981 MW cases.

7.6 System Generation and Cost Summary

It is emphasized that the system costs presented in this study include the following:

(1) Amortized annual capital payment for planned generation additions and upgrades such as conversion of two Tuft's Cove gas turbines into a combined cycle configuration, installation of low NO_x burners on coal units, installation of FGD equipment on two Lingan coal fired units, addition of small hydro units/plants (Marsh and Nictaux), etc.

(2) Annual fixed O&M costs for existing generation projects, planned generation addition and upgrade projects

(3) Fuel costs for all thermal units

(4) Wind purchase/production costs

(5) Start-up costs of steam turbine driven units

(6) Annual variable O&M costs

(7) Cost penalty for both interrupted and unserved energy computed by the *Vista* model

(8) Amortized annual capital cost payment and fixed O&M cost of new transmission line and transmission reinforcements

(9) CO_2 offset costs.

At the same time, it is also important to note that the system costs presented in this study do not include the following:

(1) Costs associated with purchasing power from the bio-mass plant

(2) Capital costs of existing generation and transmission facilities as they are common to all wind power integration levels

(3) Annual fixed O&M costs of existing transmission facilities

(4) Amortized annual costs of DSM programs

(5) Amortized annual capital payment of incremental AGC and load following capacity as there are no new generating units added for these purposes over the study period

(6) Natural gas not available

(7) Additional planned outages of thermal/hydro units due to cycling

(8) Water issues at thermal power plants

(9) Ramp times on Thermal Units

(10) Intra 2 hour regulation requirement

(11) Perfect day ahead forecasting

(12) Less than 100% success on starts

(13) Plant investments to allow cycling

(14) Support energy at low loads/cycling

(15) Plant loss of fly ash sales

(16) Noise/environmental problems at plants re cycling

(17) Other operating costs that can not be simulated by the *Vista* model. A few of the potential causes are (a) forecasting uncertainty of load demand and wind, (b) random outage of generation and transmission facilities, (c) sudden weather changes and adverse weather conditions, and (d) tie-line imbalance.

It should be emphasized that the information used and/or assumptions made for the various technical and economic parameters used in the analysis could have significant impacts on system costs or even result in different conclusions. Some of the technical parameters include:

(1) Future load demand time series patterns

(2) Future DSM achievements

(3) Future interruptible loads

(4) Minimum loading requirement of generating units

(5) Minimum loading requirement of units to provide AGC, load following and spinning reserve services

(6) Heat rate of thermal units

(7) Cycling capability of thermal units

(8) The volume of reservoirs and associated rule curves

(9) Outage schedules of generating units and major transmission lines

(10) Expected zonal wind power capacity factors

(11) Zonal wind power generation time series patterns

(12) Zonal wind power capacity allocations.

Some of the economic parameters include:

(1) Wind energy prices

(2) Forecast fuel prices of thermal units

(3) Start-up costs of steam turbine driven units

(4) Start-up energy production of steam turbine driven units

(5) Forecast variable O&M costs of generating units

(6) Capital costs and fixed O&M costs of new generation projects

(7) Capital costs and O&M costs of new transmission facilities including both upgrades and additions

(8) Expected life of new projects

(9) Cost escalation rate

(10) Discount rate.

7.6.1 Generation and Cost Summary Information in 2010

Energy generation summary information in 2010 is presented in Table 7-8, which includes two wind power capacity levels, 61 MW and 311 MW. One can quickly find that this table presents energy generation for each category of units/fuel in both GWh and percentage terms. It can be seen from this table that either of the two 311 MW wind power integration options would produce some 907 GWh or more of post 2001 renewable energy or some 6.8% or more of annual energy production, which will meet/exceed the RES 2010 requirement. The total renewable energy generation will amount to some 2090 GWh or more, i.e. 15.6% or more of annual energy production.

This table also presents total system costs for the three wind power capacity integration cases. It is very interesting to note that the total estimated system costs for the two 311 MW wind power integration options are very close at some $728 million, which is slightly lower than the $728.9 million estimated for the business as usual case (with only the existing 61 MW of wind power capacity) when the CO_2 offset costs are included. The business as usual case is shown to have lower system costs when the CO_2 offset costs are excluded from the total system costs.

This table also presents the benefits of new wind energy expressed in $/MWh, which is calculated based on the incremental system costs relative to those of the business as usual case and the incremental generation by wind power units. Positive numbers indicate a benefit of new wind power to the system after paying wind power generators at the presumed rates. Negative numbers indicate there would be an additional cost of new wind power to the system.

7.6.2 Generation and Cost Summary Information in 2013

Table 7-9 presents energy generation summary information in 2013 for two wind power integration levels, 61 MW and 581 MW. One can find from this table that the system would produce some 1,770 GWh of post 2001 renewable energy or 13.2% of annual energy generation when the system has a total of 581 of MW wind power generation plants. This will increase the total renewable energy to some 2,950 GWh or some 22.1% of annual energy generation.

When accounting for CO_2 offset costs, the system costs would be some $901.1 million for the 581 of MW wind power integration case, which is almost equal to the system costs of $900.7 million for the business as usual case, i.e. only the existing 61 MW of wind power plants. The case with 581 MW of wind power would cost some $30 million more than the business as usual case if the CO_2 offset costs are excluded.

7.6.3 Generation and Cost Summary Information in 2020

Table 7-10 presents the energy generation summary in 2020 for the five wind power integration levels studied - 61 MW, 311 MW, 581 MW, 781 MW and 981 MW. As explained before, each of the three integration levels, 311 MW, 781 MW and 981 MW has two options for allocation of the presumed wind power plants to individual zones.

The following findings can be observed from Table 7-10:

(1) With integration of 311 MW of wind power, the system would produce at least 907 GWh of post 2001 renewable energy or more than 6.9% of annual energy production. The total renewable energy would account for more than 15.9% of annual energy production

(2) If technically feasible, installation of 581 MW of wind power capacity would produce some 1,770 GWh of post 2001 renewable energy or about 13.5% of annual energy production. The total renewable energy would amount to 2,943 GWh or 22.5% of total energy production

(3) If technically feasible, installation of 781 MW of wind power capacity would produce at least 2,386 GWh of post 2001 renewable energy or about 18.2% of annual energy production. The total renewable energy would be at least 3,556 GWh or 27.2%. It is important to note that in this calculation, wind power curtailment is not considered

(4) If technically feasible, installation of 981 MW of wind power capacity would produce at least 3,132 GWh of post 2001 renewable energy or about 24% of annual energy production. The total renewable energy would amount to at least 4,278 GWh or 32.7%. It should be emphasized that wind power curtailment is not considered in this calculation.

Table 7-10 also presents total system costs in two different ways, with and without accounting for CO_2 offset costs. For easy reference and explanation, only the values associated with total system costs, i.e. with accounting for CO_2 offset costs are used in this subsection. The following can be observed from Table 7-10:

(1) The business as usual case would have total system costs of some $1,247 million

(2) The total system costs of the two 311 MW wind power capacity options range from some $1,201 to $1,207 million. The difference between the two options is some $6 million

(3) Installation of 581 MW of wind power capacity would result in a total system cost of some 1,197 million

(4) The two 781 MW wind power capacity options would have total system costs ranging from $1,224 to $1,293 million. System costs include annualized capital payments for the specified new 345 kV transmission line for Option 1 as this option would require this line

(5) With a total of 981 MW wind power capacity in the system, the system costs would range from $1,366 to $1,374 million. Both of the two values include annualized capital payments for the above mentioned new transmission line

(6) It can be concluded that the lowest system costs correspond to total wind power capacity ranging from 311 MW to 581 MW.

It is important to point out that the total system costs assessed for the business as usual cases (61 MW of wind power capacity) in 2010, 2013 and 2020 could be reduced by installing new conventional generating units/plants. It can be calculated from Table 3-2 to Table 3-4 that the total available generation capacity would be some 2,360 MW by 2010, 2,370 MW by 2013 and 2,362 MW by 2020 in these business as usual cases have no new wind power plants integrated into the system. These three values are less than the firm capacity requirements of 2,371 MW in 2010, 2,399 MW in 2013 and 2,406 MW in 2020, which were calculated based on system firm peak demands. As the total loads used in the *Vista* simulations included interruptible loads and these interruptible loads would not be curtailed for economic reasons, it is believed that additional conventional generation resources would reduce the total system costs by balancing load and supply. However this exercise is outside the scope of this study and would also be somewhat academic in view of the need for achievement of the 2010 and 2013 RES and the associated plans for installation of wind power capacity. Thus components to the "business as usual" (61 MW of wind power capacity) cases for 2010, 2013 and 2020 should be made with caution.

Similarly, addition of quick start generating units with capability to provide AGC and load following services could also potentially reduce the system costs of cases with high levels of wind power integration.

7.6.4 System Costs and GHG Impacts of Wind Generation Capacity Addition

Based on the cost summary information presented in Table 7-10 and the emissions summary information presented in Table 7-6 and Table 7-7, Figure 7-22 and Figure 7-23 are presented to show the system costs and GHG impacts as a function of installed wind generation capacity. Figure 7-24 shows the relationship between total system costs and CO_2 emissions reduction. It is important to note the following:

(1) The system costs and GHG emissions presented in the three figures are for 2020 only;

(2) The costs and GHG emissions presented in the two figures are associated with the second options for wind power integration levels of 311 MW, 781 MW and 981 MW. The second option of the 311 MW wind power capacity case has the best representation of the expected outcomes of the NSPI 2007 Renewable Energy RFP. The second option of the 781 MW wind power capacity case does not require the specified new transmission line. Once the second option of the 781 MW wind power case is adopted, addition of another 200 MW of wind power will result in the second option of the 981 MW wind power installation case.

(3) The system costs presented in Figure 7-22 include CO_2 offset costs while the system costs presented in Figure 7-23 do not

(4) The system costs presented in Figure 7-24 include CO_2 offset costs.

7.7 Impact of Wind Energy Prices on System Costs

The preliminary study results were presented to the project Advisory Committee via teleconference on February 8, 2008. After discussions, the Advisory Committee suggested that sensitivity studies be carried out using a range of wind energy prices to examine the impacts of wind power capacity addition cases on system costs. The wind energy prices suggested for this analysis are $70, $80, $100 and $120 per MWh. It is worth noting that these prices are based on 2007 cost levels and that a single wind energy price is applied to all wind power projects in a case.

Table 7-11 to Table 7-13 present the sensitivity study results to different wind energy prices for the years 2010, 2013 and 2020.

One can find from Table 7-11 that at the wind energy price of $80/MWh, installation of 250 MW of new wind power capacity would reduce the system costs by approximately five million dollars in 2010 when CO_2 offset costs are included. If the wind energy price is increased to $100/MWh, integration of the same amount of wind power will cost some $10 million more, compared with the system costs of the corresponding business as usual case.

It can be seen from Table 7-12 that at the wind energy price of $80/MWh, installation of 520 MW of new wind power capacity would reduce the system costs by approximately four million dollars in 2013 when the CO_2 offset costs are included. Comparing with the business as usual case, the system costs would be increased by $32 million when the wind energy price is increased to $100/MWh.

One can find from Table 7-13 that at the wind energy price of $80/MWh, installation of 520 MW of new wind power capacity would reduce the system costs to some $1192.0 million from some 1245.9 in 2020, a cost reduction of $53.9 million when accounting for CO_2 offset costs. If the wind energy price is increased to $100/MWh, the saving is reduced to some $18.7 million, comparing with the case with the existing wind power generation capacity only. It should be emphasized that the CO_2 offset price in 2020 has been presumed as $38.76/Tonne, comparing with $15.06/Tonne in 2010 and $22.40/Tonne in 2013.

7.8 Impact of the Size of Combined Cycle Unit on System Costs

In the NSPI 2007 IRP, it was planned that the two Tufts Cove 50 MW gas turbines (GTs) would be converted to a 150 MW combined cycle (CC) unit by 2010. After consultation with the Advisory Committee and NSPI, NSPI requested that this study be based on the conversion of the two GTs into a 125 MW CC unit, a reduction of 25 MW in capacity. At the same time, NSPI requested sensitivity analysis on the size of the CC unit for one or two cases (years). In response, Hatch carried out the sensitivity study for the 150 MW CC unit size for the second option of the 311 MW of wind power capacity addition in 2013 and the case of installation of a total of 581 MW of wind power capacity by 2013. The summary of energy generation and system costs for the sensitivity study is presented in Table 7-14.

One can find from this table that conversion of the two GTs into a CC 150 MW unit versus a CC 125 MW unit would reduce system costs to some $723.4 million from some $728.1 million in 2010, i.e. a potential saving of some $4.7 million in that year. The CC 150 MW unit would reduce the system costs by some $5.6 million in 2013 when the system has a total of 581 MW of wind power projects installed.

In addition to the economic benefits, the CC 150 MW unit option would also reduce annual CO_2, SO_2, NO_x and Hg emissions slightly.

7.9 Sensitivity of Impacts to Project Size and Location

As per the study RFP requirements and for purposes of the analysis, the province of Nova Scotia is divided into seven zones, Sydney, Canso Strait, Pictou, Truro, Metro, West and Valley. As limited interest has been shown in the development of new wind power projects in the Metro zone based on the NSPI's interconnection application queue, it is assumed that all new wind generation projects will be located in the remaining six zones.

In order to carry out a generic assessment of the sensitivity to project size/concentration and location, Hatch carried out a diversity/concentration analysis based on a total of 600 MW of new wind power generation. The 600 MW was picked for convenience to allow each of the six zones to be analyzed with 100 MW of wind capacity. When only one zone is selected, all 600 MW of new wind power projects are located in one single zone (pre-determined). In comparison, each zone is allocated with 100 MW of new wind power projects if all six zones are selected. The selection order of the six zones is as follows:

(1) Pictou

(2) Truro

(3) Canso Strait

(4) Sydney

(5) Valley

(6) West.

In order to understand the impact of wind power diversity on system operational variability, several graphs were created taking into account the load conditions in 2020. Figure 7-25 shows the scatter diagram of wind power generation in the West zone only versus the system load levels while Figure 7-26 shows the scatter diagram of wind power allocated equally to all six zones versus system load levels. From visual comparison of the two diagrams, it can be seen that when all wind power plants are located in one zone, there will be many more times when less than 20% and higher than 90% of wind power generation capacity would occur. In contrast, with all wind plants in one zone, there would be much less chance of wind power generation of 20% to 60% of capacity occurring.

Figure 7-27 and Figure 7-28 show the occurrence frequency histograms against the system load level for the West zone and six zones respectively. Each set of the stacked bars shows the occurrence frequency (in hours) of a given load level within one year while each of these stacked bars shows the occurrence frequency of the wind power generation at the given load level as a percentage of installed capacity. For example, Figure 7-27 shows that the system will experience a total 2,784 hours of load ranging between 60% and 70% of its annual peak. Among these hours, there will be 187 hours of wind power at less than 1% of its rated capacity, 1,122 hours of wind power ranging between 1% and 20%, 435 hours of wind power ranging between 20% and 40%, 226 hours of wind power ranging between 40% and 60%, 213 hours of wind power ranging between 60% and 80%, and 601 hours of wind power ranging between 80% and 100%.

In contrast, Figure 7-28 shows that at the load level between 60% and 70% of the annual peak, there will be no chance for wind power at less than 1% of installed capacity, 537 hours of wind power ranging between 1% and 20%, 853 hours of wind power ranging between 20% and 40%, 782 hours of wind power ranging between 40% and 60%, 429 hours of wind power ranging between 60% and 80%, and 183 hours of wind power ranging between 80% and 100%.

Figure 7-29 and Figure 7-30 show the wind power generation histograms versus the system load level for the West zone and six zones respectively. They were created based on the histograms presented in Figure 7-27 and Figure 7-28. They can be understood in such a way that at a given load level, the system will have a certain percentage of time with a certain level of wind power generation. This can also be explained using the numbers given above. Figure 7-27 shows that the system will experience a total of 2,784 hours of load ranging between 60% and 70% of its annual peak. With 187 hours of wind power at less than 1% of its rated capacity, it could be interpreted that at this given load level, the system will have some 6.7% probability (187/2784*100=6.7%) of wind power generation less than 1% of capacity. The value of 6.7% is represented by the bottom segment of the 60% to 70% load level bar in Figure 7-29. The top segment of the 60% to 70% load level bar in this figure represents a probability of 21.6% (601/2784*100=21.6%) of wind power generation over 80% of capacity.

In comparison with Figure 7-29, Figure 7-30 for wind power installations in all six zones shows that at a load level between 60% to 70% of the annual peak, the probability for wind power at less than 1% is zero. At the same load level, the probability for wind power over 80% of capacity is 6.6% (183/2784*100=6.6%).

The graph presented in Figure 7-31 illustrates the hourly swing of wind power generation in January and February, which is the variation of the wind power generation between the current hour and the previous hour. On this graph, one set of observations is for all 600 MW of wind power plants located in one zone and the other is for 600 MW of wind power plants located in six zones, each with 100 MW. It can be seen from this figure that the one-zone set of observations has many more swings and much higher spikes than the six-zone curve.

Two parameters, standard deviation of hourly wind power ramps and average hourly wind power swing rate were also calculated to assess the impact of project size or concentration/diversity of projects. The calculated results are graphically presented in Figure 7-32. It can be seen from this figure that when wind power plants are equally allocated to six zones, the standard deviation of hourly load variations will be decreased to some 39 MW from some 76 MW (all wind power plants are in one zone). The average swing is also reduced to 29 MW (six zones) from some 47 MW (one zone). It can be generally stated that the more widely distributed the wind power projects, the less impact the wind plants will have on the system operational variability. It is important to note that these two parameters were calculated based on wind power generation only, without accounting for system hourly load.

The incremental impacts of wind project diversity/concentration on system operational variability were analyzed by keeping the total wind power generation at the 600 MW level while decreasing its diversity or increasing its concentration from six zones to one zone. The study results are presented in Table 7-15. In the calculations for this table, the net load, i.e. load minus wind power generation, was used. As shown in the table, the cases studied include:

(1) Without any wind power, i.e. load only

(2) Load and 600 MW of wind power, allocated equally to six zones

(3) Load and 600 MW of wind power, allocated equally to five zones

(4) Load and 600 MW of wind power , allocated equally to four zones

(5) Load and 600 MW of wind power , allocated equally to three zones

(6) Load and 600 MW of wind power , allocated equally to two zones

(7) Load and 600 MW of wind power in one zone.

It can be seen from Table 7-15 that when the 600 MW of wind power is located in six zones, the AGC and 10-minute load following requirements are 39.3 MW and 91.7 MW respectively. The requirements are increased to 59.7 MW and 145.8 MW when all 600 MW of wind power capacity is located in one zone, which imply increases of 20.4 MW in AGC service and 54.1 MW in 10-minute load following capability.

7.10 Quantification of Costs of Day Ahead Scheduling and Re-Dispatch

NSPI performs day ahead (forward) unit scheduling and two-hour ahead dispatch day scheduling for operation and business analysis. Day ahead scheduling means that the system operator has to determine the on-line schedule of its generation fleet one day before the dispatch day in order to give generators adequate time to prepare for the expected generation. The two-hour ahead dispatch day scheduling implies that the unit real-time dispatch schedule should be ready two hours earlier than its real-time operation. It is understood that the real-time operation results may deviate from the two-hour ahead dispatch scheduling due to various unforeseen reasons such as inaccurate forecasting of load demand and non-dispatchable power generation, generation or transmission facility outages, uncertain weather conditions and other system operation conditions, etc.

7.10.1 Day Ahead Unit Scheduling

For the day ahead unit scheduling, the NSPI Commercial Operations group prepares forecasts of domestic information for the next day by 8:00 AM each day, which includes hourly load demand, available generating units and their production costs, available grid transfer capability, potential export/import opportunities and expected energy prices, economic interruptible loads and their corresponding offer prices, etc. Based on the information collected, the Commercial Operations group will carry out economic and dispatch analysis for the next day and determine the planned unit generation/output schedule. By noon of the day, NSPI must submit its request on the scheduled tie-line transfer to the New Brunswick System Operator (NBSO) for assessment and approval. After two or more hours of information exchange between the NBSO and other electric system operators including NSPI, the NBSO will issue its instructions on the next day tie-line transfer schedule by 3:00 PM. This schedule will be valid for the period from 12:00 AM of the next day to 12:00 AM of the third day, a total of 24 hours.

As mentioned previously, the New Brunswick electric system is interconnected with the Nova Scotia (NS), Quebec (QC), Price Edward Island (PEI), Northern Maine (NM) and New England (NE) electric systems. The Quebec and New England systems are further interconnected with other Canadian and US electricity markets. As the physical transmission rights of the NB–NE tie-lines have been auctioned on a long term basis (5 to 15 years), Nova Scotia may export/import power via the NB-NE tie-lies only if the holders of the rights to these tie-lines temporarily release part or all of their rights. This means that NSPI must wait for tie-line transfer confirmation and cannot be sure on the outcome of requests. This situation does not apply to the NS-NB tie-line.

7.10.2 Two-Hour Ahead Dispatch Day Schedule

For two-hour ahead dispatch day scheduling, NSPI's, Commercial Operations group generally has a more accurate load forecast for next a few hours and would be more certain on the status and performance of domestic generating units, the status of intra-province transmission lines, the status of tie-lines and other important conditions impacting system operation such as temperature and wind. The two-hour ahead dispatch day analysis is to determine the unit generation schedule for the real-time operation hour, at least two hours before the hour, using the best information available. For example, by 11:00 AM, the unit generation schedule for the period from 1:00 PM to 2:00 PM should be finalized. The two-hour ahead dispatch day analysis provides a set of dispatch instructions to the system operator and provides an electricity price signal for dispatchable load. The deviations between the two-hour ahead dispatch day analysis and real-time operation could be accommodated by operating reserves, uncertainty allowance, interruptible load, quick start units and temporary tie-line imbalance.

7.10.3 Cost Analysis

It is understood that the incremental/decremental costs between day ahead unit scheduling,, re-dispatch (two-hour ahead dispatch day scheduling) and real-time operation are all caused by the uncertainties experienced by the system operation. These uncertainties include hourly load forecasting, reservoir/water flow conditions of hydroelectric stations, wind conditions of wind plants, status of other generating units and their fuel supply including coal, petcoke, natural gas, HFO and diesel, status of intra-province transmission lines and tie-lines, etc. When standing at a point in time which is one day or longer away from the real-time operation, the potential combinations of uncertainties are many and the combined magnitudes could be quite large. In order to demonstrate the potential impacts of various levels of wind power integration on the day ahead unit scheduling and two-hour ahead dispatch day scheduling, it was presumed that all these parameters, except for the wind power production, would be kept unchanged. For the Nova Scotia system, the incremental costs of wind power integration to the day ahead unit scheduling and re-dispatch can be assessed using the following steps:

(1) Estimate of the total daily cost from the day ahead unit scheduling by including the available wind power plants (the exact amount of wind power by location is dependent upon of the year and addition option under study). In this case, the output of wind plants is forecast one day (say 16 to 40 hours) earlier than the real-time system operation.

(2) Due to the inaccuracy of wind power forecasting used in the day ahead unit scheduling, the two-hour ahead dispatch day scheduling is based on more accurate wind power forecast results. For each forecast hour, the wind power could be equal to, lower than or higher than the forecast used before. The new forecasts may result in reduction or increase of generation of conventional units, a shortage of generation (quick-start capacity is used up) or surplus generation. The total daily cost would be the sum of 24 individual hourly costs.

(3) Calculate the daily differential costs of wind power integration using the values calculated from the steps above and the values from the daily real-time settlement.

It is obvious that calculation of the difference of costs between the day ahead unit scheduling or two-hour ahead dispatch day scheduling and real-time operation requires at least two market structures and associated information, one is the forward market settlement and the other is the real time market settlement. NSPI now has only the second market structure.

7.10.3.1 Impact of Wind Power Forecast Error on Unit Scheduling

Without any wind power plants on the system, the day ahead unit scheduling could be performed based on the forecast hourly load demands. When accounting for the wind power plants and knowing the expected wind power forecast error, the day ahead unit scheduling can be analyzed based on the forecast hourly load demands and the adjusted forecast hourly wind power output. Given a set of hourly wind power forecasts (most likely case) and a forecast error of 10%, it is expected that in most or all hours of the dispatch day, the actual wind power output will fluctuate between 90% and 110% (up to its maximum capacity) of the forecasted values. To account for the "worst" scenario in the day ahead unit scheduling analysis, it is suggested that the higher than expected wind power (110% of the forecasted value) should be applied to the low load periods such as hours from 1 to 6 and from 23 to 24 (or select 12 low load hours) while the lower than expected wind power (90% of the forecasted value) should be applied to the high load periods (the remaining hours of a day). By using the adjusted wind power generation, the system would have adequate dispatchable generating capacity to meet varying hourly load demands (the difference between daily maximum and minimum loads) as the net hourly loads (load minus wind power generation) are used in the day ahead unit scheduling. To understand easily the suggested approach, Table 7-16 presents the calculated net hourly load for two days in 2020, the annual peak load day (January 28) and one light load day (December 26 during the Christmas Holiday season), with a total of 581 MW of wind power installed on the system. To give a visual impression, the system hourly loads in the two days are graphically displayed in Figure 7-33 and Figure 7-34.

One can see from Table 7-16 that on January 28, 2020, the system will experience its daily hourly peak (also annual hourly peak) of 2,439 MW. The minimum hourly load in the day will be 1,933 MW. The difference (also variable load) between the two values is 506 MW. It could be understood that the generation fleet available in 2020 would have difficulty in meeting the load requirements if there is no wind power generation available during this day. When the most likely forecast of wind power for this day is directly used in the day ahead unit scheduling, one could find that the peak load (load minus wind) is reduced to 2,118 MW and the net minimum load is reduced to 1,656 MW with a daily variable load of 461 MW. If this set of hourly loads is used in the day ahead unit scheduling, the system may not have a dispatching problem as the variable load is relatively small. However, the generation system scheduled based on the day ahead unit scheduling may not be able to produce more power during the high load hours if the actual wind power generation (within the forecast error) is less than the forecasted amount, which could result in load interruptions. Similarly, the on-line generation fleet may not be able to reduce its output during the low load demand hours if the actual wind power generation is more than the forecasted amount, which could result in curtailments of wind power or spilling of water.

By using the adjusted wind forecast accounting for the expected forecast uncertainty, the daily hourly peak will be 2,145 MW and the minimum load will be 1,629 MW. The generation output schedule instructed as per the day ahead unit scheduling would be able to meet the forecasting error of wind power if the scheduling is based on the adjusted wind forecast.

There are some interesting findings when examining the data presented for December 26 in the same table. One can see that the daily hourly peak load is 1,672 MW and minimum load is 847 MW. The difference between the two values is 825 MW. Without any wind power generation, the generation fleet should be able to meet the load demand requirements. When using the adjusted wind power forecast (or most likely forecast), the generation fleet would face many challenges. The net system peak load is now 1,337 MW and the minimum load is 397 MW, with a difference of 939 MW. In order to meet the daily hourly peak load demand, the system would need to start some single-shift units for the next day operation in addition to dispatching the available quick start units. As all single-shift units (and most quick start thermal units) have a minimum loading requirement, the sum of the minimum loading requirements of the single-shift units required to operate the next day to meet the peak load demand, may be larger than the net minimum load. In order to alleviate or avoid these challenges, the system operator may be forced to perform one or more of the following actions (any one of these actions may result in additional costs to the Nova Scotia electric system:

(1) Interrupting industrial loads during high load hours

(2) Purchasing power at high prices from outside markets during high load hours

(3) Exporting surplus power at low prices to outside markets during low load hours

(4) Curtailing wind power generation during low load hours

(5) Spilling water during low load hours.

It is noted that in order to calculate the differential costs between the day ahead unit scheduling or the re-dispatch and real-time dispatch, different settlement structures must be devised with special rules to handle the commitments and imbalances. These rules may vary from one market to another but often involve balancing at the real-time price plus or minus a penalty. The generating units receiving dispatch instructions from each process should be assigned with a dollar value, in addition to variable costs such as fuel and O&M. For example, the starting process for a steam turbine driven generator may immediately be commenced for preparation for the next day's operation after receiving the dispatch instruction. The start-up time of a steam turbine driven generator may be longer than six to eight hours and the start-up costs could range from $10,000 to $20,000 or higher. The reason for this level of start-up costs is that either #6 oil or gas is used during the unit starting process. Another important factor to be considered is that most steam turbine driven units can not be cycled and each unit has a minimum loading requirement.

For other types of generators, there may also be costs involved after receiving dispatch instructions such as assigning operation staff, purchasing of gas, HFO and LFO at their market prices, or making decisions on water allocation.

It has been estimated that the start-up costs of each of the four Lingan units, two Trenton units and the Point Tupper unit are some $15,000. The start-up cost of the Point Aconi unit is some $13,000 per start. The start-up cost for each of the three Tufts Cove steam units is approximately $8,500.

7.10.3.2 Additional Operational Costs Due to Inaccurate Wind Power Forecasting

In addition to the costs mentioned in Subsection 7.10.3.1, the following costs resulting from electric system operations should also be considered and calculated:

(1) Tie-line imbalance charge. NBSO has established a charge rate for the scheduled tie-line reservations. The current rate is some $82/kW-Year, or $9.36/MWh. This rate is for the pre-approved transactions only. If the actual transfer is higher than scheduled, a 50% surcharge of the tie-line transfer rate will be applied, for a total change of $14.04/MWh. At present, the tie-line imbalance is calculated as the average of the actual transfers within every one hour. NBSO has advised that starting from January 1, 2008, the imbalance will be calculated on a 10-minute base, i.e. the average of the actual transfers within every 10 minutes, instead of on a one-hour base (currently used). It is understandable that the 10-minute calculation method would result in more charges to NSPI, or NSPI will have to pay more to the NBSO for tie-line imbalance

(2) Time-of-use electricity rate. The extra large industrial customers determine their electricity usage under the time-of-use category based on the forecast hourly tariff from the two-hour ahead dispatch day analysis performed by the Commercial Operations group. When the forecast hourly electricity rate is high, the customers may elect to curtail power consumption by reducing/suspending their production. Their production would then be resumed later when the forecast tariff is lower. As the decision of the customers is based on the forecast hourly energy price and the account settlement is based on the actual hourly average price (or 5-minute, 10-minute, 15-minute, 30-minute average price), it is expected that the two-hour ahead forecasted price is very close to the actual hourly average price. If the actual price deviates very significantly from its forecast value due to the inaccurate forecasting of wind power, it could result in extra large industrial customers consuming more power during high price hours and using less power during hours with lower prices. This will result in these customers paying more than expected and may also create hurdles/barriers for DSM programs

(3) Operational credits. In practice, some electricity markets may offer various credits to generators, importers, and/or extra large customers for the economic losses resulting from forecasting errors. However, it is understandable that these credits are finally paid by electricity consumers, government's funds, and/or from market operator's profits.

7.11 Wind Project Business Case With Output Curtailment

As the total installed capacity of wind power generation projects grows in the system, there would be more times when the system operator might wish to curtail wind power generation or to spill water to balance generation with load. The following is a list of possible reasons although it is not exhaustive:

(1) As per the day-ahead unit scheduling, the system may have to keep a minimum number of single-shift units on-line in order to meet the forecast daily minimum and maximum load demands as well as spinning reserve, AGC and load following requirements. At some points of time, the total system load including export could be less than the sum of the minimum loadings of the on-line single-shift units and the outputs of wind plants and run-of-river hydroelectric stations and other hydroelectric stations with reservoirs that are full

(2) Stringent constraints on tie-line operation. Based on the NPCC (Maritimes) operation rules, power transfer along the NS-NB tie line needs to be scheduled in advance. Short notice or unscheduled tie-line transfer may result in a substantial financial penalty. In some cases, curtailment of wind/hydro power may have lower cost impacts on the Nova Scotia electricity consumers

(3) Due to the inaccuracy of short-term forecasting of wind and non-dispatchable hydro power, the actual generation from wind plants and non-dispatchable hydroelectric stations could be more than the forecast amount and the outputs of on-line thermal units could not be reduced to accommodate the higher than expected wind/hydro power generation

(4) Due to the uncontrollable conditions, actual system load may be less than that forecast. In this case, some wind power generation may have to be curtailed in order to keep the supply and demand in balance and meet the ancillary services requirements

(5) Distributed generators and load customers are connected to one single feeder from a substation. When the feeder is long (such as 50 KM or longer) and local load demand is low, the operation of some of these generators could cause voltage violation in some parts of the feeder. In these cases, curtailment of generation from the distributed generators could be required

(6) The system loses some load due to various reasons but the generation from conventional generating units could not be reduced to meet the new supply/demand balance

(7) Due to loss of transmission/distribution lines, one part or several parts of the network become isolated. The generation of wind plants in the isolated networks may have to be either partially or fully curtailed

(8) Due to loss of transmission/distribution lines, the output of one or several wind plants /hydroelectric stations must be either partially or fully curtailed due to the transfer limits of other lines

(9) Curtailment of wind/hydro power could result in lower total cost as the heat rate of a thermal unit decreases as its output increases if the energy clearing price (uniform price) within an interval of time is determined by the offer prices of a marginal unit/plant and the offer prices are the product of pre-determined heat rates and fuel price.

The potential impact of wind power curtailment on the financial performance of two 50 MW wind power plants was evaluated by assuming that one plant would be located in the Sydney zone (with the highest expected annual capacity factor among the six zones in the province) and the other would be located in the Truro zone (with the lowest expected annual capacity factor). Except for the estimated capacity factors, all other parameters are assumed identical for the two wind power plants. As the purpose of this analysis is to demonstrate the potential financial impact of wind power curtailment, the corresponding financial analysis was simplified. For the analysis described in this subsection, the following assumptions are applied:

(1) The expected annual capacity factors of the wind plants in the Sydney and Truro zones are based on Hatch's estimates presented in Subsection 4.6

(2) The expected annual energy production of a wind power plant is equal to its installed capacity multiplied by the estimated annual capacity factor, and multiplied by 8760

(3) Similar to the NSPI 2007 IRP, an energy rate of $80 per MWh (energy price for RES 2013) in 2007 dollars is used for the two wind power plants. By 2013, this energy rate will be adjusted to $90.093 per MWh as per the assumed escalation rate and it will be fixed for the entire contract period of 25 years without any adjustment

(4) As per the current Federal Government policy, the ecoEnergy credit of $10 per MWh is applied in the first 10 years, which will not be escalated

(5) The overnight unit investment cost of the plants was presumed as $2,200 per kilo-watt in 2007 dollars. The total investment in the power plants will be some $123.9 million by the beginning of 2013, when the plants start commercial operation as part of RES 2013. The overnight investment cost covers the equipment, balance of plant, interconnection to the grid, engineering, land acquisition or right of way, financing, project development and other items. However, it does not include the capital contribution to grid additions, upgrades or reinforcements when necessary

(6) The annual O&M costs are assumed as 2% of the initial capital investment and are escalated as per the specified escalation rate

(7) Financial parameters such as debt equity ratio, debt interest rate, discount rate and escalation rate are the same as those used in the NSPI 2007 IRP

(8) The analysis is carried out based on pre-tax values

(9) In the annual cash flows, it is assumed that expenses and revenue will occur at the end of a year.

Table 7-17 and Table 7-18 present the simplified financial analysis results for the 50 MW wind power plants located in the Sydney and Truro zones respectively, without accounting for any curtailment. In addition to the assumptions used and calculated financial indices, the two tables present annual expenses/revenue flows over a 25 year project life. As seen from these two tables, the calculated financial index is the internal rate of return (IRR). The annual cash flows include the debt payment, O&M cost, energy revenue, eco-Energy credit and pre-tax earnings.

As seen from Table 7-17, the investor would obtain a pre-tax IRR of 19.395% if the power plant is located in the Sydney zone. One can find from Table 7-18 that the pre-tax IRR would be reduced significantly to 5.28% when the wind power plant is located in the Truro zone.

The impact of wind power curtailment on the financial performance of wind power plants was studied by varying both the curtailment rate and the capital investment, using the analysis approach presented in Table 7-17 and Table 7-18. The study results for the two plants in the Sydney and Truro zones are presented in Table 7-19 and Table 7-20 respectively. In these two tables, in addition to the cases without wind power curtailment, two levels of curtailment, i.e. 5% and 10% of the annual energy potential are also presented. In order to assess the sensitivity of the results, three levels of the initial capital investment ($2,200/kW, $2,500/kW and $2,800/kW) are also used.

Table 7-19 indicates that with a 5% annual level of curtailment, the pre-tax IRR would be reduced by more than 2.3% percentage points with a 10% annual level of curtailment the rate of return on equity would be reduced by close to 5 percentage points. It can also be seen from this table what the financial performance of the project would be when the required initial capital investment increases to $2800/kW.

When the project is located in the Truro zone, the IRRs as presented in Table 7-20 are much less attractive than those for the project located in the Sydney zone.

It can be concluded from the financial analysis results presented in Table 7-19 and Table 7-20 that curtailment of wind power at the levels postulated would have significant impacts on the financial performance of wind power plants if the owners were not compensated for energy that the system cannot use.

7.12 Key Barriers

As per the descriptions and discussions presented in this report, one can find that the key barriers to integration of wind power capacity include the following:

(1) Locations of wind power plants

(2) Diversity of wind power

(3) Wind power forecasting error

(4) Forward market

(5) Curtailment of wind power and spilling of water

(6) Impacts on operation of NSPI thermal plants and delivery systems.

It is noted that the conclusions for 311 and 581 MW of wind power capacity are predicated on the assumed distributions of the wind power capacity amongst the zones.

7.12.1 Locations of Wind Power Plants

The study results presented in this report are based on the assumed zonal allocations of wind power plants. It can be understood that the locations of future wind power plants could have significant impact on total system cost and system transfer capability. For example, integration of a significant amount of new wind power capacity in the Canso Strait and Sydney zones could require construction of a new 345 kV transmission line running from the Canso Strait zone to the Metro zone as the current East-West transmission corridor has limited capability to transmit the output of new wind power generation in the two zones.

The transmission corridors between any two of the seven zones have transfer limits. It will trigger a requirement for transmission reinforcement if beyond a certain amount of wind power capacity is located in one zone and the wind power is required to be evacuated and transferred to the major load centres.

As construction of major new transmission lines is very expensive and time consuming, it could be cost effective and technically viable to develop new wind power capacity in the zones from which the existing transmission system (or with minor reinforcement) can transfer the power generated to the major load centres.

7.12.2 Diversity of Wind Power

It is generally recognized that diversification of wind power across one jurisdiction will reduce not only the overall generation variability but also the risk of sudden massive reductions in wind generation. For an existing power system, diversity could also avoid or delay capital investment in transmission line additions or reinforcements.

Generation variability has a direct impact on system AGC and load following requirements. Concentration of wind power plants will generally increase these system requirements and the system therefore needs more generating capacity with the capability to provide these services. It could also be true that the deterministic generation planning criterion of 20% firm capacity reserve should be reviewed and adjusted.

7.12.3 Wind Power Forecasting Error

Due to the variable nature of wind power, it is understandable that there is always the potential for an error in hourly or short-interval wind power forecasting. The forecasting error or the difference between the real-time output and forecast generation could result in additional system costs or sometimes unexpected benefits.
As discussed in Subsection 7.9, the forecast of wind power production is used in day ahead unit scheduling and two-hour ahead dispatch day analysis. The accuracy of the wind power forecasting plays an important role in the decision making process for unit commitment and dispatch. It is recommended that Nova Scotia follow the approach of other jurisdictions such as Alberta and establish a wind power forecasting pilot project when the system has a total of some 300 MW of wind power generation installed.

7.12.4 Forward Market

Based on the current market structure, it is very difficult or impossible to estimate the costs of wind power forecasting error. The costs of wind power forecasting error should be the cost difference between the value calculated from day ahead unit scheduling and two hour ahead dispatch day analysis and the value calculated from real-time operation. To calculate the total cost form the forward market, the forward market settlement rules must be first established.

As a minimum, the forward market must have rules or policies for the following:

(1) Compensation mechanism for dispatchable units committed as per the order from the day ahead unit scheduling analysis and actually generated more or less than scheduled

(2) Compensation mechanism for dispatchable units committed as per the order from the two-hour ahead dispatch day analysis and actually generated more or less than scheduled

(3) Penalty mechanism for non-dispatchable units forecasted as per the day ahead unit scheduling analysis and actually generated more or less than forecasted

(4) Penalty mechanism for non-dispatchable units forecasted as per the order from the two-hour ahead dispatch day analysis and actually generated more or less than forecasted.

7.12.5 Curtailment of Wind Power and Spilling of Water

Subsection 7.10 listed various factors that could result in curtailment of wind power and spilling of water. It is understandable that most of these are due to low system demand. Energy storage technologies can absorb the system "dump" energy (or increase the system demand) during low system load demand periods and provide additional generation during high system load demand periods. Such technologies can provide increased flexibility for system operation and therefore reduce the chances of wind power curtailment and spilling of water.

The pumped storage/wind power project proposed for Cape Breton is one example but there are many other possible storage technologies that are actively being researched and developed.

7.12.6 Impacts on Operation of NSPI Thermal Units

As described in Subsection 2.3 and presented in Table 2-1, as of June 30, 2007, NSPI had a total of some 2,314 MW net firm generating capacity at the time of system peak, of which 1,252 MW was from coal/petcoke units and 321 MW was from HFO/gas units. These steam turbine driven units account for some 68% of total system net firm generating capacity. Operation of these units is much less flexible than operation of GTs, CTs and CCs as they are subject to many important operational constraints. Some of these are:

(1) Minimum loading requirement

(2) Minimum loading requirement for providing AGC service, if applicable

(3) Minimum down time requirement

(4) Minimum up time requirement

(5) The length of time required for start-up and shutdown

(6) High start-up costs

(7) Relatively low ramp rates.

When high levels of wind power capacity are added to the system, the system would require that these steam turbine driven generating units operate quite differently than the operating modes they were designed for. For example, they might be shutdown more frequently and their outputs would fluctuate more frequently. The increased variability in the production levels of the major generating units would also place increased stress on many components of the delivery system.

Table 7-1: Operational Variability of Wind Power – Base Plan

		2008	2010			2013		2020			
Time Scale	Technical Issue	61 MW Wind	61 MW Wind	311 MW Wind (1)	311 MW Wind (2)	61 MW Wind	581 MW Wind	61 MW Wind	311 MW Wind (1)	311 MW Wind (2)	581 MW Wind
Yearly	Wind Capacity Factor										
	Annual (%)	36.05	36.05	36.80	33.40	36.05	35.52	36.05	36.80	33.40	35.52
	Winter (%)	42.58	42.58	41.23	38.18	42.58	40.40	42.58	41.23	38.18	40.40
	Summer (%)	29.62	29.62	32.45	28.70	29.62	30.71	29.62	32.45	28.70	30.71
	Annual Maximum Hourly Load (MW)	2264	2330	2263	2321	2368	2253	2403	2331	2394	2288
	Annual Minimum Hourly Load (MW)	807	805	744	681	776	504	699	657	594	440
	Annual Hourly Load Variation (MW)	1457	1525	1519	1640	1592	1749	1704	1674	1800	1848
Hours	Maximum Daily Variation (MW)	853.4	896.5	984.4	1046.0	938.7	1171.7	1009.8	1097.8	1157.0	1241.4
	Daily Incremental Variation (MW)	--	--	87.9	149.5	--	233.0	--	88.0	147.2	231.6
	Scheduling (3-hour delta), σ (MW) (3)	152.8	161.0	159.8	160.6	169.1	170.0	182.8	181.2	181.7	182.9
	Largest 3-Hour Rise (MW)	434.5	452.5	458.1	499.4	470.1	534.1	499.8	508.0	543.9	565.8
	Largest 3-Hour Drop (MW)	-359.4	-376.9	-404.0	-385.2	-394.2	-482.4	-423.2	-446.3	-421.7	-505.3
	Scheduling (1-hour delta), σ (MW)	66.3	69.6	71.4	73.2	73.0	80.4	78.6	80.0	81.6	85.3
	Largest 1-Hour Rise (MW)	265.8	276.3	265.7	279.3	286.8	309.4	304.3	295.6	310.8	329.2
	Largest 1-Hour Drop (MW)	-212.0	-223.2	-217.9	-237.1	-234.2	-250.1	-252.8	-245.0	-264.2	-263.2
	Maximum Hourly Load Variation (MW)	300.3	303.8	306.8	307.8	304.0	366.0	301.1	304.1	311.7	364.1
Minutes	Load Following (10-minute delta), σ (MW)	15.4	16.0	21.0	22.6	16.7	29.7	18.3	22.8	24.2	30.6
	Largest 10-Minute Rise (MW)	92.0	97.3	142.2	175.4	104.6	222.8	129.4	171.9	183.3	221.6
	Largest 10-Minute Drop (MW)	-155.7	-157.4	-154.0	-193.9	-157.5	-228.2	-156.1	-152.7	-193.8	-228.1
	Load Following Requirement (3*σ, MW) (4)	46.2	48.0	63.1	67.8	50.2	89.0	54.8	68.4	72.7	91.7
	Incremental Requirement (MW/10-minute)	--	--	15.1	19.7	--	38.8	--	13.6	17.9	36.8
	Incremental Requirement (%)	--	--	31.4	41.1	--	77.4	--	24.7	32.6	67.2
	Load Following (5-minute delta), σ (MW)	9.8	10.1	14.2	15.3	10.5	20.6	11.5	15.2	16.2	21.1
	Largest 5-Minute Rise (MW)	74.6	76.4	146.1	183.3	80.6	230.4	95.0	173.7	181.5	229.3
	Largest 5-Minute Drop (MW)	-229.4	-231.6	-232.3	-231.6	-231.7	-233.2	-229.9	-230.6	-229.9	-231.3
	Regulation (1-minute delta), σ (MW)	4.9	5.0	8.3	8.6	5.2	12.5	5.4	8.6	8.8	12.6
	Largest 1-Minute Rise (MW)	62.5	64.5	148.6	199.3	65.9	245.8	89.6	169.7	197.5	244.4
	Largest 1-Minute Drop (MW)	-216.4	-219.8	-221.9	-224.8	-220.0	-238.5	-217.2	-219.2	-222.2	-238.5
	Regulation Requirement (3*σ, MW)	14.8	15.1	25.0	25.7	15.5	37.5	16.3	25.7	26.4	37.9
	Incremental Requirement (MW/1-minute)		--	9.9	10.6	--	22.1	--	9.4	10.1	21.6
	Incremental Requirement (%)		--	65.4	70.0	--	142.9	--	57.7	61.9	132.2

Table 7-2: Impact of Wind Timing on Operational Variability in 2020

Time Scale	Technical Issue	61 MW Wind	Moving Window for 581 MW Wind												
			0 Hour	2 Hours	4 Hours	6 Hours	8 Hours	10 Hours	12 Hours	14 Hours	16 Hours	18 Hours	20 Hours	22 Hours	24 Hours
Yearly	Annual Maximum Hourly Load (MW)	2403	2288	2307	2296	2297	2334	2374	2376	2374	2340	2339	2389	2364	2305
	Annual Minimum Hourly Load (MW)	699	440	428	439	437	431	458	400	361	334	313	344	361	480
	Annual Hourly Load Variation (MW)	1704	1848	1879	1857	1860	1903	1916	1976	2013	2006	2026	2045	2003	1825
Hours	Maximum Daily Variation (MW)	1009.8	1241.4	1231.2	1185.0	1212.6	1185.0	1181.5	1139.1	1151.8	1099.0	1173.1	1159.9	1153.3	1207.8
	Daily Incremental Variation (MW)	--	231.6	221.4	175.2	202.8	175.2	171.7	129.3	142.0	89.2	163.3	150.1	143.5	198.0
	Scheduling (3-hour delta), σ (MW)	182.8	182.9	187.5	192.0	193.4	191.9	192.0	195.3	199.4	202.5	200.4	192.2	185.0	182.9
	Largest 3-Hour Rise (MW)	499.8	565.8	584.2	587.3	567.7	628.8	592.4	646.4	656.0	654.3	574.5	552.9	539.8	551.3
	Largest 3-Hour Drop (MW)	-423.2	-505.3	-507.7	-528.0	-537.7	-475.9	-506.0	-588.6	-564.4	-551.3	-533.8	-477.3	-468.5	-484.1
	Scheduling (1-hour delta), σ (MW)	78.6	85.3	87.4	89.0	88.9	88.7	87.6	89.2	90.5	91.1	91.3	88.5	86.1	85.6
	Largest 1-Hour Rise (MW)	304.3	329.2	465.7	379.0	323.6	395.1	355.4	363.0	357.2	349.5	366.1	341.1	357.2	342.3
	Largest 1-Hour Drop (MW)	-252.8	-263.2	-325.7	-317.3	-329.8	-318.4	-330.7	-302.2	-315.5	-349.6	-339.4	-324.8	-349.7	-283.5
	Maximum Hourly Load Variation (MW)	301.1	364.1	404.3	387.5	466.5	409.3	369.5	377.8	393.7	392.3	370.2	379.6	361.4	362.1
Minutes	Load Following (10-minute delta), σ (MW)	18.3	30.6	30.7	30.9	30.8	30.9	30.8	30.9	31.1	31.0	31.1	30.8	30.6	30.6
	Largest 10-Minute Rise (MW)	129.4	221.6	201.5	229.1	270.8	219.7	229.2	230.4	220.8	243.1	260.3	267.1	282.6	288.4
	Largest 10-Minute Drop (MW)	-156.1	-228.1	-241.6	-230.3	-217.6	-238.7	-230.9	-244.9	-237.3	-270.7	-235.2	-224.9	-223.9	-216.8
	Load Following Requirement (3*σ, MW)	54.8	91.7	92.1	92.7	92.5	92.7	92.4	92.6	93.2	92.9	93.2	92.4	91.9	91.8
	Incremental Requirement (MW/10-minute)	--	36.8	37.3	37.9	37.6	37.9	37.6	37.8	38.3	38.1	38.4	37.6	37.1	36.9
	Incremental Requirement(%)	--	67.2	68.0	69.1	68.6	69.0	68.5	68.9	69.9	69.4	70.0	68.6	67.7	67.3
	Load Following (5-minute delta), σ (MW)	11.5	21.1	21.2	21.3	21.3	21.3	21.3	21.3	21.4	21.3	21.4	21.2	21.2	21.1
	Largest 5-Minute Rise (MW)	95.0	229.3	227.7	231.6	265.5	229.4	232.6	236.1	237.0	242.0	243.9	262.2	275.1	286.6
	Largest 5-Minute Drop (MW)	-229.9	-231.3	-238.0	-229.8	-230.7	-233.4	-232.3	-238.2	-234.4	-239.1	-231.6	-231.9	-228.2	-227.0
	Regulation (1-minute delta), σ (MW)	5.4	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.7	12.7	12.7	12.7	12.6	12.6
	Regulation Requirement (3*σ, MW)	16.3	37.9	37.9	37.9	37.9	37.9	37.9	37.9	38.0	38.0	38.0	38.0	37.9	37.9
	Incremental Requirement (MW/1-minute)	--	21.6	21.6	21.6	21.6	21.6	21.6	21.6	21.7	21.7	21.7	21.6	21.6	21.6
	Incremental Requirement (%)	--	132.2	132.1	132.4	132.4	132.5	132.5	132.5	132.7	132.8	133.0	132.6	132.2	132.1

Table 7-3: Operational Variability of Wind Power – Alternative Plans

Time Scale	Technical Issue	61 MW Wind	311 MW Wind (1)	311 MW Wind (2)	581 MW Wind (3)	781 MW Wind (4)	781 MW Wind (5)	981 MW Wind (6)	981 MW Wind (7)
		2020							
Yearly	Wind Capacity Factor								
	Annual (%)	36.05	36.80	33.40	35.52	37.58	34.94	36.57	36.71
	Winter (%)	42.58	41.23	38.18	40.40	41.84	40.59	41.31	41.69
	Summer (%)	29.62	32.45	28.70	30.71	33.40	29.39	31.91	31.80
	Annual Maximum Hourly Load (MW)	2403	2331	2394	2288	2255	2283	2251	2245
	Annual Minimum Hourly Load (MW)	699	657	594	440	318	266	141	141
	Annual Hourly Load Variation (MW)	1704	1674	1800	1848	1937	2017	2110	2104
Hours	Maximum Daily Variation (MW)	1009.8	1097.8	1157.0	1241.4	1311.9	1376.6	1415.2	1385.4
	Daily Incremental Variation (MW)	--	88.0	147.2	231.6	302.1	366.8	405.4	375.6
	Scheduling (3-hour delta), σ (MW) (8)	182.8	181.2	181.7	182.9	189.2	186.2	193.6	192.3
	Largest 3-Hour Rise (MW)	499.8	508.0	543.9	565.8	675.5	625.9	671.8	668.0
	Largest 3-Hour Drop (MW)	-423.2	-446.3	-421.7	-505.3	-601.4	-539.2	-645.1	-635.3
	Scheduling (1-hour delta), σ (MW)	78.6	80.0	81.6	85.3	92.8	89.8	98.7	96.9
	Largest 1-Hour Rise (MW)	304.3	295.6	310.8	329.2	403.2	340.9	403.9	400.4
	Largest 1-Hour Drop (MW)	-252.8	-245.0	-264.2	-263.2	-369.8	-290.8	-366.0	-389.4
	Maximum Hourly Load Variation (MW)	301.1	304.1	311.7	364.1	536.7	402.6	560.3	564.4
Minutes	Load Following (10-minute delta), σ (MW)	18.3	22.8	24.2	30.6	41.1	35.3	46.1	44.8
	Largest 10-Minute Rise (MW)	129.4	171.9	183.3	221.6	340.2	265.7	380.1	360.6
	Largest 10-Minute Drop (MW)	-156.1	-152.7	-193.8	-228.1	-319.9	-263.6	-327.4	-323.7
	Load Following Requirement (3*σ, MW) (9)	54.8	68.4	72.7	91.7	123.4	105.9	138.4	134.3
	Incremental Requirement (MW/10-minute)	--	13.6	17.9	36.8	68.6	51.0	83.6	79.5
	Incremental Requirement (%)	--	24.7	32.6	67.2	125.1	93.1	152.5	144.9
	Load Following (5-minute delta), σ (MW)	11.5	15.2	16.2	21.1	29.2	24.7	32.8	31.8
	Largest 5-Minute Rise (MW)	95.0	173.7	181.5	229.3	401.1	273.3	441.3	421.5
	Largest 5-Minute Drop (MW)	-229.9	-230.6	-229.9	-231.3	-321.3	-251.9	-330.1	-325.3
	Regulation (1-minute delta), σ (MW)	5.4	8.6	8.8	12.6	19.0	15.0	21.1	20.7
	Largest 1-Minute Rise (MW)	89.6	169.7	197.5	244.4	403.1	288.5	442.6	423.3
	Largest 1-Minute Drop (MW)	-217.2	-219.2	-222.2	-238.5	-409.2	-282.6	-452.4	-430.8
	Regulation Requirement (3*σ, MW)	16.3	25.7	26.4	37.9	57.0	45.0	63.2	62.0
	Incremental Requirement (MW/1-minute)	--	9.4	10.1	21.6	40.7	28.7	46.9	45.7
	Incremental Requirement (%)	--	57.7	61.9	132.2	249.5	175.9	287.4	279.9

Note:

(1) -- A total of 250 MW new wind generation capacity is allocated to Valley (40 MW), Truro (50 MW), Pictou (60 MW) and Canso Strait (100 MW).
(2) -- A total of 250 MW new wind generation capacity is allocated to Valley (40 MW), Truro (80 MW), Pictou (120 MW) and Canso Strait (10 MW).
(3) -- A total of 520 MW new wind generation capacity is allocated to West (30 MW), Valley (110 MW), Truro (110 MW), Pictou (140 MW), Canso Strait (110 MW) and Sydney (20 MW).
(4) -- A total of 720 MW new wind generation capacity is allocated to West (30 MW), Valley (110 MW), Truro (110 MW), Pictou (140 MW), Canso Strait (310 MW) and Sydney (20 MW).
(5) -- A total of 720 MW new wind generation capacity is allocated to West (130 MW), Valley (160 MW), Truro (160 MW), Pictou (140 MW), Canso Strait (110 MW) and Sydney (20 MW).
(6) -- A total of 920 MW new wind generation capacity is allocated to West (130 MW), Valley (110 MW), Truro (210 MW), Pictou (140 MW), Canso Strait (310 MW) and Sydney (20 MW).
(7) -- A total of 920 MW new wind generation capacity is allocated to West (130 MW), Valley (160 MW), Truro (160 MW), Pictou (140 MW), Canso Strait (310 MW) and Sydney (20 MW).
(8) -- σ is the standard deviation of the load deltas (variations) for a time period of x minutes or hours.
(9) -- 3*σ is three times of the standard deviation of the deltas for the period of x minutes or hours, or 99.72% of all values in a normal distributed population. This is used to define incremental requirements to maintain system performance.

Table 7-4: Emissions Summary – 2010

Total Wind Integration (MW)	61	311 Opt 1	311 Opt 2	Cap
Estimated Emissions				
CO2 (KT)	10633	10026	10083	10000
SO2 (KT)	74.493	70.668	70.947	72.500
NOx (KT)	22.373	20.411	20.539	21.440
Hg (Kg)	34.722	33.585	33.662	65.000
Estimated Emission Reductions				
CO2 (KT)	--	607	550	
SO2 (KT)	--	3.825	3.546	
NOx (KT)	--	1.962	1.835	
Hg (Kg)	--	1.137	1.061	

Table 7-5: Emissions Summary – 2013

Total Wind Integration (MW)	61	581	Cap
Estimated Emissions			
CO2 (KT)	10626	9348	10000
SO2 (KT)	77.208	67.476	72.500
NOx (KT)	22.407	18.540	21.440
Hg (Kg)	31.402	28.606	65.000
Estimated Emission Reductions			
CO2 (KT)	--	1278	
SO2 (KT)	--	9.732	
NOx (KT)	--	3.867	
Hg (Kg)	--	2.796	

Table 7-6: Emissions Summary – 2020

Total Wind Integration (MW)	61	311 Opt 1	311 Opt 2	581	781 Opt 1	781 Opt 2	981 Opt 1	981 Opt 2	Cap
Estimated Emissions									
CO_2 (KT)	10430	9812	9872	9129	8354	8546	7777	7783	10000
SO_2 (KT)	42.131	38.767	38.890	34.974	31.701	32.366	29.191	29.290	36.250
NO_x (KT)	18.093	16.401	16.536	14.904	13.615	13.907	13.329	13.357	14.700
Hg (Kg)	25.999	24.973	25.053	23.354	21.011	21.717	19.014	19.093	34.000
Estimated Emission Reductions									
CO_2 (KT)	--	618	558	1301	2076	1884	2654	2648	
SO_2 (KT)	--	3.363	3.240	7.156	10.430	9.765	12.939	12.841	
NO_x (KT)	--	1.692	1.558	3.189	4.479	4.187	4.765	4.737	
Hg (Kg)	--	1.025	0.946	2.645	4.988	4.282	6.985	6.906	

Table 7-7: Estimated Avoided Costs of GHG Emissions

Year	Total Wind Power Integration (MW)	CO_2 Reductions (kT)	CO_2 Costs * ($/Tonne)	Avoided Cost (M$)
2008	61	--	--	--
2010	61 311 (Opt 1) 311 (Opt 2)	-- 607 550	-- 15.06 15.06	-- 9.147 8.282
2013	61 581	-- 1278	-- 22.40	-- 28.635
2020	61 311 (Opt 1) 311 (Opt 2) 581 781 (Opt 1) 781 (Opt 2) 981 (Opt 1) 981 (Opt 2)	-- 618 558 1301 2076 1884 2654 2648	-- 38.76 38.76 38.76 38.76 38.76 38.76 38.76	-- 23.963 21.638 50.431 80.484 73.035 102.862 102.629

Source: Table 5.5, Basic Modelling Assumptions for Integrated Resource Plans, April 2007, NSPI.

Table 7-8: Generation and Cost Summary – 2010

Annual Peak Demand (MW)		**2362**	
Total Wind Integration (MW)	**61**	**311 Opt 1**	**311 Opt 2**
Energy Generation (GWh)	**13381**	**13381**	**13381**
Thermal	12010.7	11203.6	11290.9
Wind	191.5	995.0	907.0
Other Renewables	1178.7	1182.4	1183.1
Renewable (Post 2001)	191.5	995.0	907.0
Total Renewable	1370.3	2177.4	2090.1
Generation by Type (%)	**100.0**	**100.0**	**100.0**
Thermal	89.76	83.73	84.38
Wind	1.43	7.44	6.78
Other Renewables	8.81	8.84	8.84
Renewable (Post 2001)	1.43	7.44	6.78
Total Renewable	10.24	16.27	15.62
Total Costs ($M)	**728.9**	**727.8**	**728.1**
Benefits of New Wind Energy ($/MWh)	--	1.32	1.08
Total Costs Excluding CO2 Offset Costs ($M)	**568.8**	**576.8**	**576.3**
Benefits of New Wind Energy ($/MWh)	--	-10.06	-10.50

Table 7-9: Generation and Cost Summary – 2013

Annual Peak Demand (MW)	**2398**	
Total Wind Integration (MW)	**61**	**581**
Energy Generation (GWh)	**13363**	**13363**
Thermal	11990.3	10414.5
Wind	191.5	1769.9
Other Renewables	1181.2	1178.6
Renewable (Post 2001)	191.5	1769.9
Total Renewable	1372.7	2948.5
Generation by Type (%)	**100.0**	**100.0**
Thermal	89.73	77.94
Wind	1.43	13.24
Other Renewables	8.84	8.82
Renewable (Post 2001)	1.43	13.24
Total Renewable	10.27	22.06
Total Costs ($M)	**900.7**	**901.1**
Benefits of New Wind Energy ($/MWh)	--	-0.26
Total Costs Excluding CO2 Offset Costs ($M)	**662.6**	**691.7**
Benefits of New Wind Energy ($/MWh)	--	-18.40

Table 7-10: Generation and Cost Summary – 2020

Annual Peak Demand (MW)				**2431**				
Total Wind Integration (MW)	**61**	**311 Opt 1**	**311 Opt 2**	**581**	**781 Opt 1**	**781 Opt 2**	**981 Opt 1**	**981 Opt 2**
Energy Generation (GWh)	**13094**	**13094**	**13094**	**13094**	**13094**	**13094**	**13094**	**13094**
Thermal	11716.1	10917.6	11009.5	10151.3	9373.0	9537.7	8816.1	8794.4
Wind	191.5	995.0	907.0	1769.9	2568.5	2385.5	3131.7	3144.0
Other Renewables	1186.4	1181.4	1177.5	1172.8	1152.5	1170.8	1146.2	1155.6
Renewable (Post 2001)	191.5	995.0	907.0	1769.9	2568.5	2385.5	3131.7	3144.0
Total Renewable	1377.9	2176.4	2084.5	2942.7	3721.0	3556.3	4277.9	4299.6
Generation by Type (%)	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Thermal	89.48	83.38	84.08	77.53	71.58	72.84	67.33	67.16
Wind	1.46	7.60	6.93	13.52	19.62	18.22	23.92	24.01
Other Renewables	9.06	9.02	8.99	8.96	8.80	8.94	8.75	8.83
Renewable (Post 2001)	1.46	7.60	6.93	13.52	19.62	18.22	23.92	24.01
Total Renewable	10.52	16.62	15.92	22.47	28.42	27.16	32.67	32.84
Total Costs ($M)	**1246.9**	**1201.3**	**1207.1**	**1196.8**	**1292.5**	**1224.4**	**1373.6**	**1365.8**
Benefits of New Wind Energy ($/MWh)	--	56.73	55.57	31.75	-19.20	10.27	-43.10	-40.26
Total Costs Excluding CO2 Offset Costs ($M)	**842.6**	**821.0**	**824.5**	**843.0**	**968.7**	**893.1**	**1072.2**	**1064.1**
Benefits of New Wind Energy ($/MWh)	--	26.90	25.33	-0.21	-53.06	-23.02	-78.08	-75.02

Table 7-11: Total System Costs at Different Wind Energy Prices – 2010

Total Wind Integration (MW)	61	311 Opt 1	311 Opt 2
Total Costs ($M)			
Wind Energy Price at $70/MWh	725.8	712.4	713.7
Wind Energy Price at $80/MWh	727.9	723.0	723.3
Wind Energy Price at $100/MWh	731.9	744.3	742.6
Wind Energy Price at $120/MWh	736.0	765.5	761.9
Total Costs Excluding CO2 Offset Costs ($M)			
Wind Energy Price at $70/MWh	565.7	561.4	561.9
Wind Energy Price at $80/MWh	567.7	572.1	571.5
Wind Energy Price at $100/MWh	571.8	593.3	590.7
Wind Energy Price at $120/MWh	575.9	614.5	610.0

Table 7-12: Total System Costs at Different Wind Energy Prices – 2013

Total Wind Integration (MW)	61	581
Total Costs ($M)		
Wind Energy Price at $70/MWh	897.6	876.6
Wind Energy Price at $80/MWh	899.7	896.3
Wind Energy Price at $100/MWh	903.7	935.6
Wind Energy Price at $120/MWh	907.8	974.9
Total Costs Excluding CO2 Offset Costs ($M)		
Wind Energy Price at $70/MWh	659.6	667.3
Wind Energy Price at $80/MWh	661.6	686.9
Wind Energy Price at $100/MWh	665.7	726.2
Wind Energy Price at $120/MWh	669.8	765.5

Table 7-13: Total System Costs at Different Wind Energy Prices – 2020

Total Wind Integration (MW)	61	311 Opt 1	311 Opt 2	581	781 Opt 1	781 Opt 2	981 Opt 1	981 Opt 2
Total Costs ($M)								
Wind Energy Price at $70/MWh	1243.9	1185.9	1192.7	1172.4	1257.8	1192.0	1331.6	1323.6
Wind Energy Price at $80/MWh	1245.9	1196.5	1202.4	1192.0	1287.8	1219.6	1368.8	1361.0
Wind Energy Price at $100/MWh	1250.0	1217.8	1221.6	1231.3	1347.7	1274.8	1443.4	1435.8
Wind Energy Price at $120/MWh	1254.0	1239.0	1240.9	1270.6	1407.7	1330.0	1517.9	1510.7
Total Costs Excluding CO2 Offset Costs ($M)								
Wind Energy Price at $70/MWh	839.6	805.6	810.1	818.5	934.0	860.7	1030.2	1021.9
Wind Energy Price at $80/MWh	841.6	816.2	819.7	838.2	964.0	888.3	1067.4	1059.4
Wind Energy Price at $100/MWh	845.7	837.5	839.0	877.5	1023.9	943.6	1141.9	1134.2
Wind Energy Price at $120/MWh	849.7	858.7	858.2	916.7	1083.9	998.8	1216.5	1209.0

Table 7-14: Impact of the Size of Combined Cycle Unit on System Costs

Study Year	2010		2013	
Annual Peak Demand (MW)	**2362**		**2398**	
Annual Energy Demand (GWh)	**13381**		**13363**	
Wind Power Integration (MW)	**311 Opt 2**		**581**	
TUC CC Capacity (MW)	**125**	**150**	**125**	**150**
Energy Generation (GWh)	**13375.7**	**13377.2**	**13359.9**	**13361.0**
Thermal	11285.6	11283.0	10411.4	10405.0
Wind	907.0	907.0	1769.9	1769.9
Other Renewables	1183.1	1187.1	1178.6	1186.1
Interrupted and Unserved Load (GWh)	**5.3**	**3.8**	**3.1**	**2.0**
CO_2 Emissions (KT)	**10083.1**	**10050.7**	**9347.6**	**9323.7**
SO_2 Emissions (KT)	**70.9**	**70.4**	**67.5**	**67.2**
NO_x Emissions (KT)	**20.5**	**20.3**	**18.5**	**18.4**
Hg Emissions (Kg)	**33.7**	**33.6**	**28.6**	**28.6**
Total Costs (M$)	**728.1**	**723.4**	**901.1**	**895.5**
Generator Capital Payments	14.0	15.2	15.2	16.3
Fixed O&M Costs	70.0	70.0	74.3	74.3
Variable O&M Costs	13.4	13.6	13.3	13.4
Fuel Charges	396.1	390.8	426.3	420.3
Wind Energy Payments	81.8	81.8	161.9	161.9
CO2 Offset Costs	151.9	151.4	209.4	208.8
New Transmission Costs	0.0	0.0	0.0	0.0
Import Energy Costs	0.9	0.6	0.6	0.4

Table 7-15: Operational Variability for Wind Power Diversity/Concentration

Time Scale	Technical Issue	Without Wind Generation	600 MW in Six Zones	600 MW in Five Zones	600 MW in Four Zones	600 MW in Three Zones	600 MW in Two Zones	600 MW in One Zone
Yearly	Wind Capacity Factor							
	Annual (%)	--	36.47	37.10	37.72	35.77	31.86	31.86
	Winter (%)	--	41.50	41.21	40.74	38.99	35.49	35.49
	Summer (%)	--	31.52	33.05	34.75	32.60	28.29	28.29
	Annual Maximum Hourly Load (MW)	2439	2276	2264	2288	2268	2418	2418
	Annual Minimum Hourly Load (MW)	709	455	472	442	452	319	319
	Annual Hourly Load Variation (MW)	1730	1821	1792	1846	1816	2099	2099
Hours	Maximum Daily Variation (MW)	981.2	1220.6	1220.5	1277.9	1301.2	1405.8	1405.8
	Daily Incremental Variation (MW)	--	239.4	239.3	296.7	320.0	424.6	424.6
	Scheduling (3-hour delta), σ (MW)	183.6	182.9	184.6	188.7	189.0	200.0	200.0
	Largest 3-Hour Rise (MW)	499.1	563.3	603.4	651.9	642.1	733.7	733.7
	Largest 3-Hour Drop (MW)	-419.5	-517.2	-536.1	-570.7	-552.3	-653.2	-653.2
	Scheduling (1-hour delta), σ (MW)	78.9	84.7	87.2	91.7	93.5	106.5	106.5
	Largest 1-Hour Rise (MW)	309.2	325.4	350.3	383.2	372.7	490.2	490.2
	Largest 1-Hour Drop (MW)	-254.1	-271.7	-305.0	-313.5	-314.5	-427.5	-427.5
	Maximum Hourly Load Variation (MW)	301.7	391.7	442.0	469.9	446.5	617.3	617.3
Minutes	Load Following (10-minute delta), σ (MW)	18.1	30.6	33.9	38.9	39.0	48.6	48.6
	Largest 10-Minute Rise (MW)	131.0	227.2	258.2	322.6	346.5	516.3	516.3
	Largest 10-Minute Drop (MW)	-159.0	-198.5	-226.2	-282.2	-334.0	-498.8	-498.8
	Load Following Requirement (3*σ, MW)	54.4	91.7	101.7	116.7	117.0	145.8	145.8
	Incremental Requirement (MW/10-minute)	--	37.3	47.3	62.3	62.6	91.4	91.4
	Incremental Requirement (%)	--	68.5	86.9	114.4	115.0	167.9	167.9
	Load Following (5-minute delta), σ (MW)	11.4	21.2	23.7	27.4	27.4	34.3	34.3
	Largest 5-Minute Rise (MW)	98.8	249.8	300.5	375.8	354.1	524.2	524.2
	Largest 5-Minute Drop (MW)	-229.8	-231.7	-231.9	-283.7	-337.3	-513.6	-513.6
	Regulation (1-minute delta), σ (MW)	5.3	13.1	14.9	17.4	16.5	19.9	19.9
	Regulation Requirement (3*σ, MW)	15.9	39.3	44.7	52.2	49.5	59.7	59.7
	Incremental Requirement (MW/1-minute)	--	23.4	28.8	36.3	33.6	43.8	43.8
	Incremental Requirement (%)	--	147.0	181.2	228.4	211.4	275.6	275.6

Table 7-16: Adjusted Net Load Used in Day Ahead Unit Scheduling

Hour	January 28 Forecast Load	January 28 Most Likely Wind Power	January 28 Most Likely Net Load (MW)	January 28 Adjusted Wind Power	January 28 Adjusted Net Load	December 26 Forecast Load	December 26 Most Likely Wind Power	December 26 Most Likely Net Load (MW)	December 26 Adjusted Wind Power	December 26 Adjusted Net Load
1	1933	276	1657	304	1629	984	410	574	451	533
2	1938	276	1662	303	1634	899	405	494	445	454
3	1943	275	1668	303	1641	860	421	440	463	397
4	1947	275	1672	303	1645	847	407	441	447	400
5	1964	291	1673	320	1644	849	407	442	448	401
6	2022	323	1699	355	1667	887	423	464	465	422
7	2202	299	1902	269	1932	962	468	494	422	541
8	2392	274	2118	247	2145	1111	423	688	381	730
9	2439	339	2100	305	2134	1229	468	760	422	807
10	2423	321	2102	289	2134	1383	443	940	398	984
11	2372	361	2011	325	2047	1495	482	1013	434	1061
12	2337	332	2005	299	2038	1566	481	1085	433	1133
13	2274	313	1961	281	1993	1566	506	1059	456	1110
14	2108	401	1707	361	1747	1522	509	1013	458	1064
15	2077	412	1665	371	1706	1465	509	957	458	1007
16	2076	420	1656	378	1698	1483	423	1060	381	1102
17	2149	421	1728	379	1770	1578	382	1196	344	1234
18	2279	406	1873	366	1913	1672	373	1299	336	1337
19	2329	413	1916	372	1957	1640	496	1145	446	1194
20	2300	400	1900	360	1940	1603	492	1111	443	1160
21	2276	408	1867	367	1908	1558	499	1060	449	1110
22	2207	407	1799	367	1840	1494	466	1029	419	1075
23	2080	399	1681	439	1641	1362	393	969	432	929
24	2005	333	1672	367	1639	1207	431	776	474	733
Maxiumum	**2439**		**2118**		**2145**	**1672**		**1299**		**1337**
Minimum	**1933**		**1656**		**1629**	**847**		**440**		**397**
Variation	**506**		**461**		**516**	**825**		**860**		**939**

Table 7-17: Simplified Financial Analysis for a 50 MW Wind Plant Located in Sydney Zone

Installed Capacity		50	MW	Debt Interest	7.50%	
Annual Capacity Factor		43.59%		Debt Term	25	Years
Annual Energy Production		190,924	MWh	Escalation Rate	2.00%	
Energy Rate		90.0930	$/MWh	Discount Rate	8.21%	
Initial Costs Per kW		2,200	(2007$/kW)	Debt Amortization Rate	8.9711%	
Total Initial Cost		123,877,866	(2013$)	Debt Amortization Payment	$6,945,729	Per Year
Annual O&M Cost		2,477,557	(2013$)			
				Pre-Tax IRR	19.395%	
Debt	62.5%	77,423,666	$			
Equity	37.5%	46,454,200	$			

Year	Annual Debt Payment	Annual O&M Cost	Annual Energy Revenue	Annual EcoEnergy Credit	Pre-Tax Earning
2012					-46,454,200
2013	6,945,729	2,477,557	17,200,933	1,909,242	9,686,888
2014	6,945,729	2,527,108	17,200,933	1,909,242	9,637,337
2015	6,945,729	2,577,651	17,200,933	1,909,242	9,586,795
2016	6,945,729	2,629,204	17,200,933	1,909,242	9,535,242
2017	6,945,729	2,681,788	17,200,933	1,909,242	9,482,658
2018	6,945,729	2,735,423	17,200,933	1,909,242	9,429,022
2019	6,945,729	2,790,132	17,200,933	1,909,242	9,374,314
2020	6,945,729	2,845,935	17,200,933	1,909,242	9,318,511
2021	6,945,729	2,902,853	17,200,933	1,909,242	9,261,592
2022	6,945,729	2,960,910	17,200,933	1,909,242	9,203,535
2023	6,945,729	3,020,129	17,200,933		7,235,075
2024	6,945,729	3,080,531	17,200,933		7,174,672
2025	6,945,729	3,142,142	17,200,933		7,113,062
2026	6,945,729	3,204,985	17,200,933		7,050,219
2027	6,945,729	3,269,084	17,200,933		6,986,119
2028	6,945,729	3,334,466	17,200,933		6,920,738
2029	6,945,729	3,401,155	17,200,933		6,854,048
2030	6,945,729	3,469,178	17,200,933		6,786,025
2031	6,945,729	3,538,562	17,200,933		6,716,642
2032	6,945,729	3,609,333	17,200,933		6,645,870
2033	6,945,729	3,681,520	17,200,933		6,573,684
2034	6,945,729	3,755,150	17,200,933		6,500,053
2035	6,945,729	3,830,253	17,200,933		6,424,950
2036	6,945,729	3,906,858	17,200,933		6,348,345
2037	6,945,729	3,984,995	17,200,933		6,270,208

Table 7-18: Simplified Financial Analysis for a 50 MW Wind Plant Located in Truro Zone

Installed Capacity		50	MW	Debt Interest	7.50%	
Annual Capacity Factor		31.86%		Debt Term	25	Years
Annual Energy Production		139,547	MWh	Escalation Rate	2.00%	
Energy Rate		90.0930	$/MWh	Discount Rate	8.21%	
Initial Costs Per kW		2,200	(2007$/kW)	Debt Amortization Rate	8.9711%	
Total Initial Cost		123,877,866	(2013$)	Debt Amortization Payment	$6,945,729	Per Year
Annual O&M Cost		2,477,557	(2013$)			
				Pre-Tax IRR	5.280%	
Debt	62.5%	77,423,666	$			
Equity	37.5%	46,454,200	$			

Year	Annual Debt Payment	Annual O&M Cost	Annual Energy Revenue	Annual EcoEnergy Credit	Pre-Tax Earning
2012					-46,454,200
2013	6,945,729	2,477,557	12,572,189	1,395,468	4,544,371
2014	6,945,729	2,527,108	12,572,189	1,395,468	4,494,819
2015	6,945,729	2,577,651	12,572,189	1,395,468	4,444,277
2016	6,945,729	2,629,204	12,572,189	1,395,468	4,392,724
2017	6,945,729	2,681,788	12,572,189	1,395,468	4,340,140
2018	6,945,729	2,735,423	12,572,189	1,395,468	4,286,504
2019	6,945,729	2,790,132	12,572,189	1,395,468	4,231,796
2020	6,945,729	2,845,935	12,572,189	1,395,468	4,175,993
2021	6,945,729	2,902,853	12,572,189	1,395,468	4,119,075
2022	6,945,729	2,960,910	12,572,189	1,395,468	4,061,017
2023	6,945,729	3,020,129	12,572,189		2,606,331
2024	6,945,729	3,080,531	12,572,189		2,545,929
2025	6,945,729	3,142,142	12,572,189		2,484,318
2026	6,945,729	3,204,985	12,572,189		2,421,475
2027	6,945,729	3,269,084	12,572,189		2,357,376
2028	6,945,729	3,334,466	12,572,189		2,291,994
2029	6,945,729	3,401,155	12,572,189		2,225,305
2030	6,945,729	3,469,178	12,572,189		2,157,281
2031	6,945,729	3,538,562	12,572,189		2,087,898
2032	6,945,729	3,609,333	12,572,189		2,017,127
2033	6,945,729	3,681,520	12,572,189		1,944,940
2034	6,945,729	3,755,150	12,572,189		1,871,310
2035	6,945,729	3,830,253	12,572,189		1,796,207
2036	6,945,729	3,906,858	12,572,189		1,719,602
2037	6,945,729	3,984,995	12,572,189		1,641,464

Table 7-19: Simplified Sensitivity Analysis for a 50 MW Wind Plant Located in Sydney Zone

Installed Capacity (MW)	50	Debt Interest	7.50%
Expected Capacity Factor	43.59%	Debt Term (Year)	25
Annual Energy Production (MWh)	190,924	Escalation Rate	2.00%
Energy Rate ($/MWh)	90.0930	Discount Rate	8.21%
Annual O&M Cost (of Capital)	2.00%		

Debt	62.5%
Equity	37.5%

Energy Curtailment	Annual Capacity Factor	Project Unit Cost (2007$/kW)		
		2200	2500	2800
		Project Initial Investment (2007M$)		
(%)	(%)	110	125	140
		Pre-Tax IRR		
0	43.59%	19.395%	13.706%	8.696%
5	41.41%	17.082%	11.458%	6.309%
10	39.23%	14.691%	9.056%	3.568%

Table 7-20: Simplified Sensitivity Analysis for a 50 MW Wind Plant Located in Truro Zone

Installed Capacity (MW)	50	Debt Interest	7.50%
Expected Capacity Factor	31.86%	Debt Term (Year)	25
Annual Energy Production (MWh)	139,547	Escalation Rate	2.00%
Energy Rate ($/MWh)	90.0930	Discount Rate	8.21%
Annual O&M Cost (of Capital)	2.00%		

Debt	62.5%
Equity	37.5%

Energy Curtailment	Annual Capacity Factor	Project Unit Cost (2007$/kW)		
		2200	2500	2800
		Project Initial Investment (2007M$)		
(%)	(%)	110	125	140
		Pre-Tax IRR		
0	31.86%	5.280%	-2.941%	--
5	30.27%	2.552%	--	--
10	28.67%	-0.995%	--	--

Note: Results are indicative not definitive.

Figure 7-1: Scatter of 581 MW Wind Power Generation

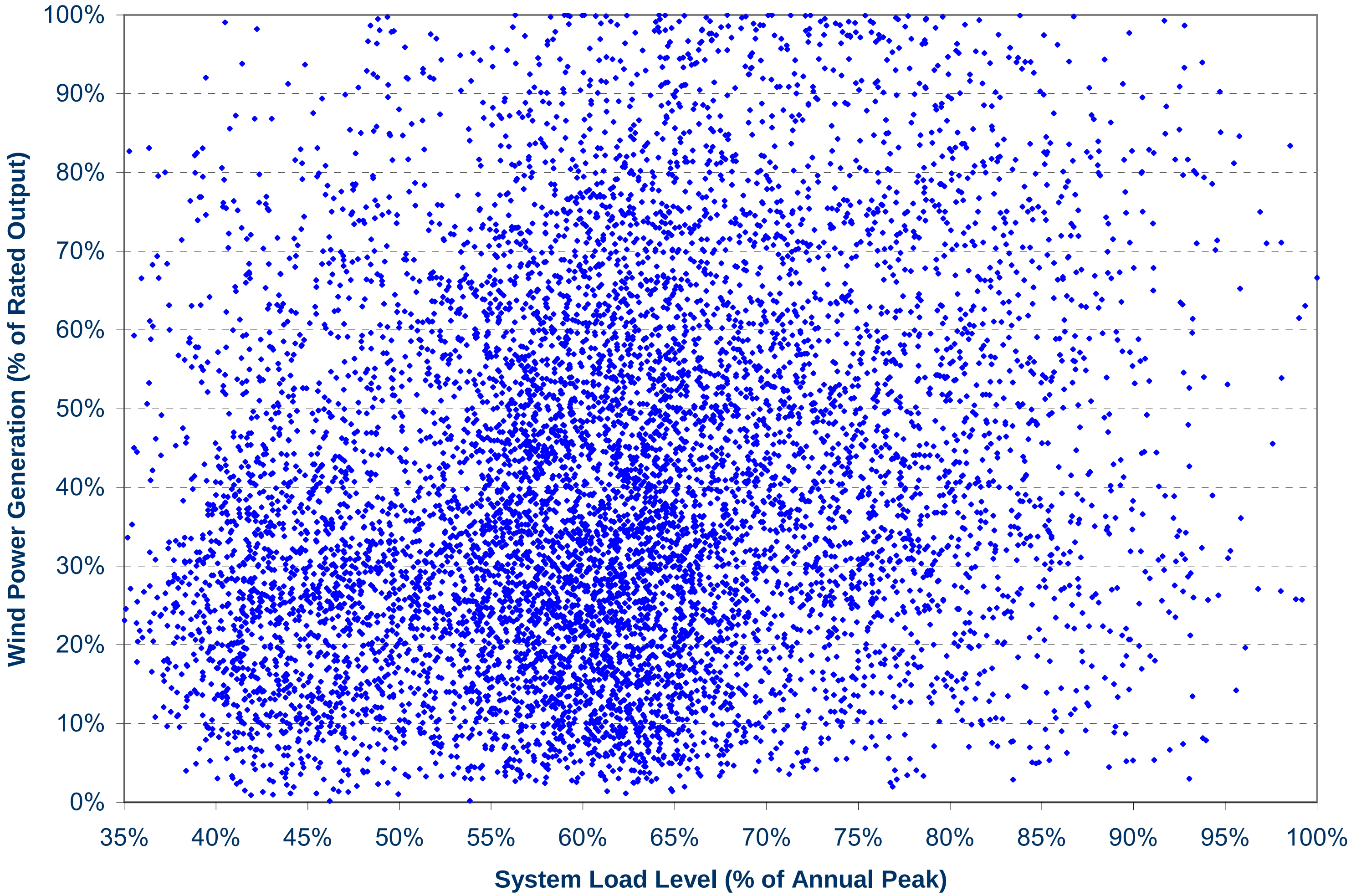


Figure 7-2: Occurrence Frequency of 581 MW Wind Power Generation

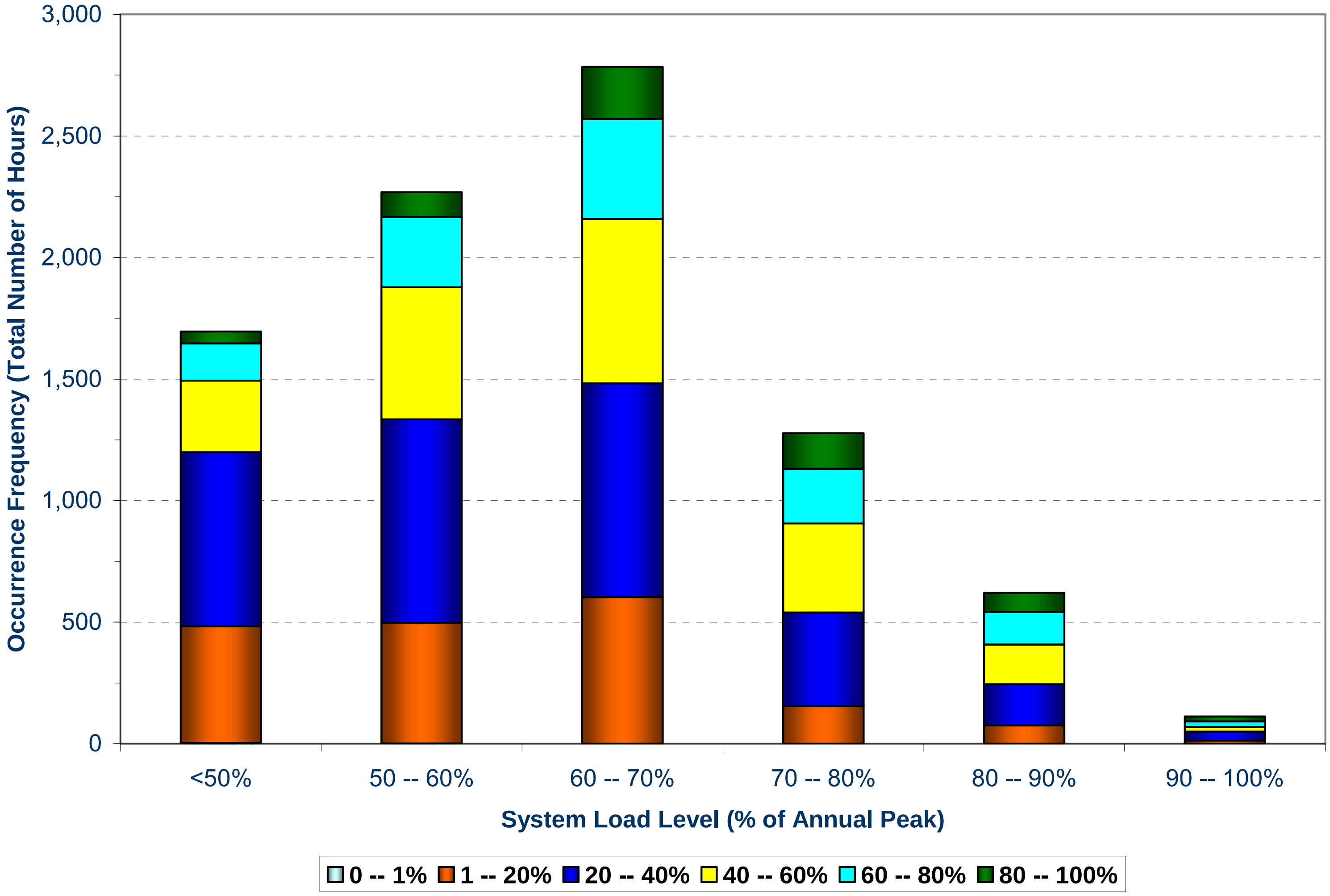


Figure 7-3: 581 MW Wind Power Generation

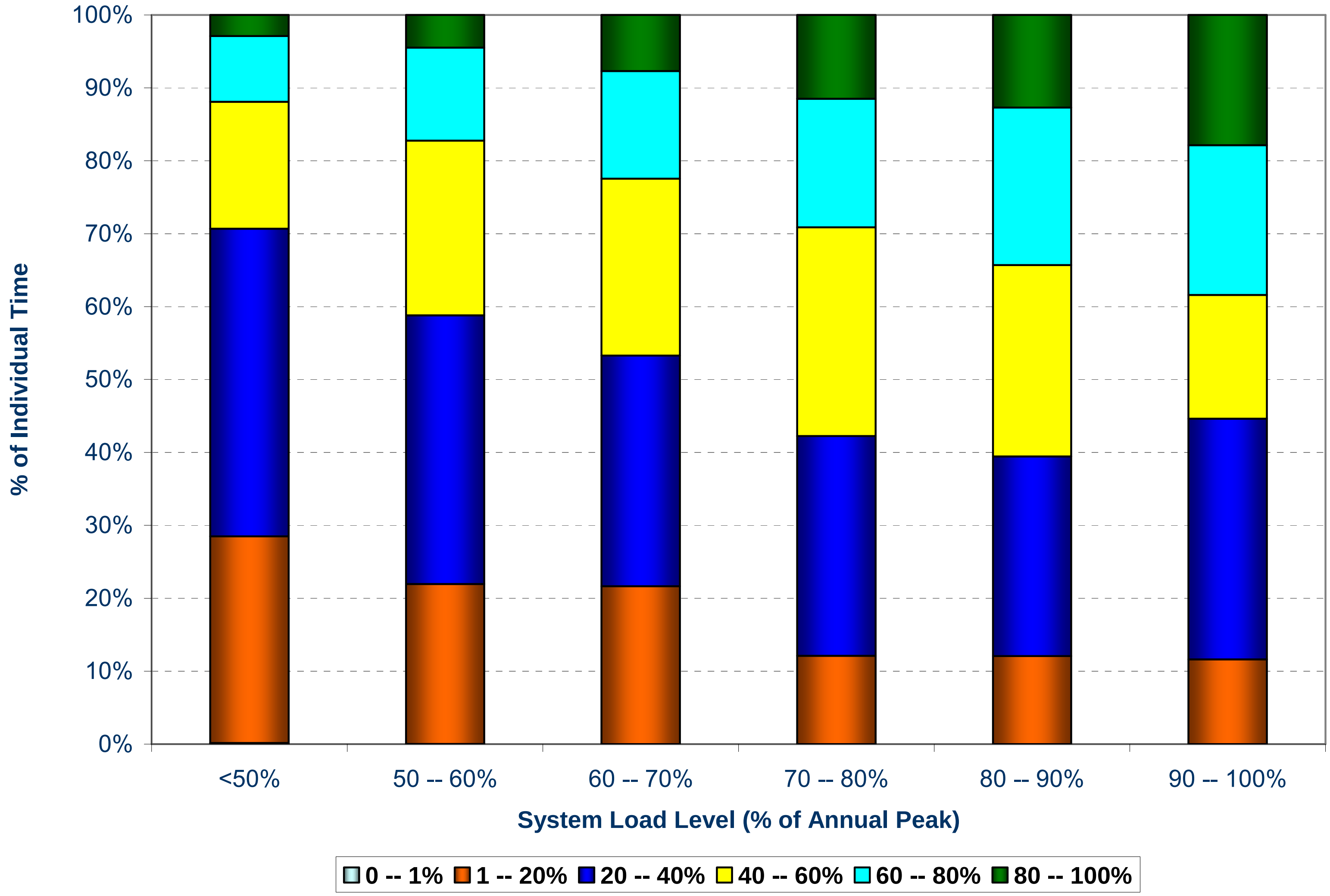


Figure 7-4: 1-minute Load Variation in 2020 – 581 MW Wind Power

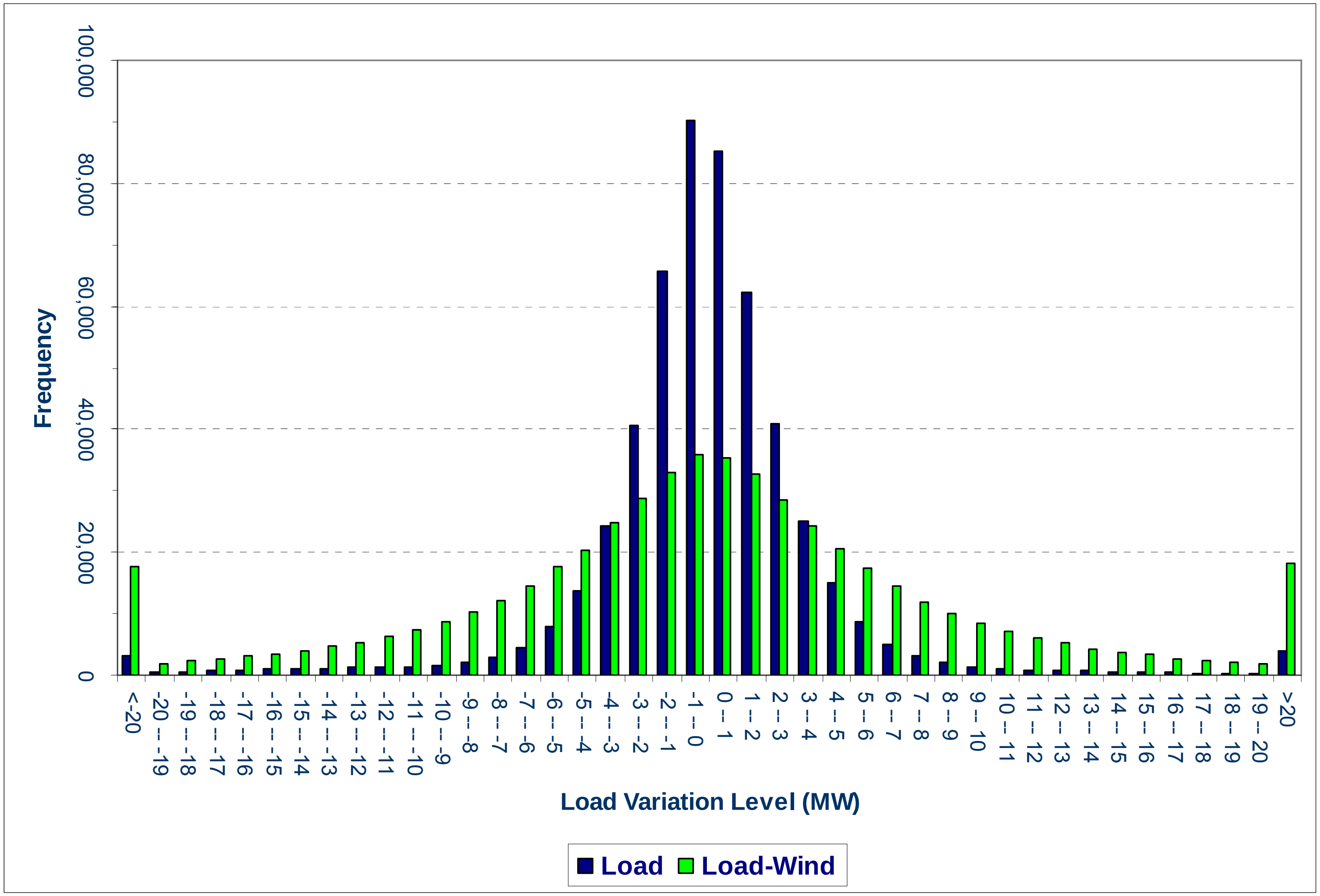


Figure 7-5: 10-minute Load Variation in 2020 – 581 MW Wind Power

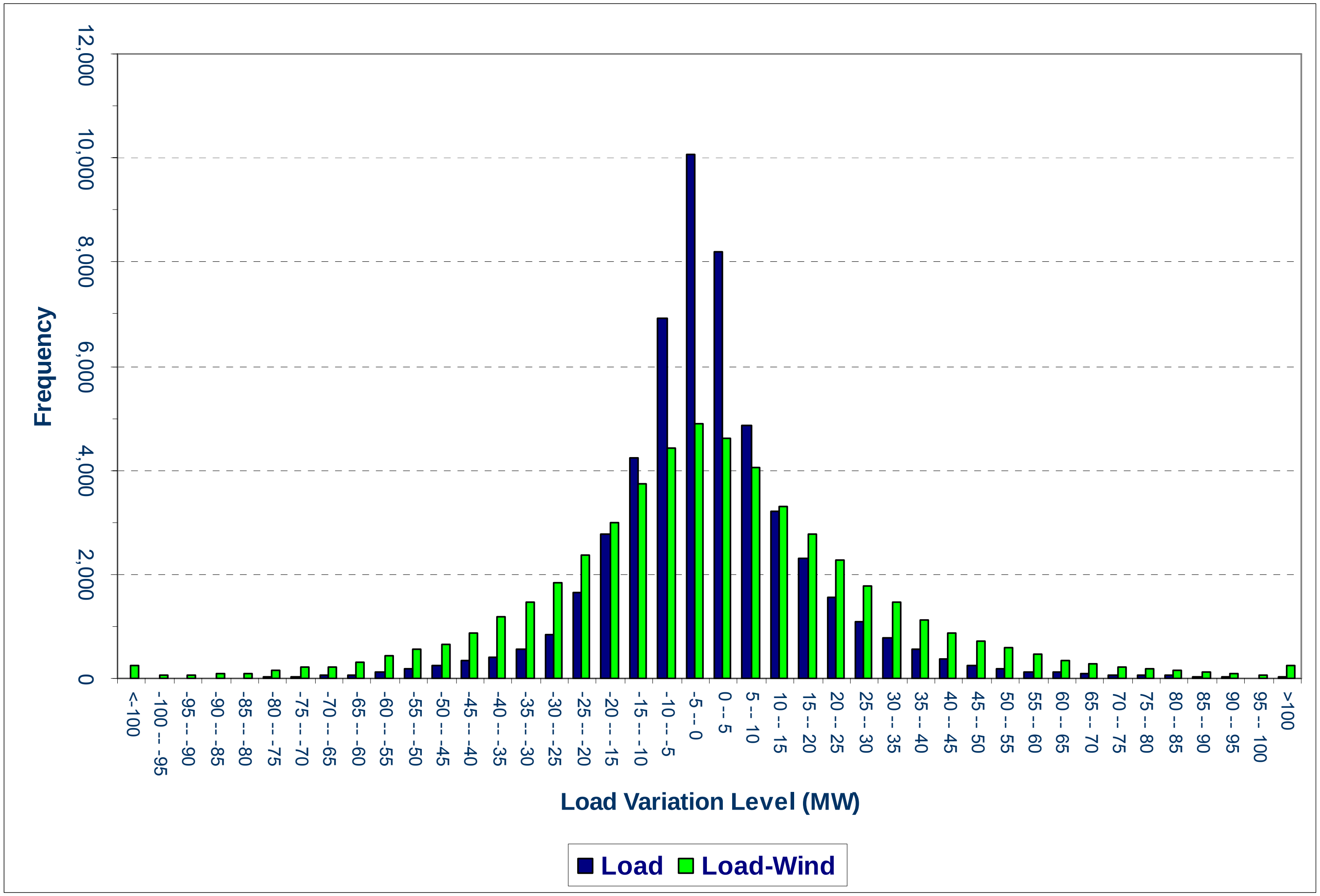


Figure 7-6: Occurrence Frequency of 781 MW Wind Power Generation – Option 1

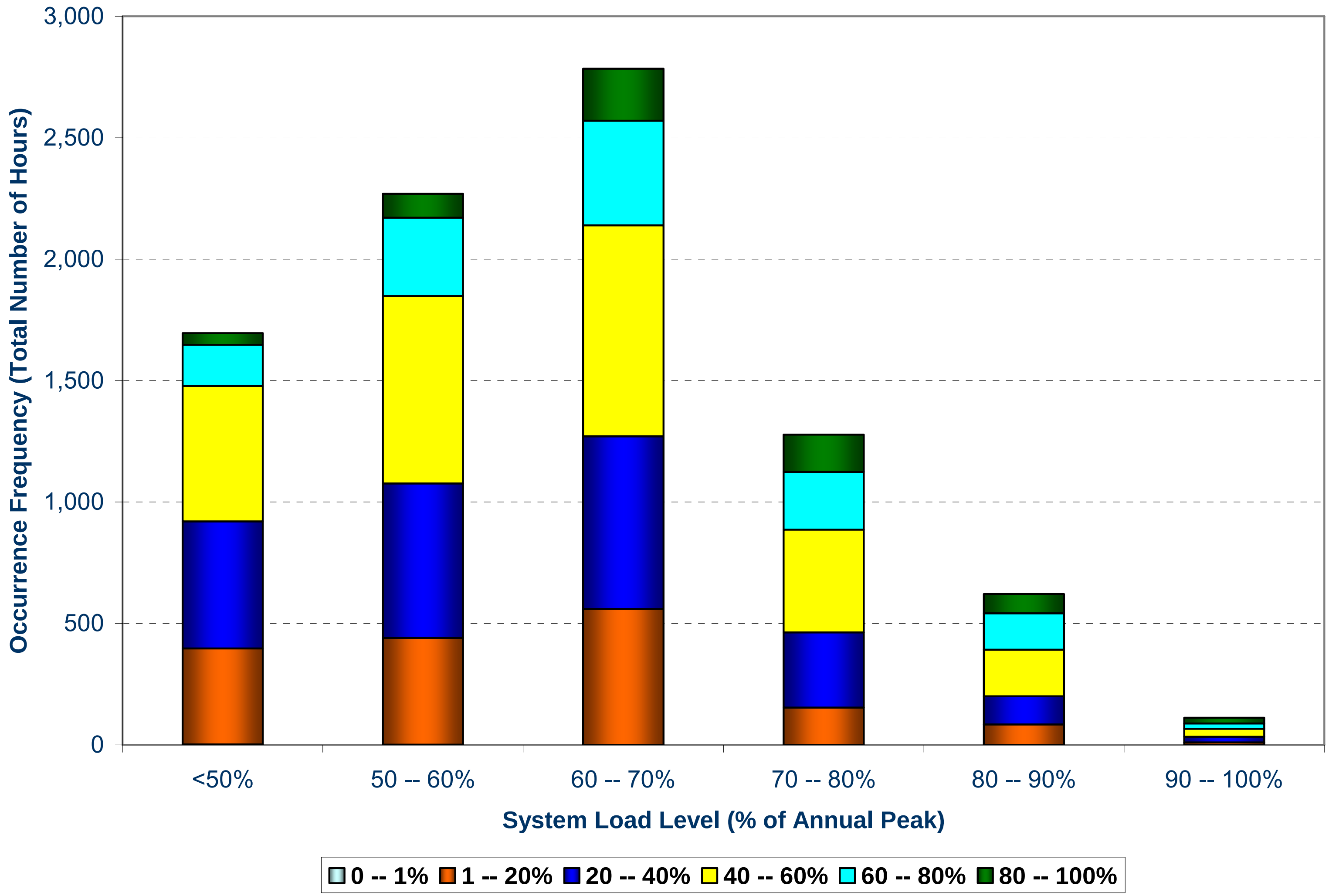


Figure 7-7: 781 MW Wind Power Generation – Option 1

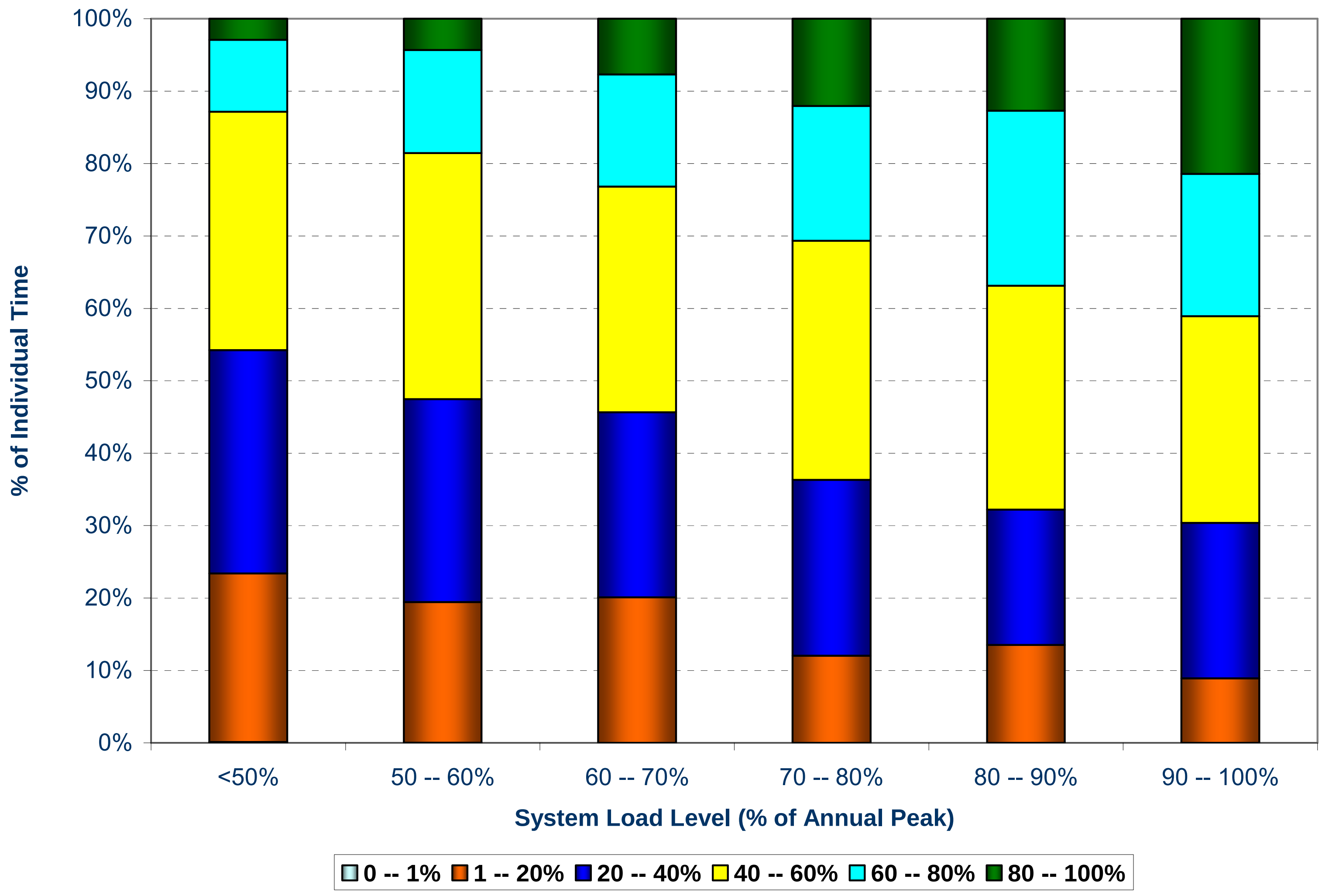


Figure 7-8: Occurrence Frequency of 781 MW Wind Power Generation – Option 2

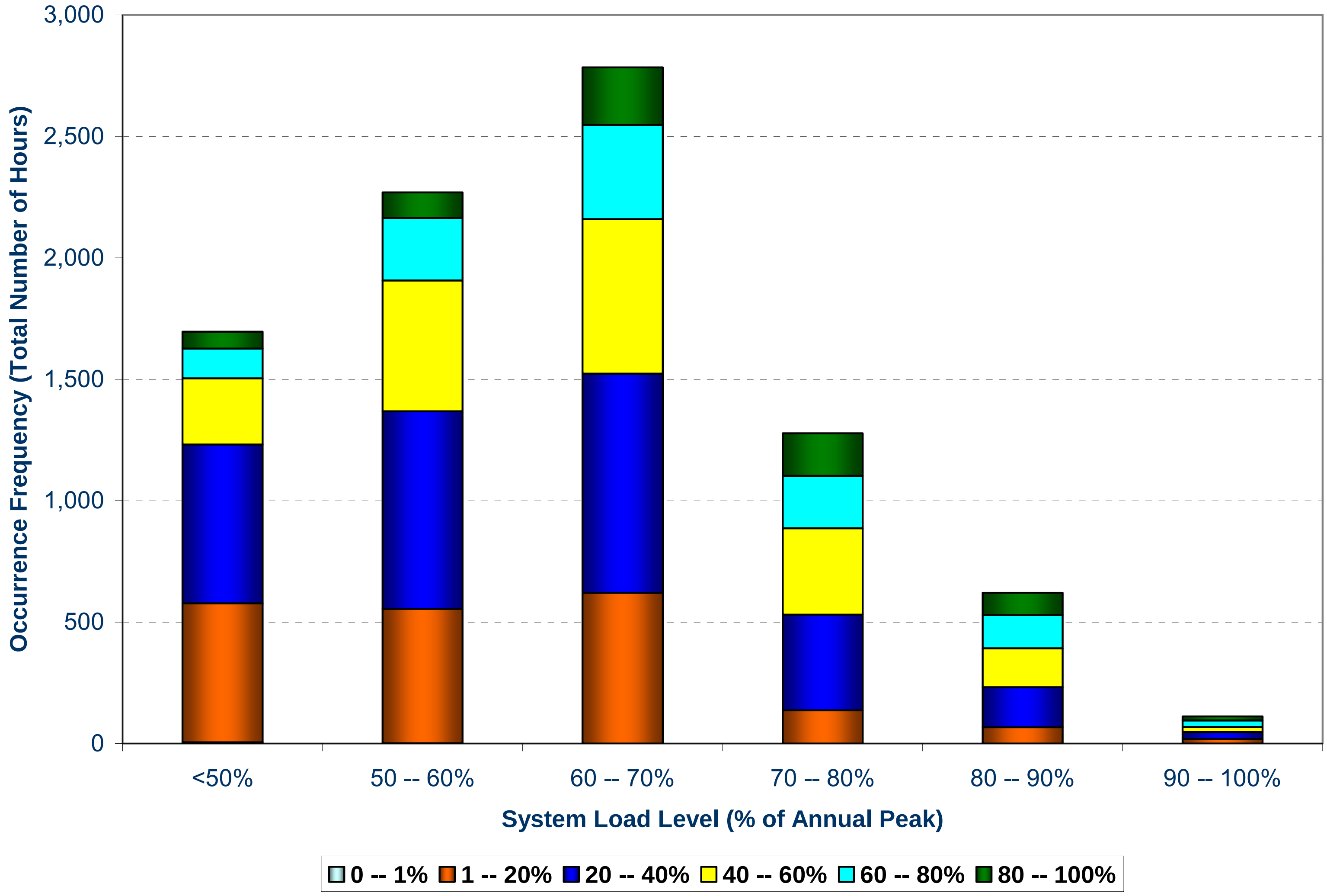


Figure 7-9: 781 MW Wind Power Generation – Option 2

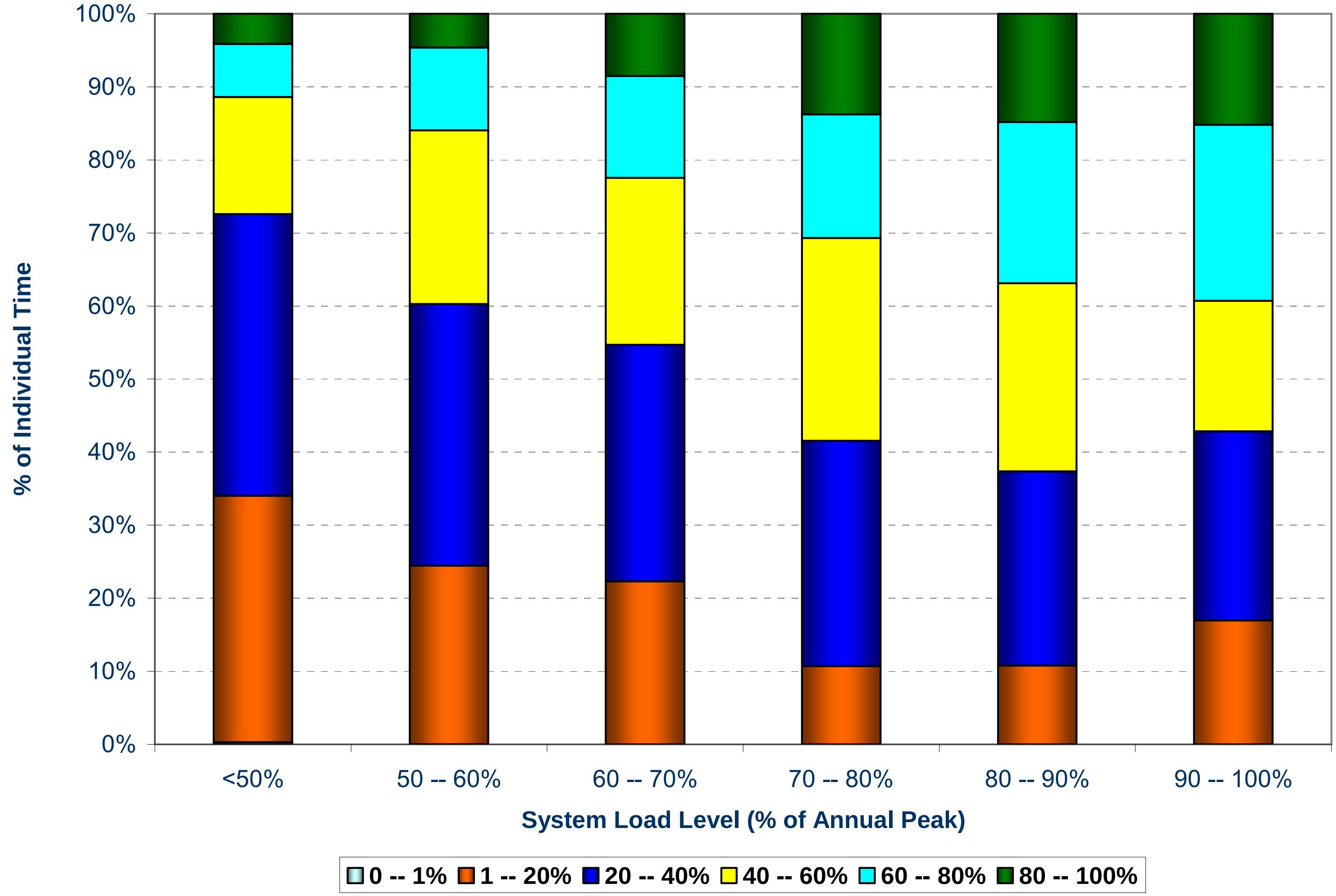


Figure 7-10: Occurrence Frequency of 981 MW Wind Power Generation – Option 1

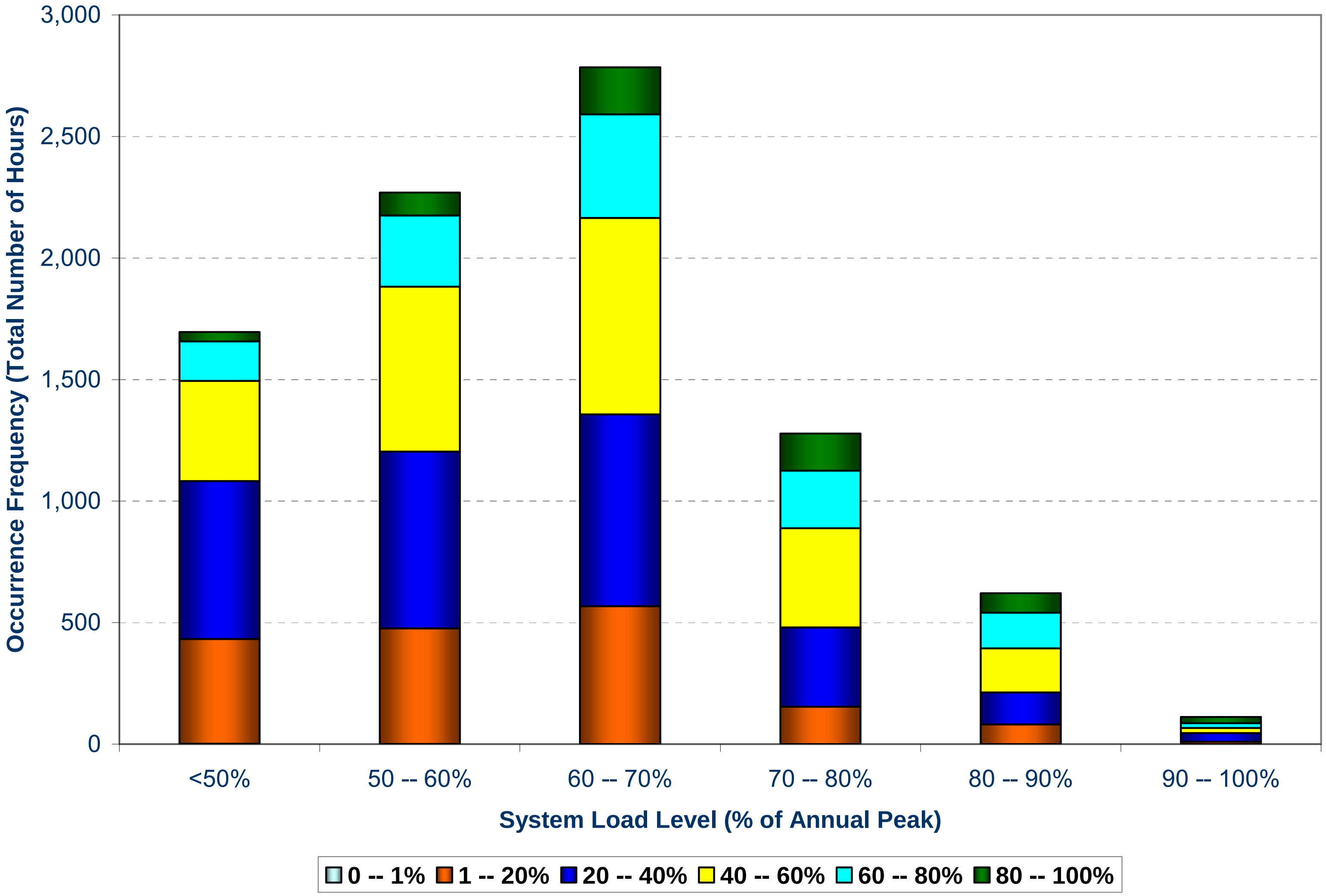


Figure 7-11: 981 MW Wind Power Generation – Option 1

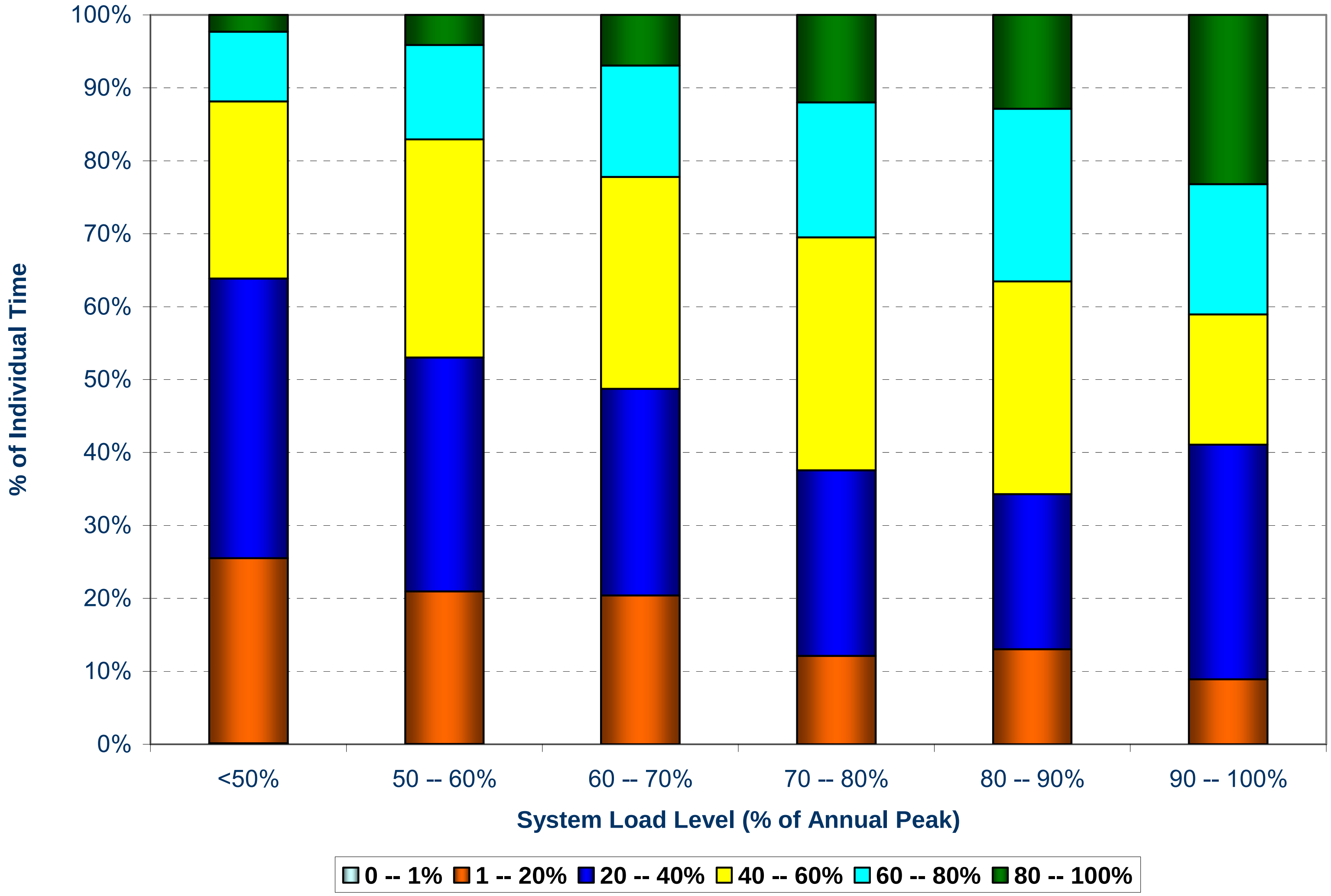


Figure 7-12: Occurrence Frequency of 981 MW Wind Power Generation – Option 2

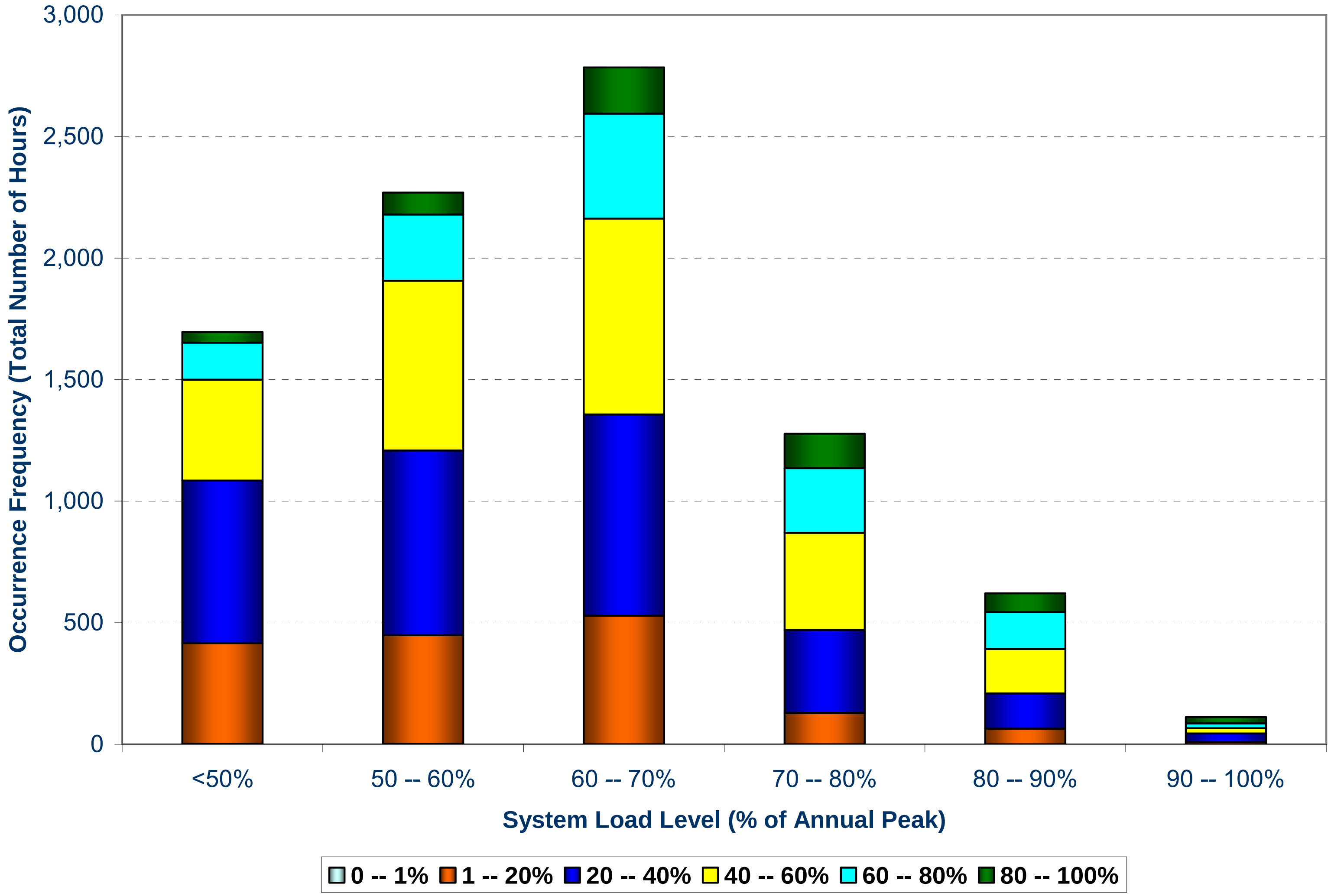


Figure 7-13: 981 MW Wind Power Generation – Option 2

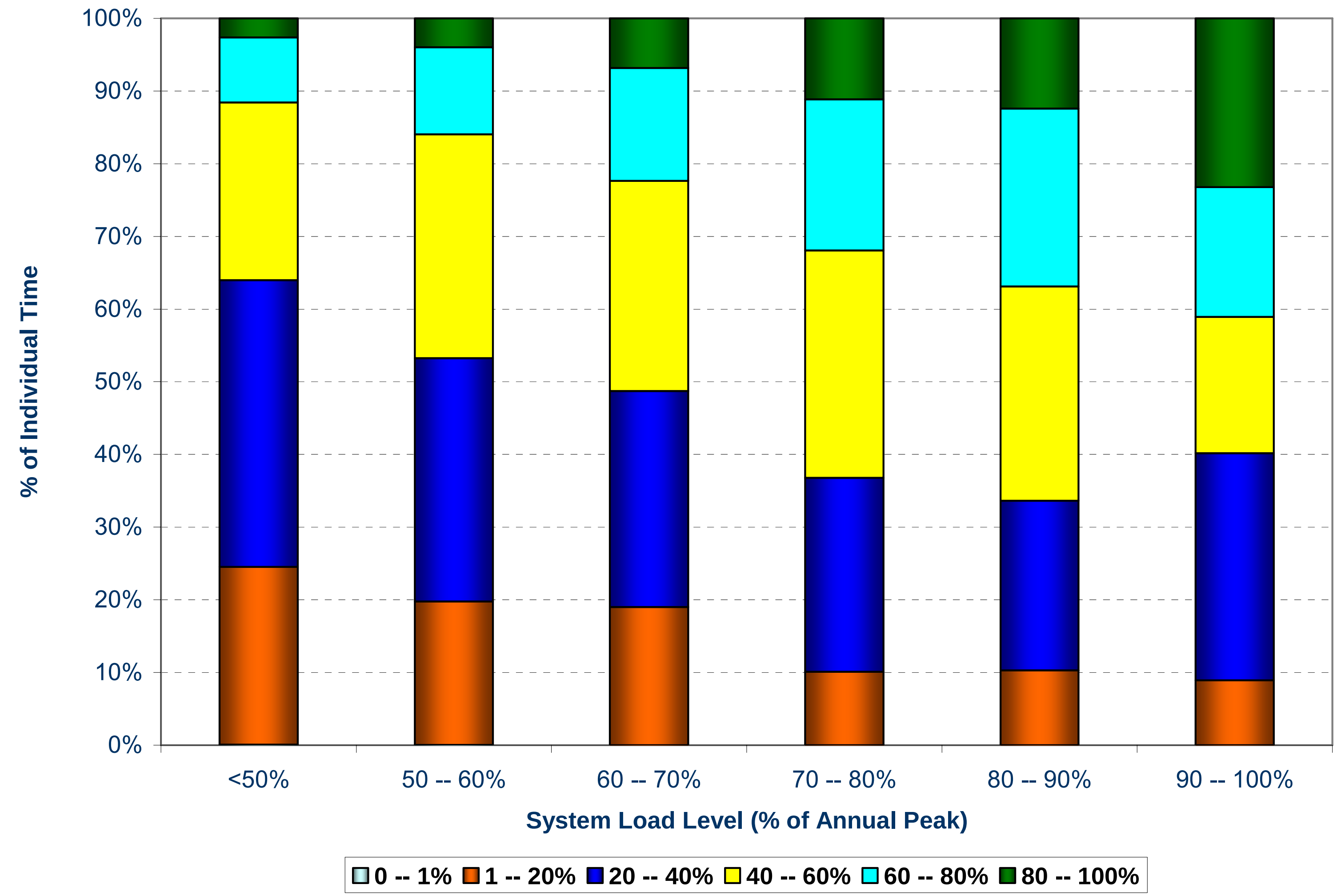


Figure 7-14: 1-minute Load Variation in 2020 – 781 MW Wind Power (Option 1)

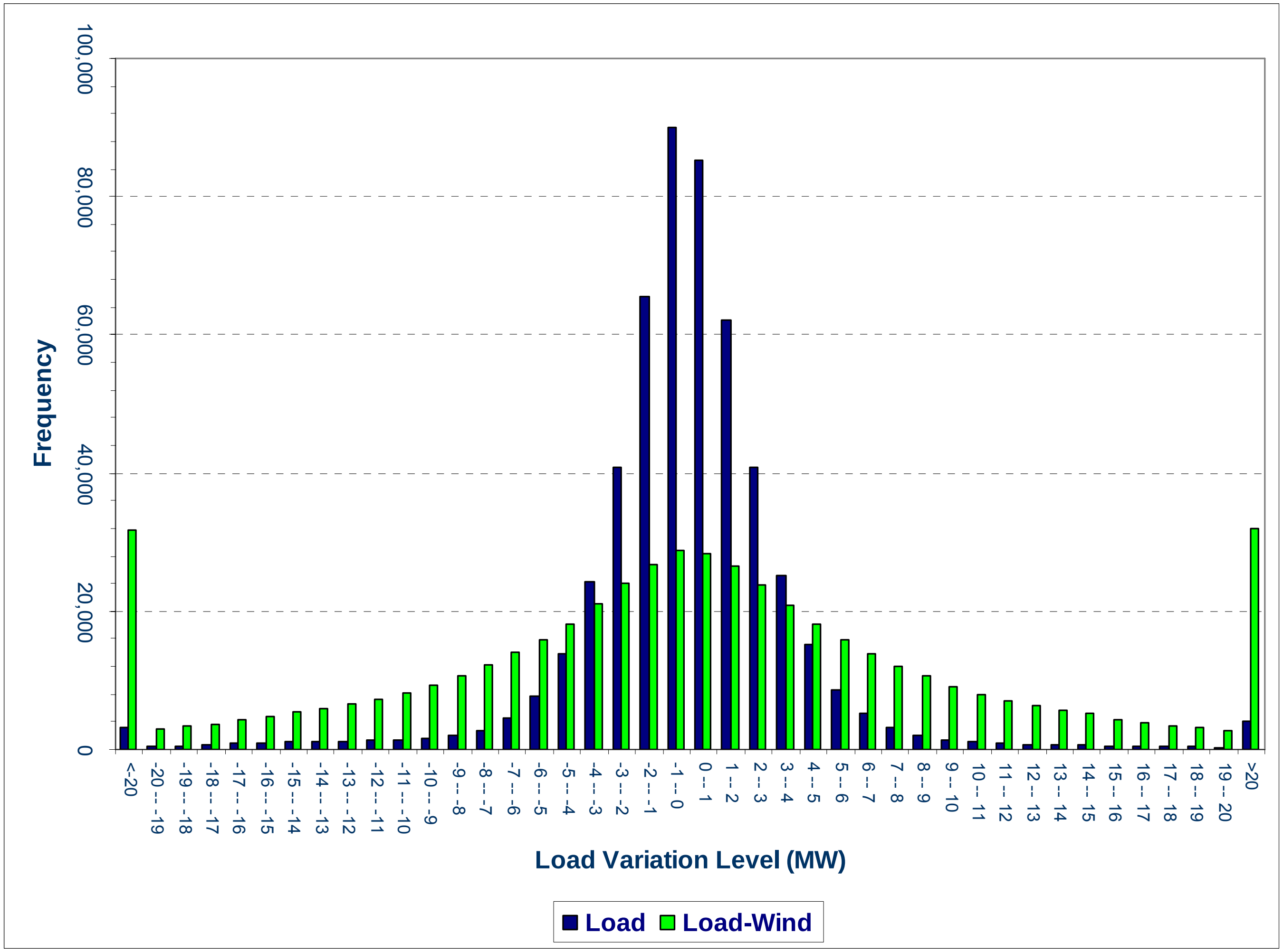


Figure 7-15: 10-minute Load Variation in 2020 – 781 MW Wind Power (Option 1)

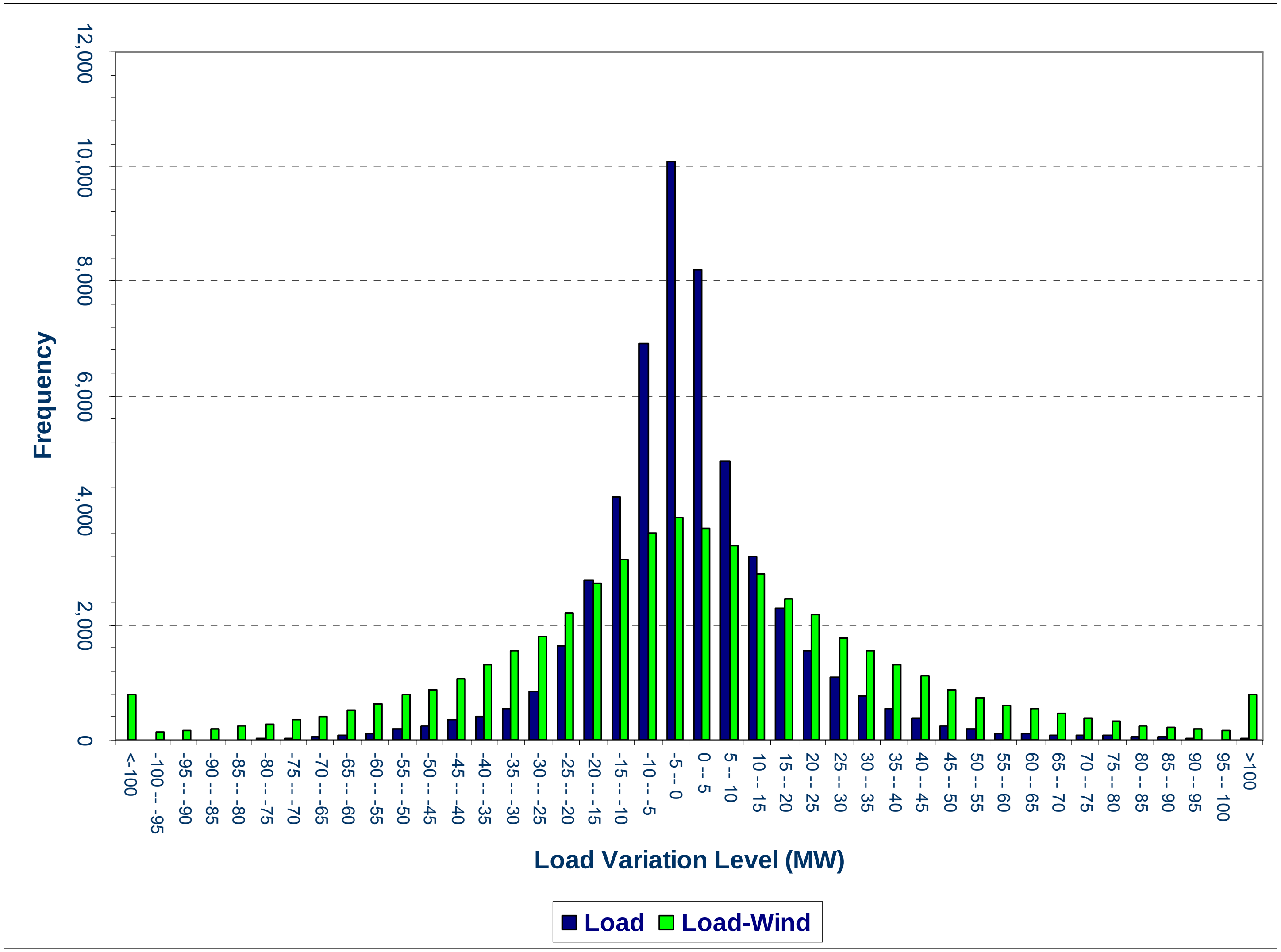


Figure 7-16: 1-minute Load Variation in 2020 – 781 MW Wind Power (Option 2)

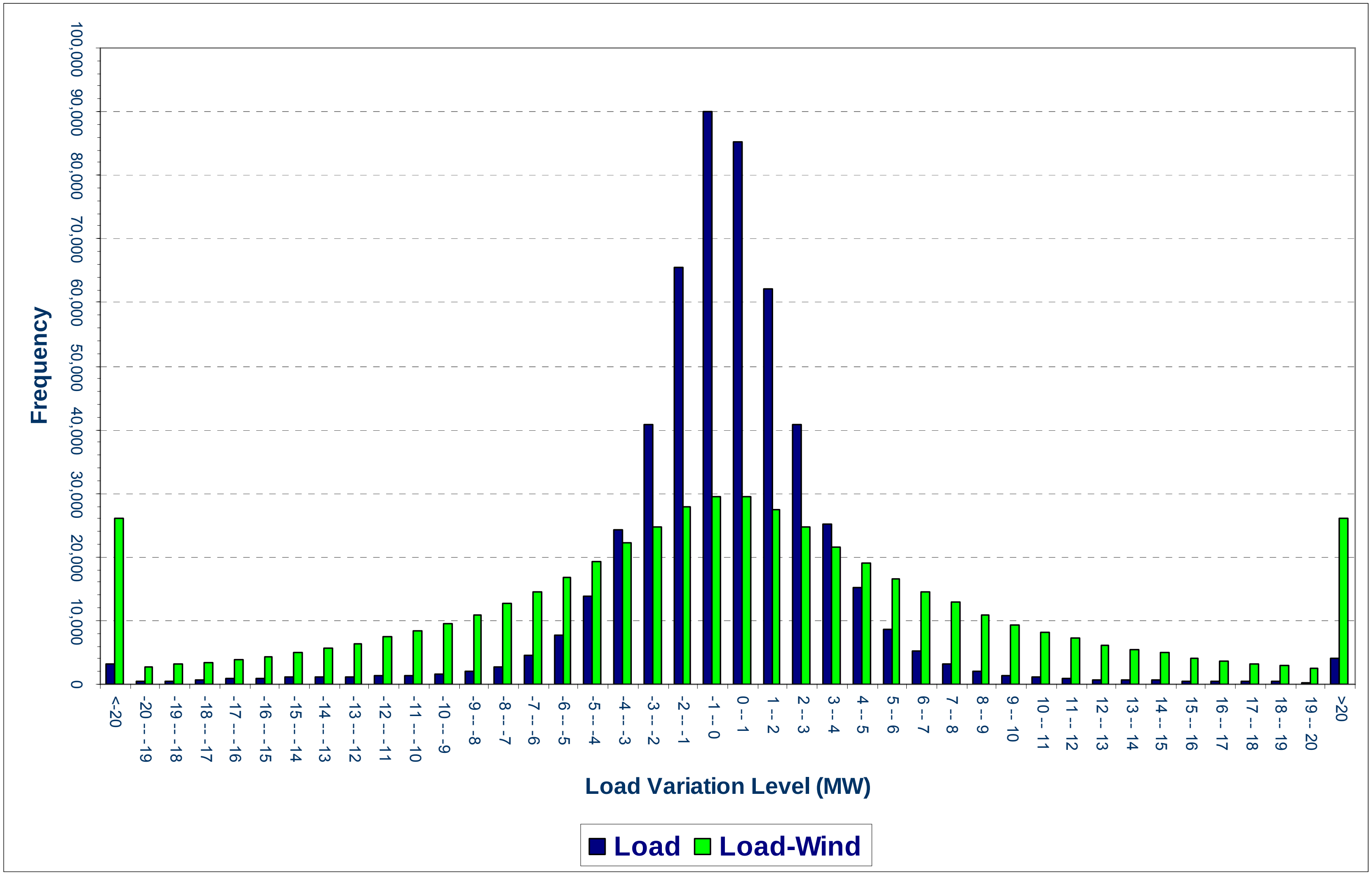


Figure 7-17: 10-minute Load Variation in 2020 – 781 MW Wind Power (Option 2)

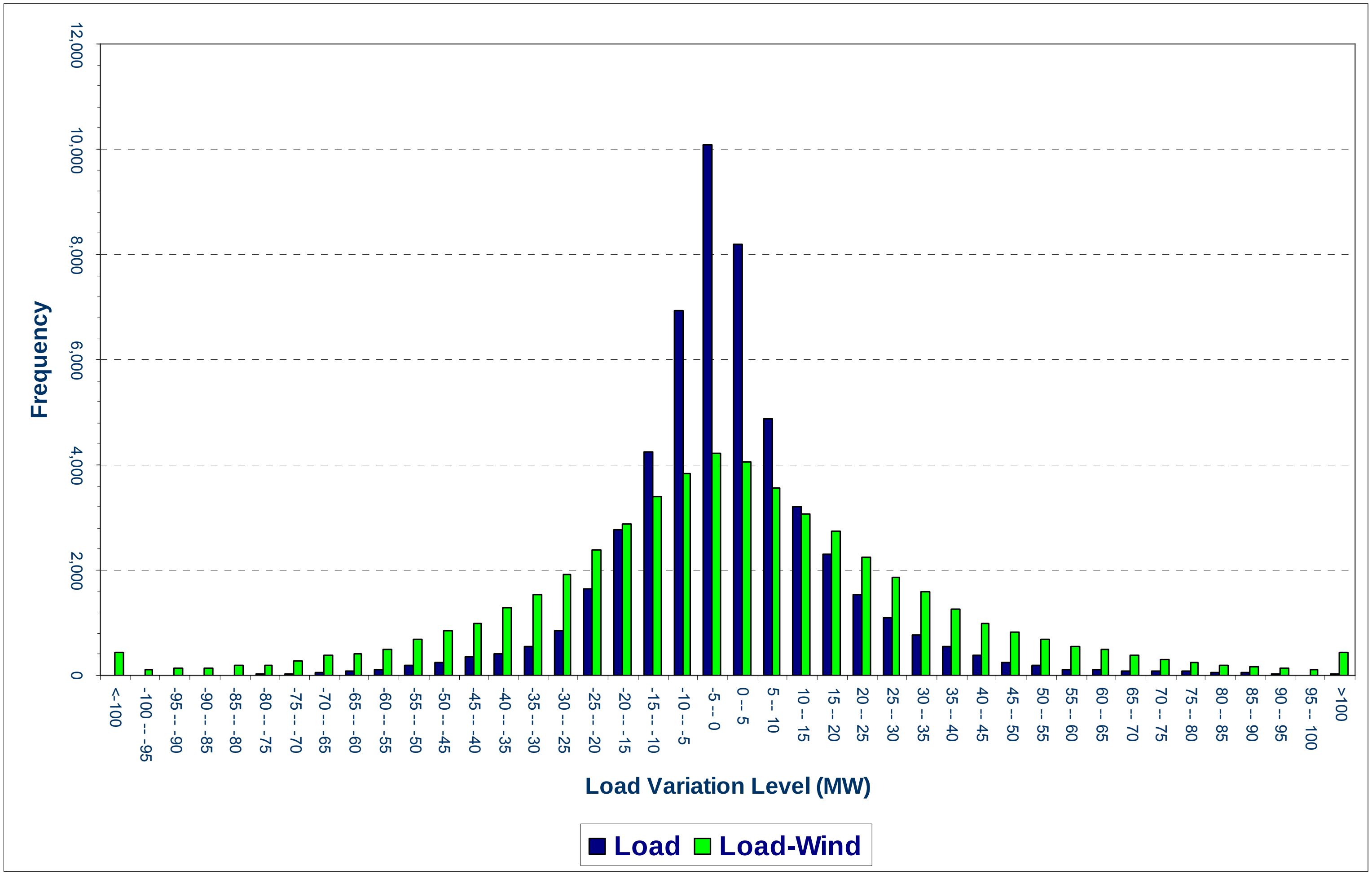


Figure 7-18: 1-minute Load Variation in 2020 – 981 MW Wind Power (Option 1)

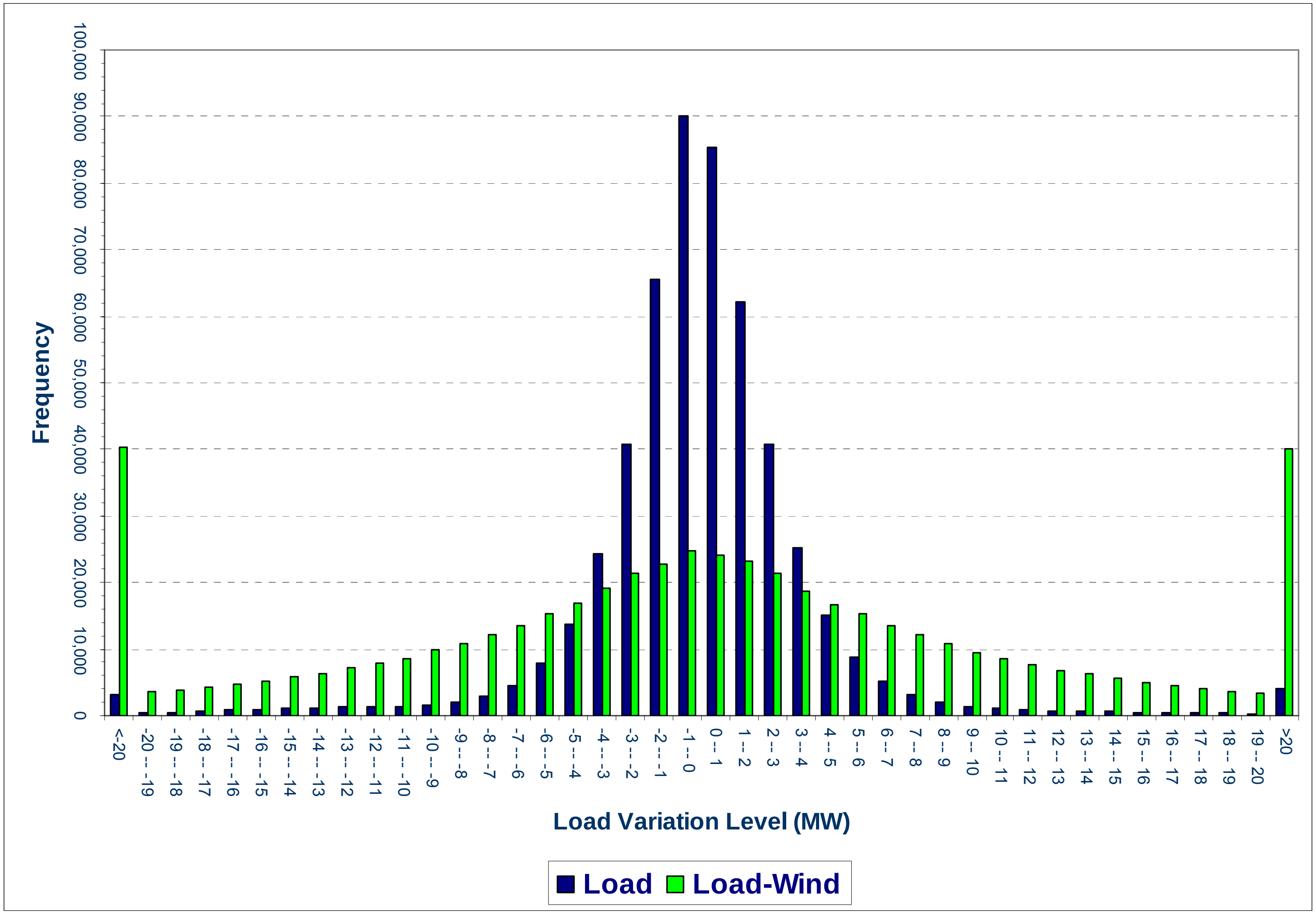


Figure 7-19: 10-minute Load Variation in 2020 – 981 MW Wind Power (Option 1)

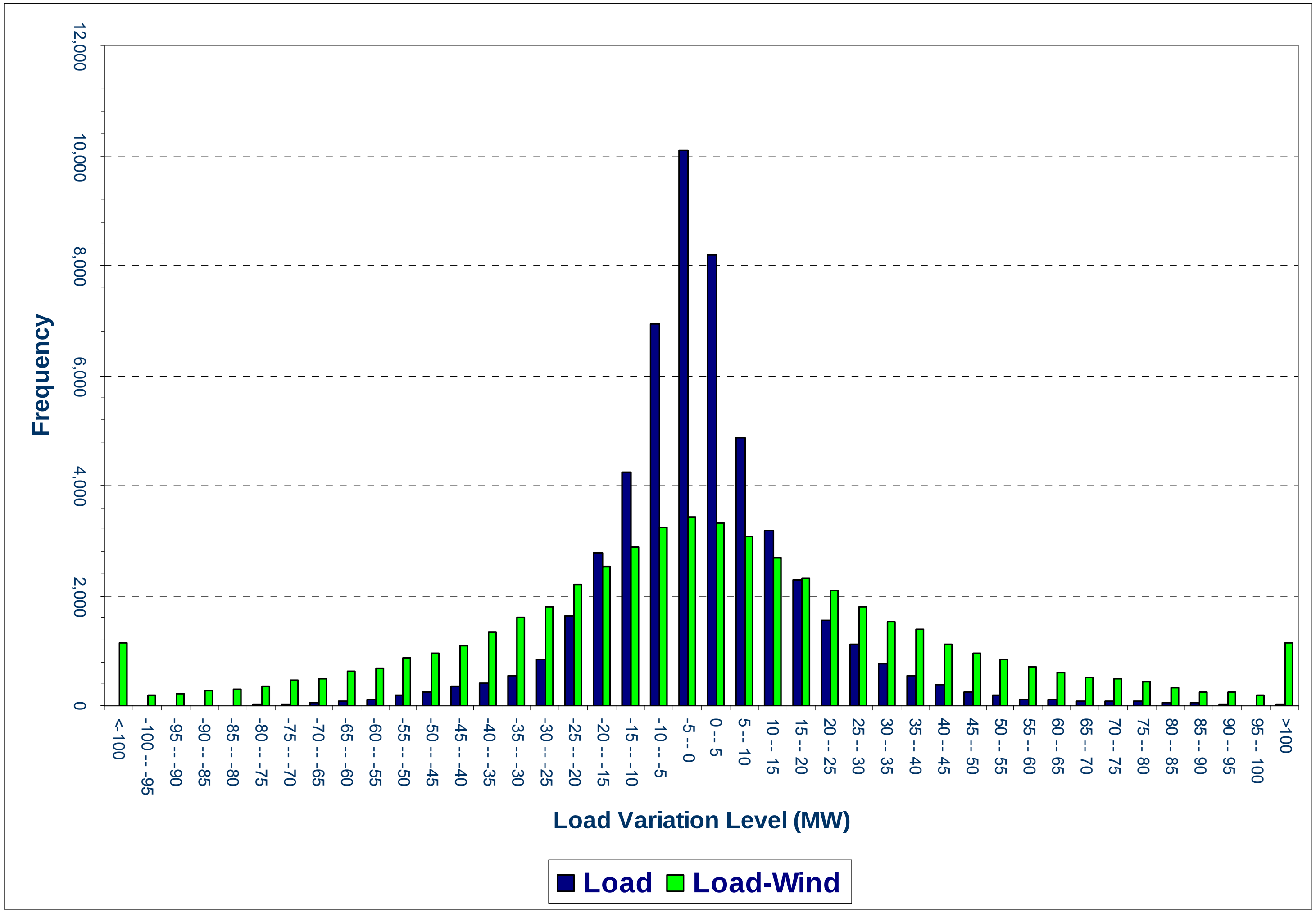


Figure 7-20: 1-minute Load Variation in 2020 – 981 MW Wind Power (Option 2)

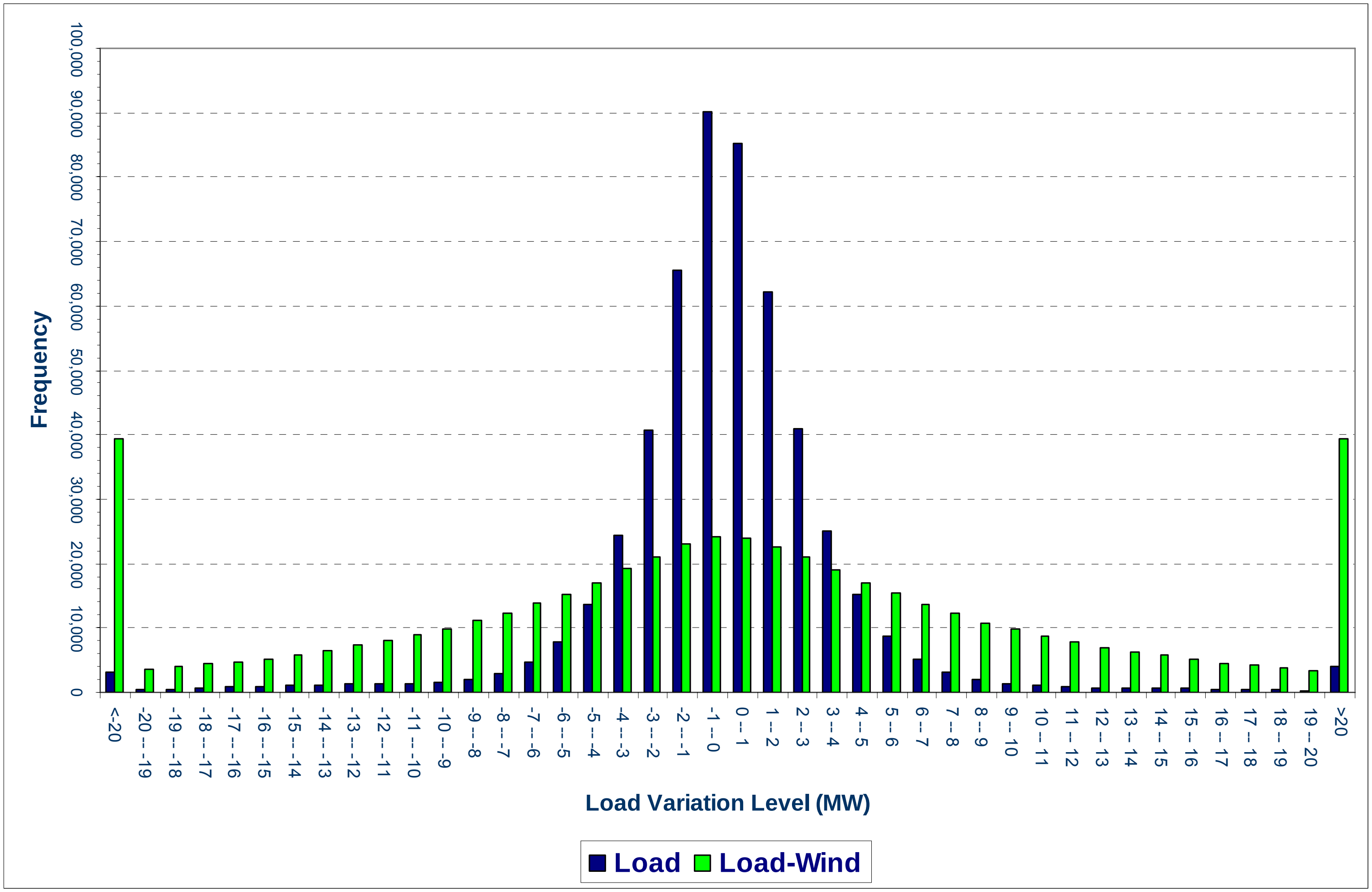


Figure 7-21: 10-minute Load Variation in 2020 – 981 MW Wind Power (Option 2)

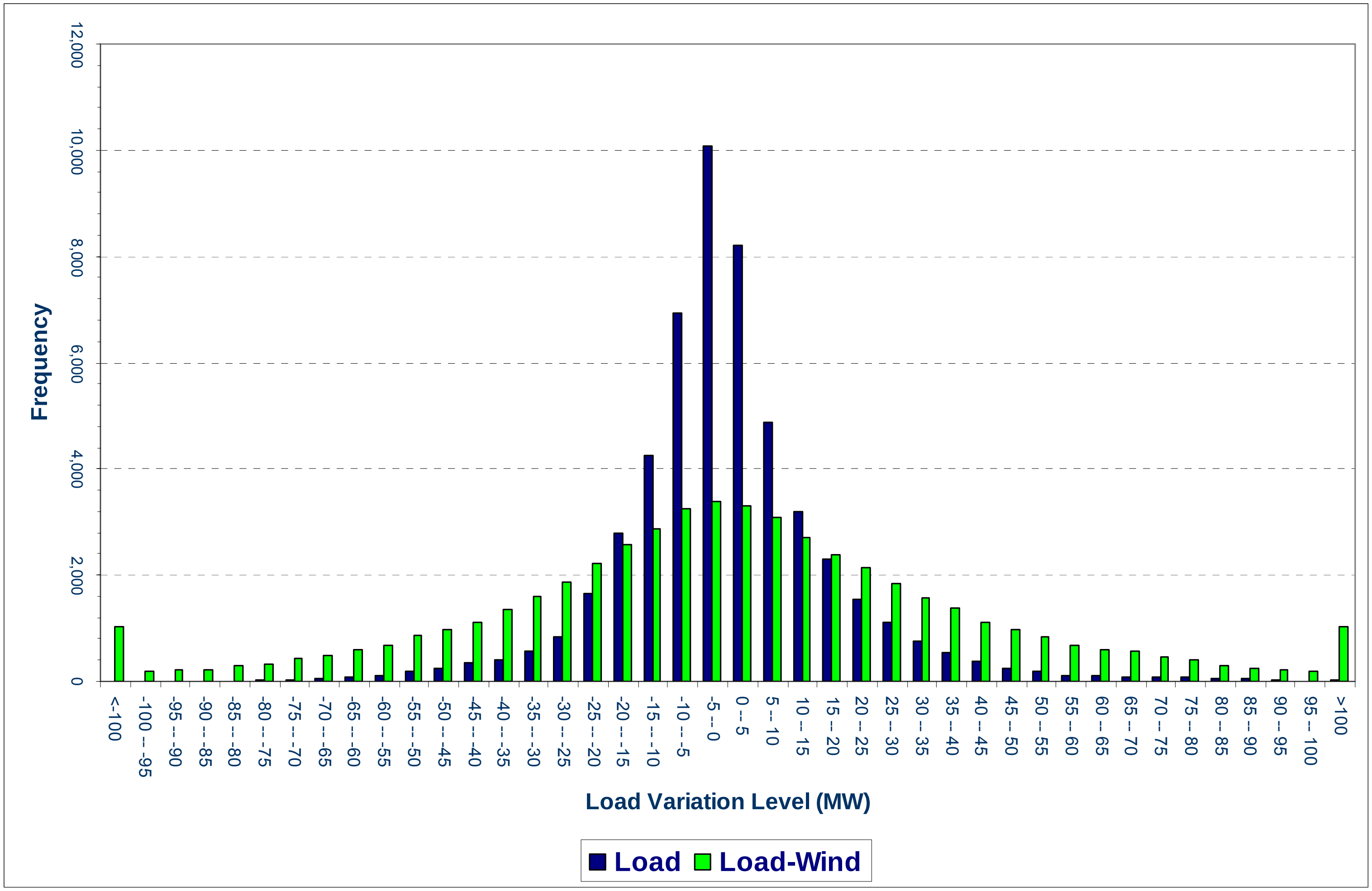


Figure 7-22: System Costs and GHG Emissions in 2020

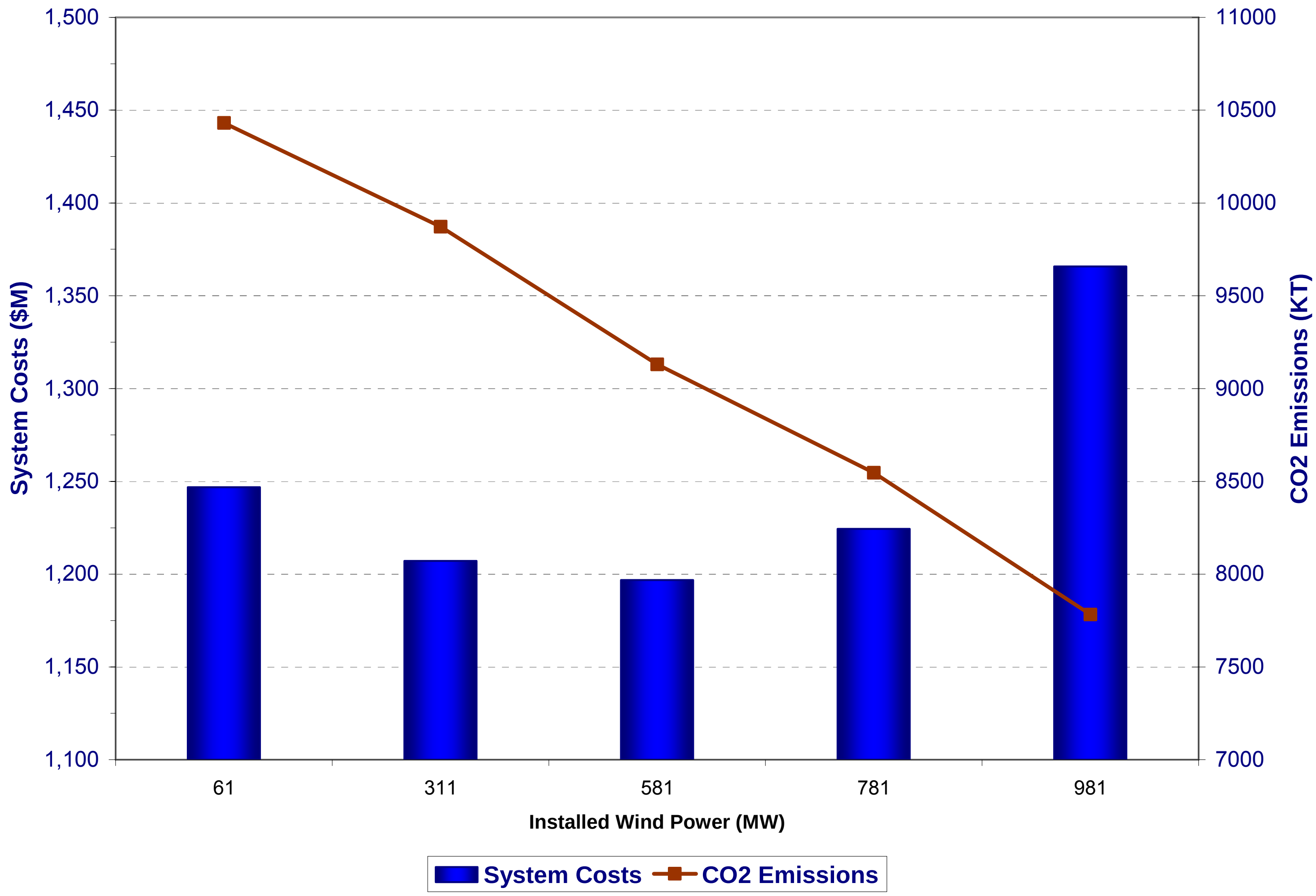


Figure 7-23: System Costs and GHG Emissions in 2020 – Without Emissions Offset

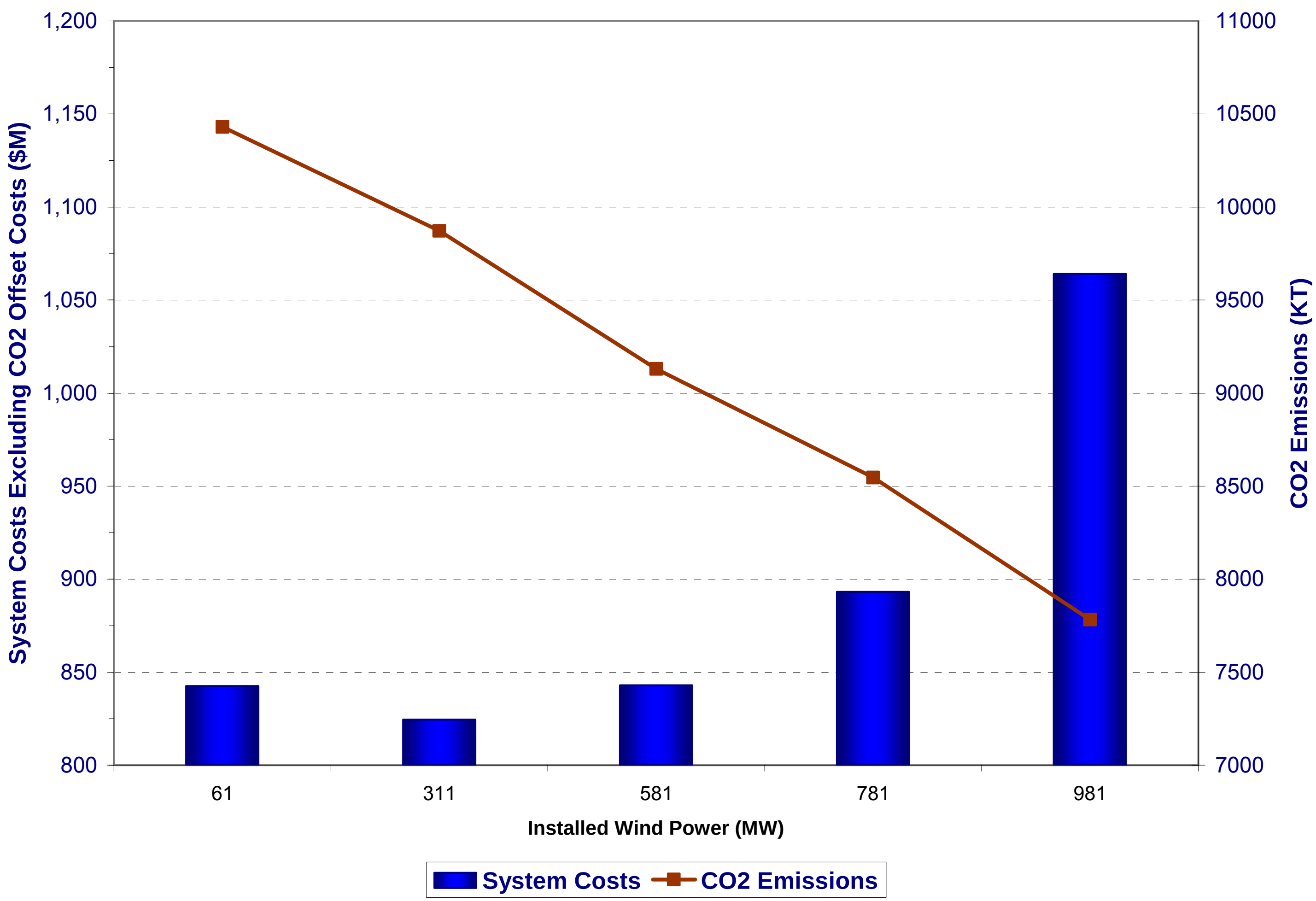


Figure 7-24: Relationship Between System Costs and CO_2 Emissions Reduction

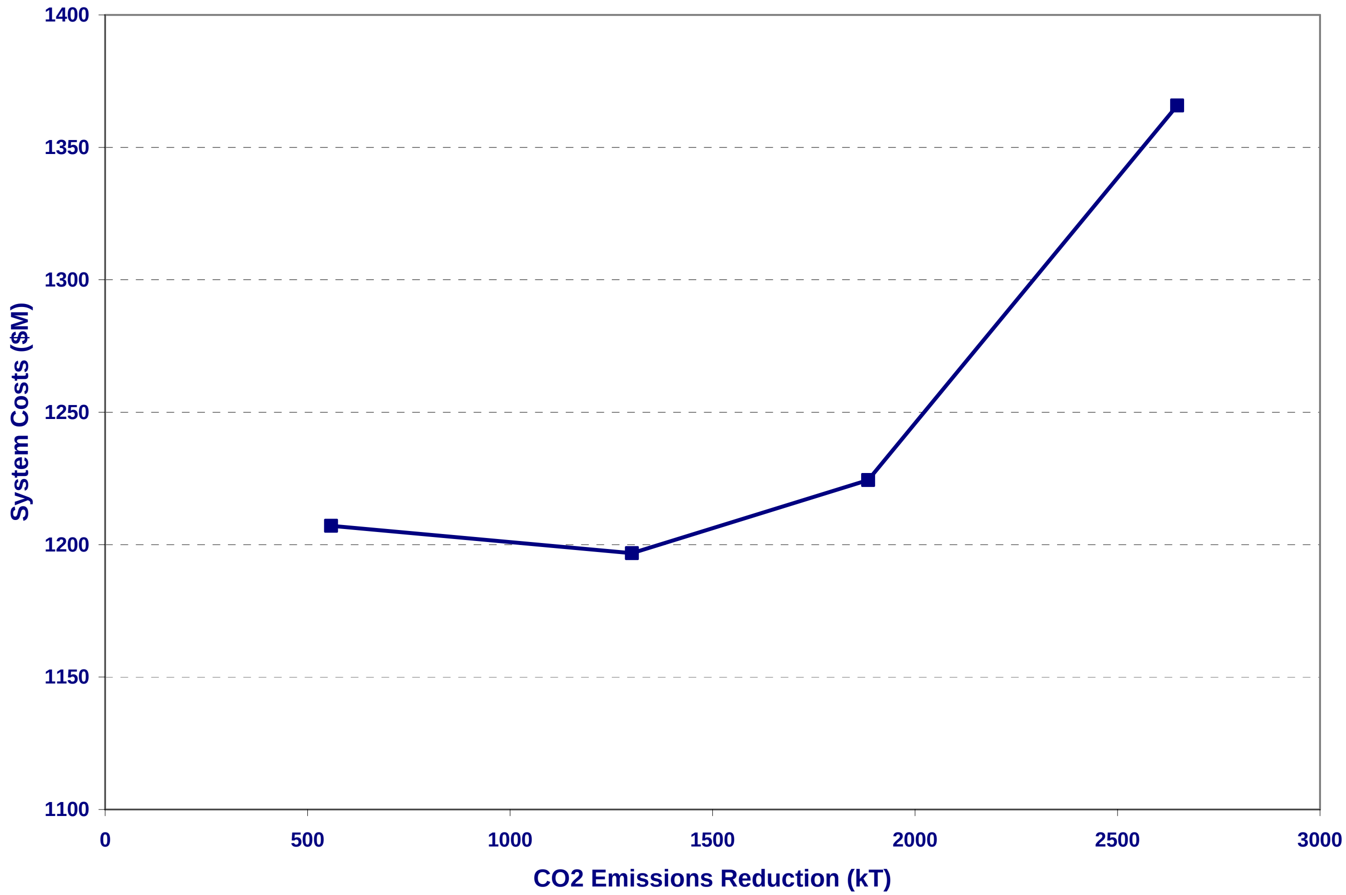


Figure 7-25: Scatter of Wind Power Generation in West Zone

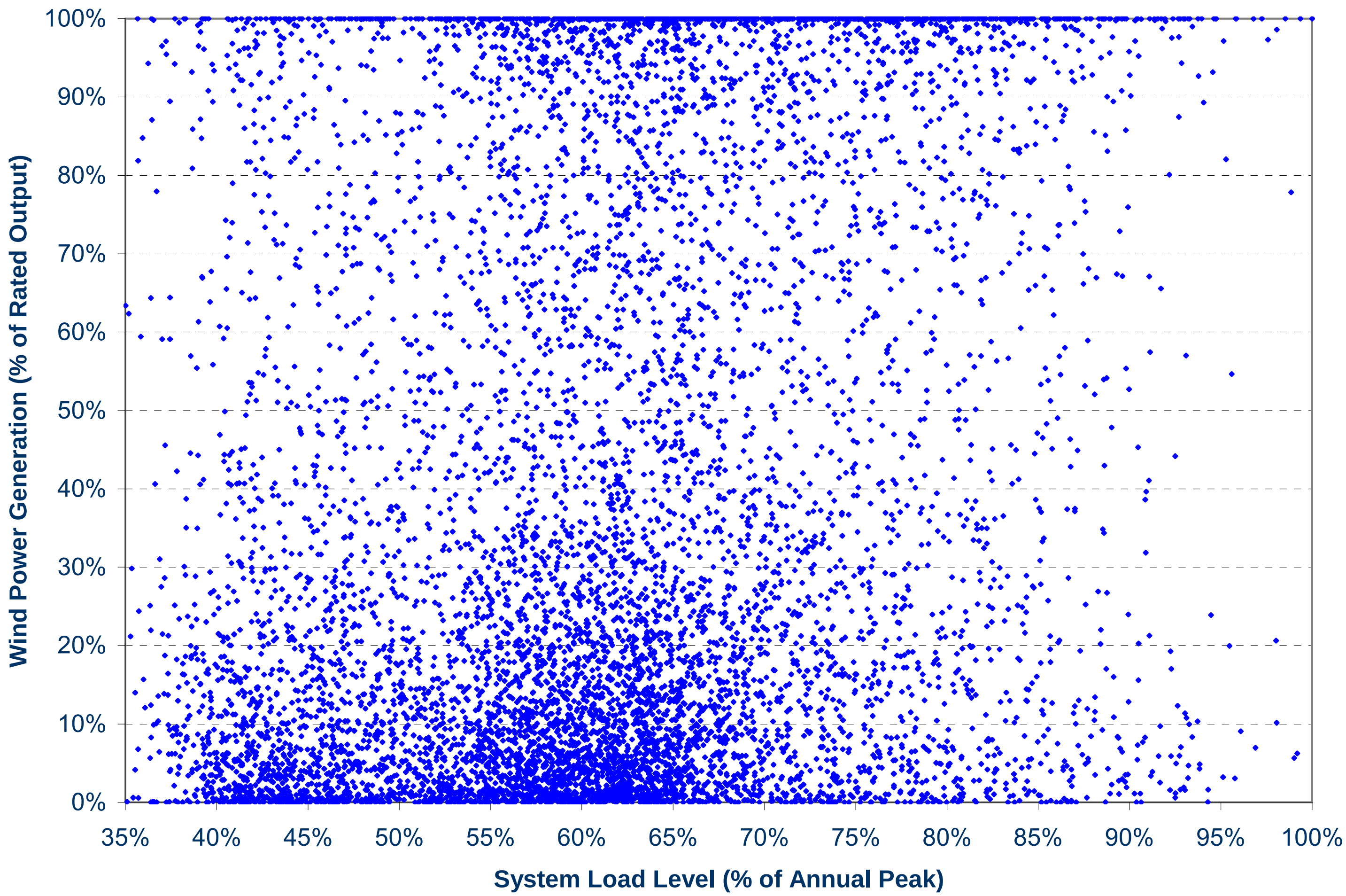


Figure 7-26: Scatter of Wind Power Generation in Six Zones

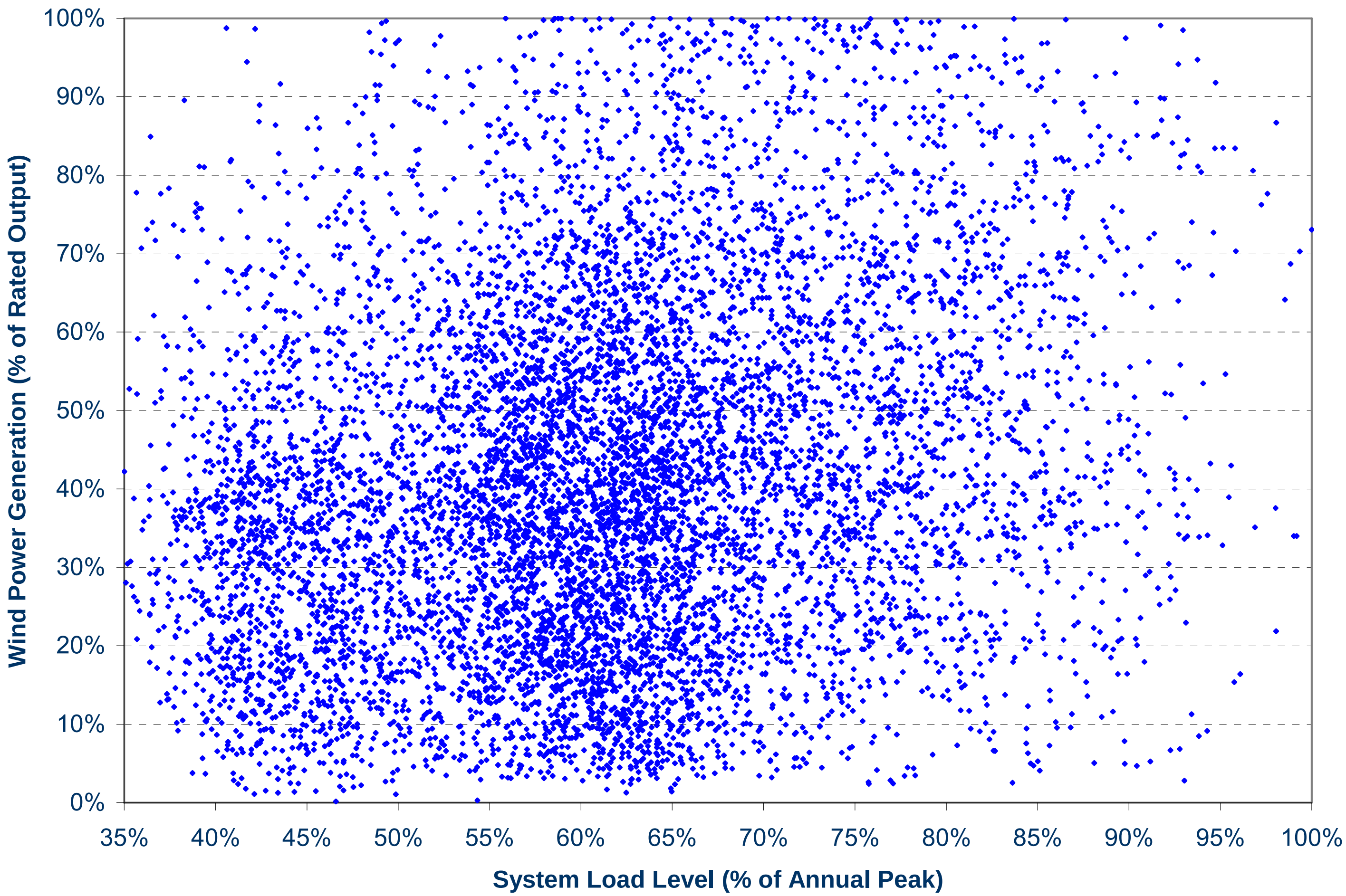


Figure 7-27: Occurrence Frequency of Wind Power Generation in West

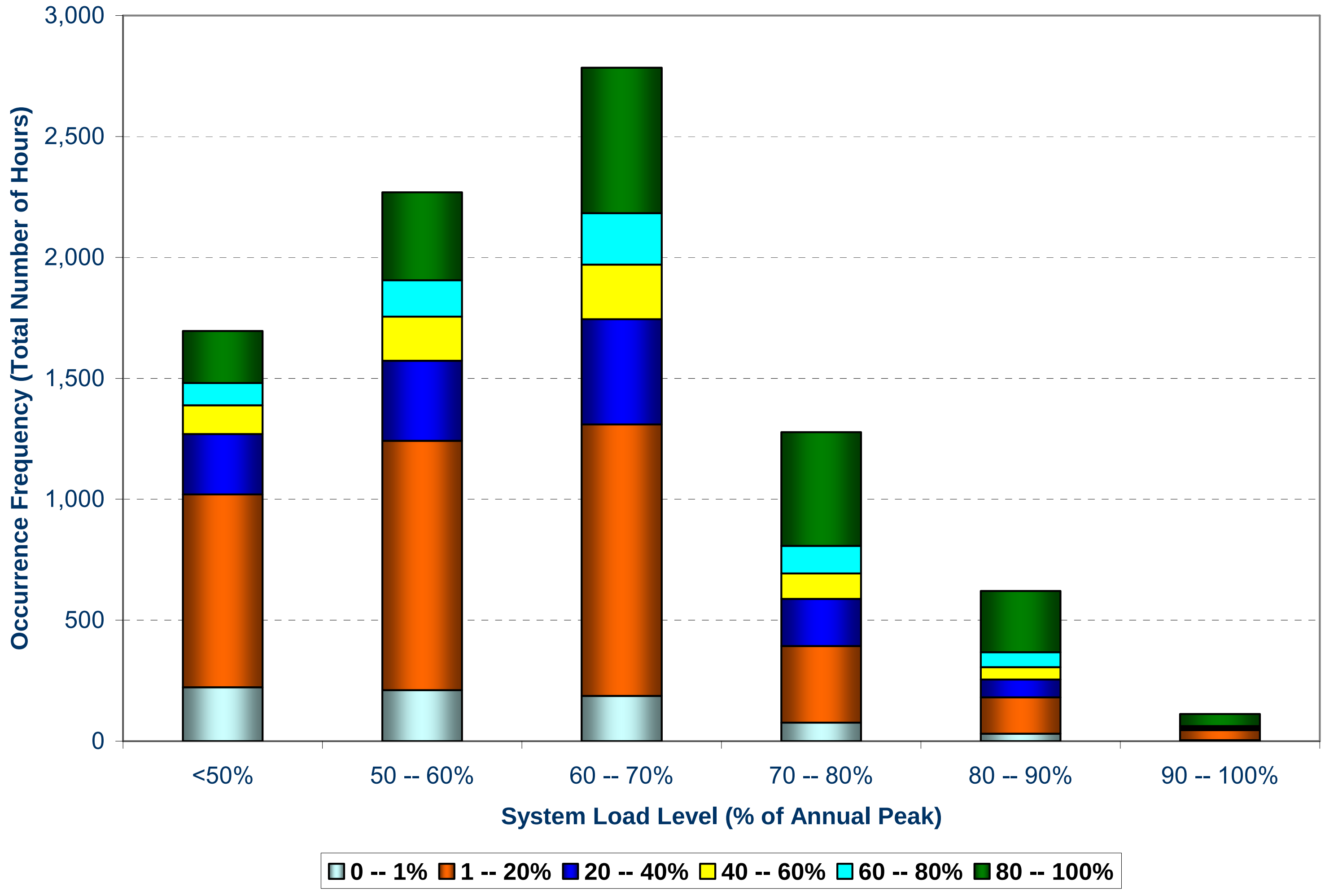


Figure 7-28: Occurrence Frequency of Wind Power Generation in Six Zones

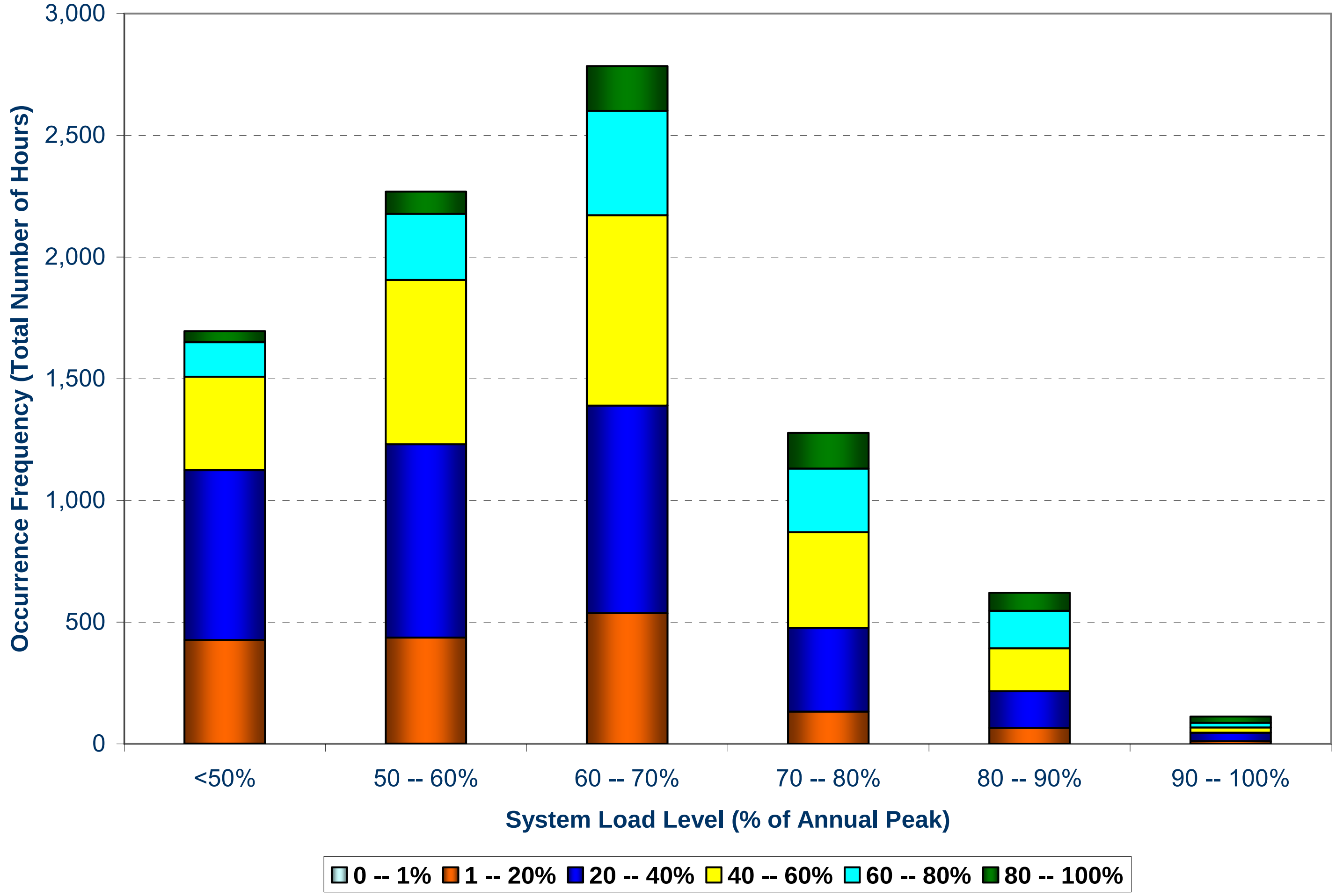


Figure 7-29: Wind Power Generation in West

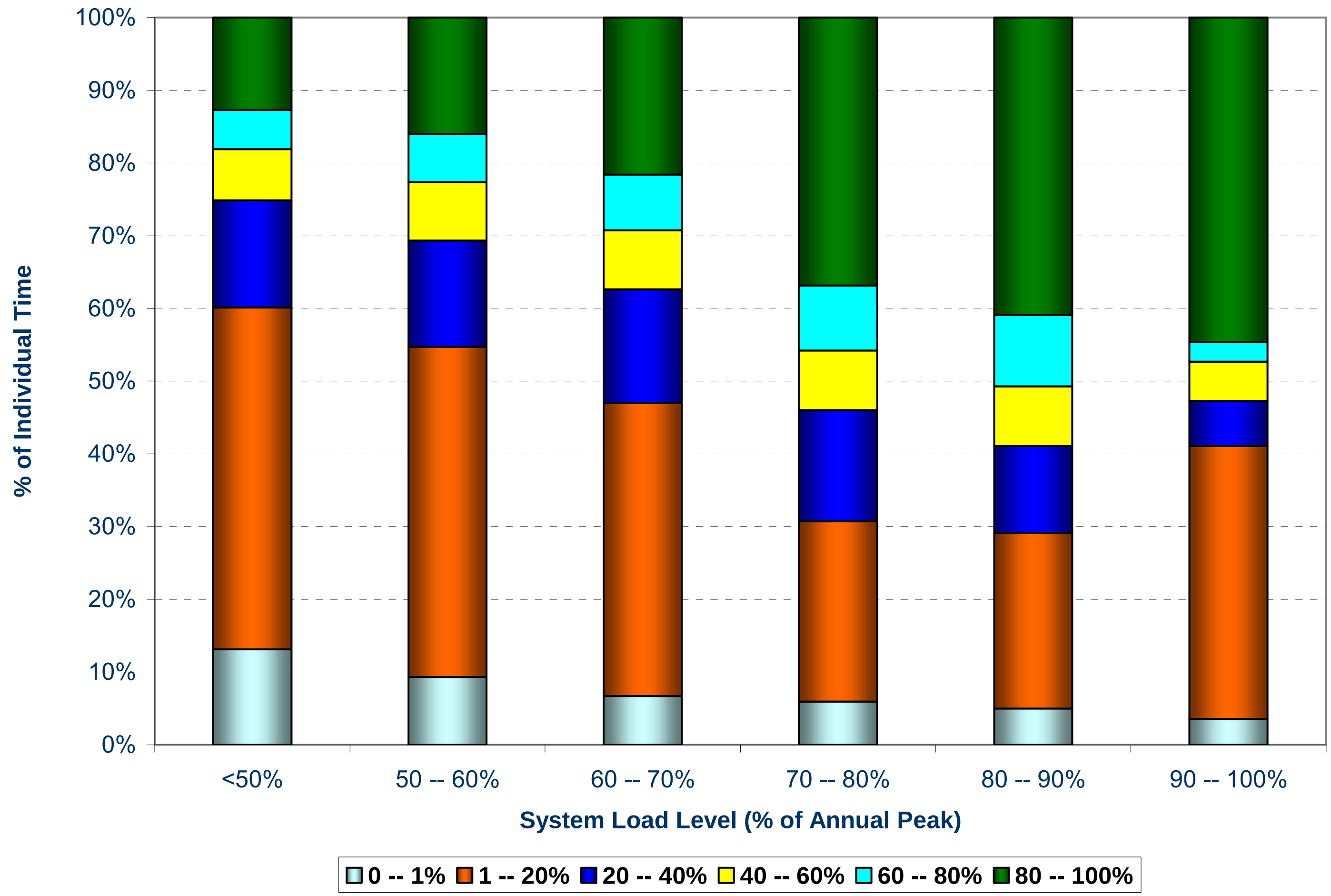


Figure 7-30: Wind Power Generation in Six Zones

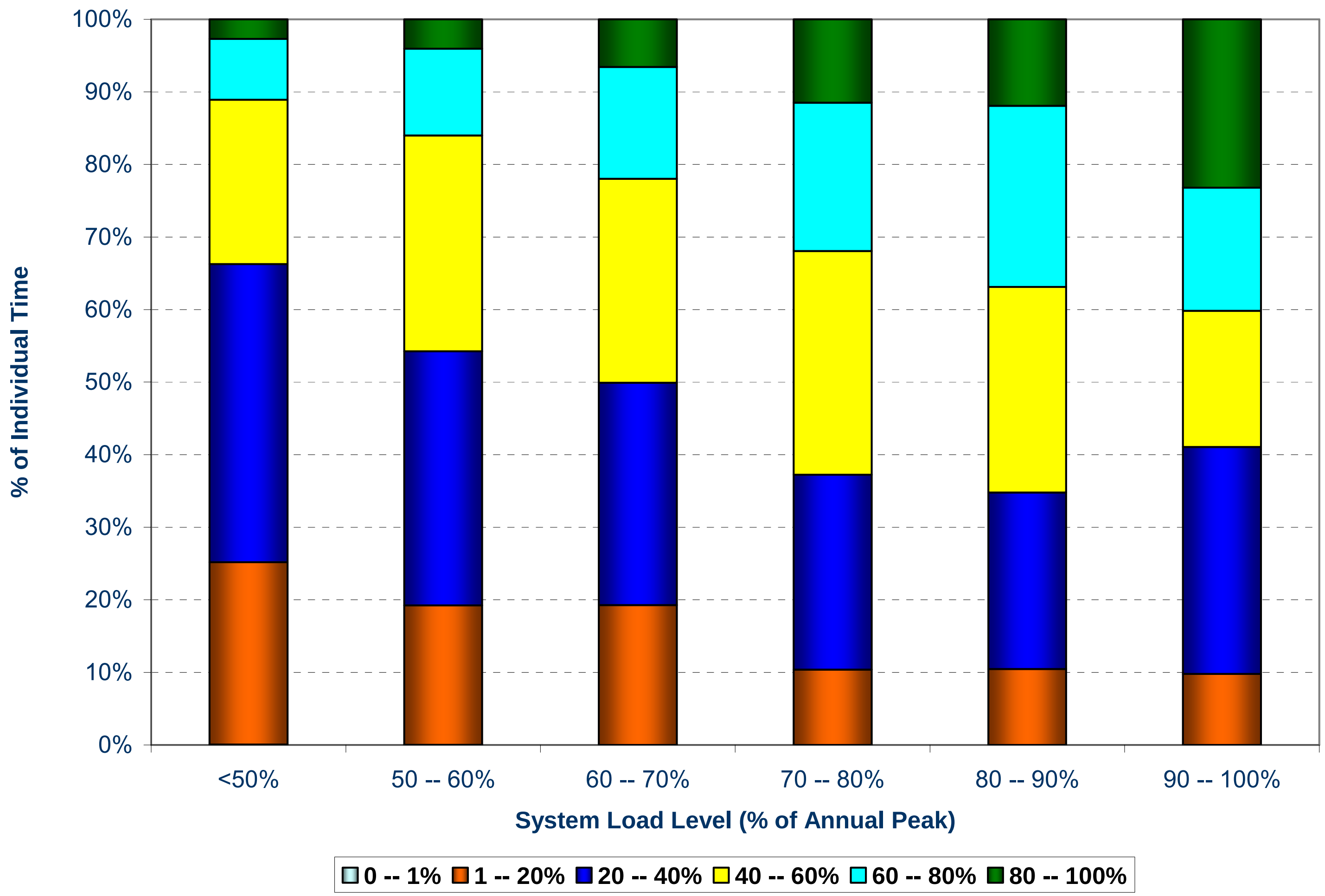


Figure 7-31: Hourly Swing of Wind Power Generation

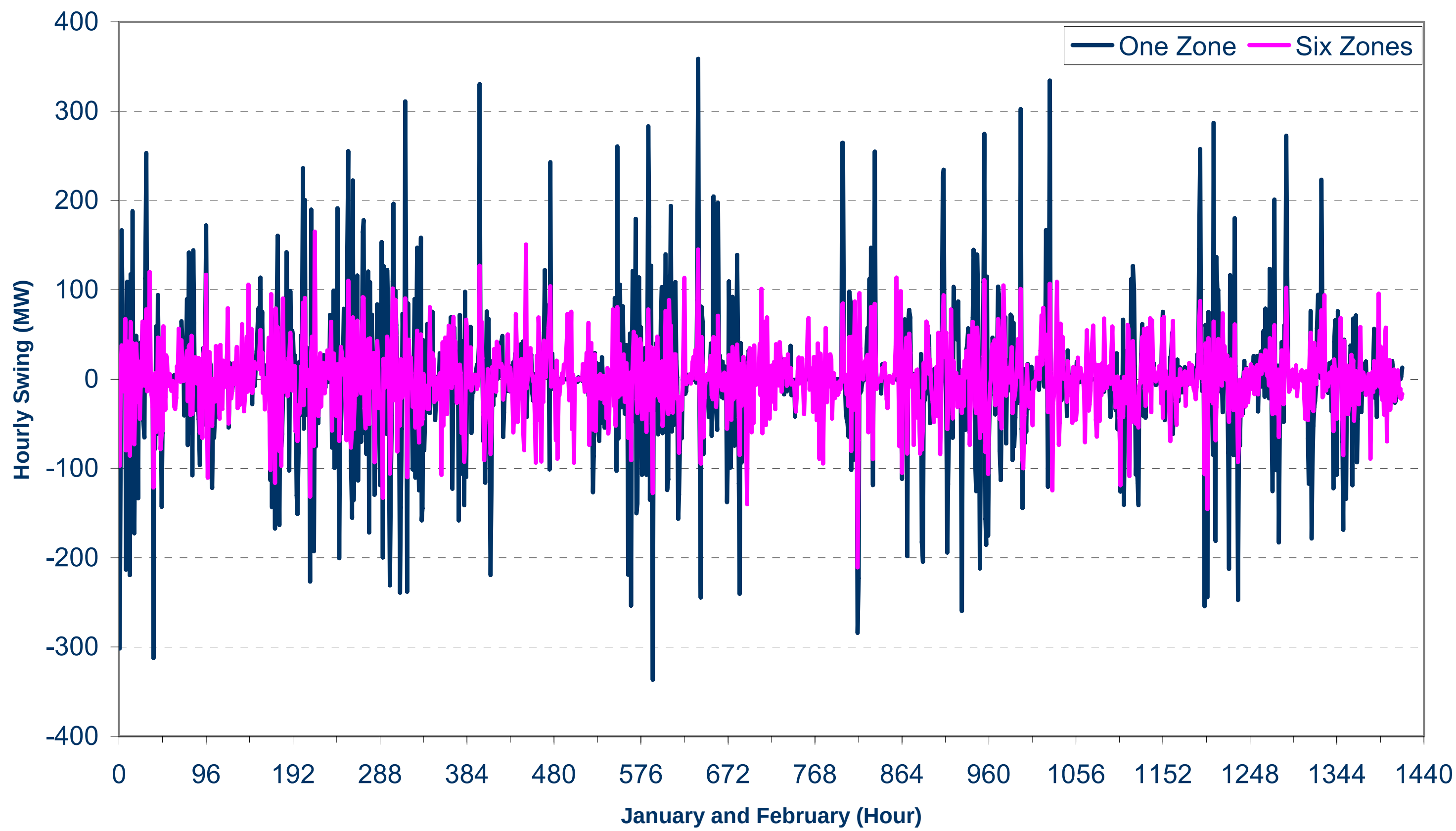


Figure 7-32: Swing Magnitude of Wind Power Generation

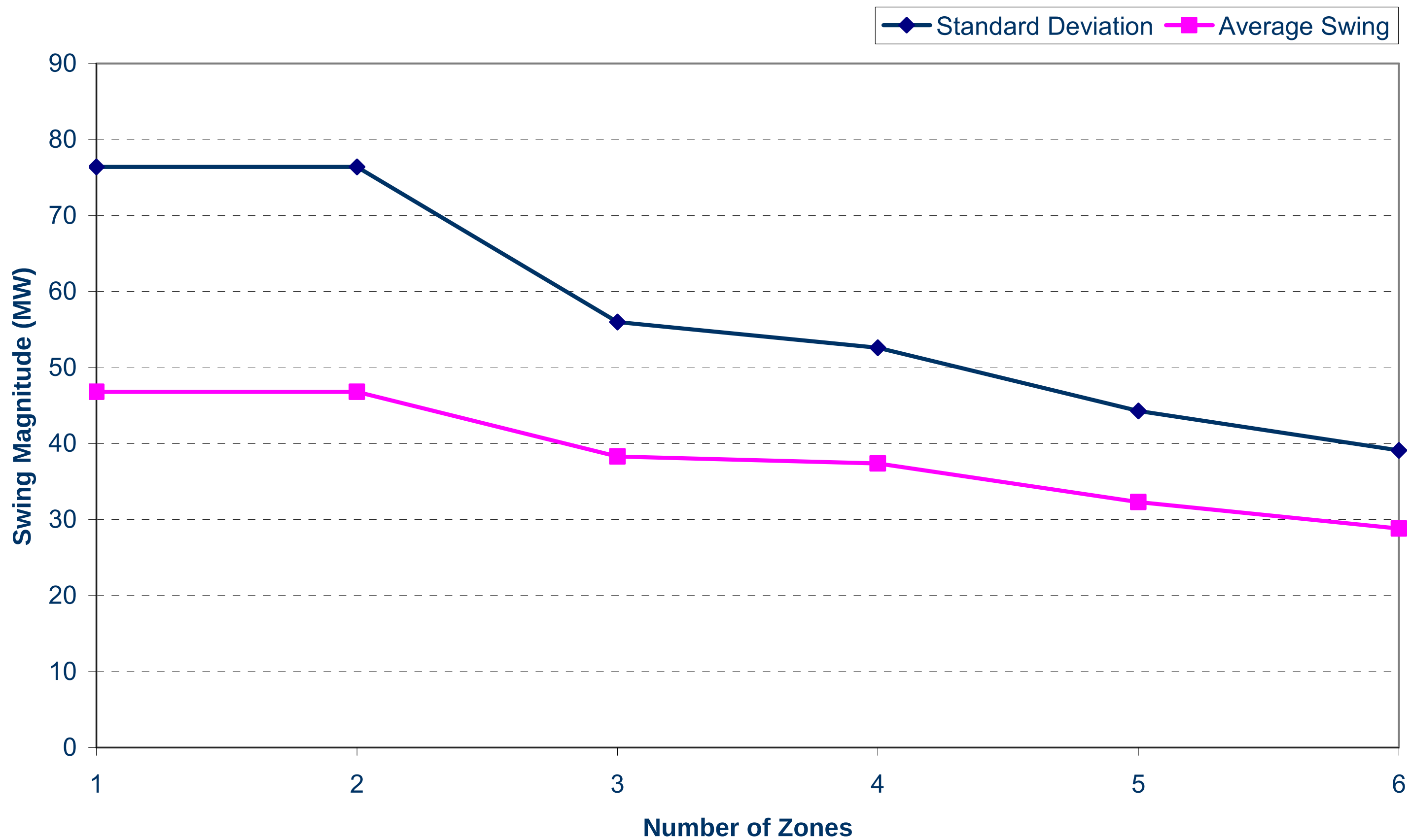


Figure 7-33: System Load in January 28, 2020

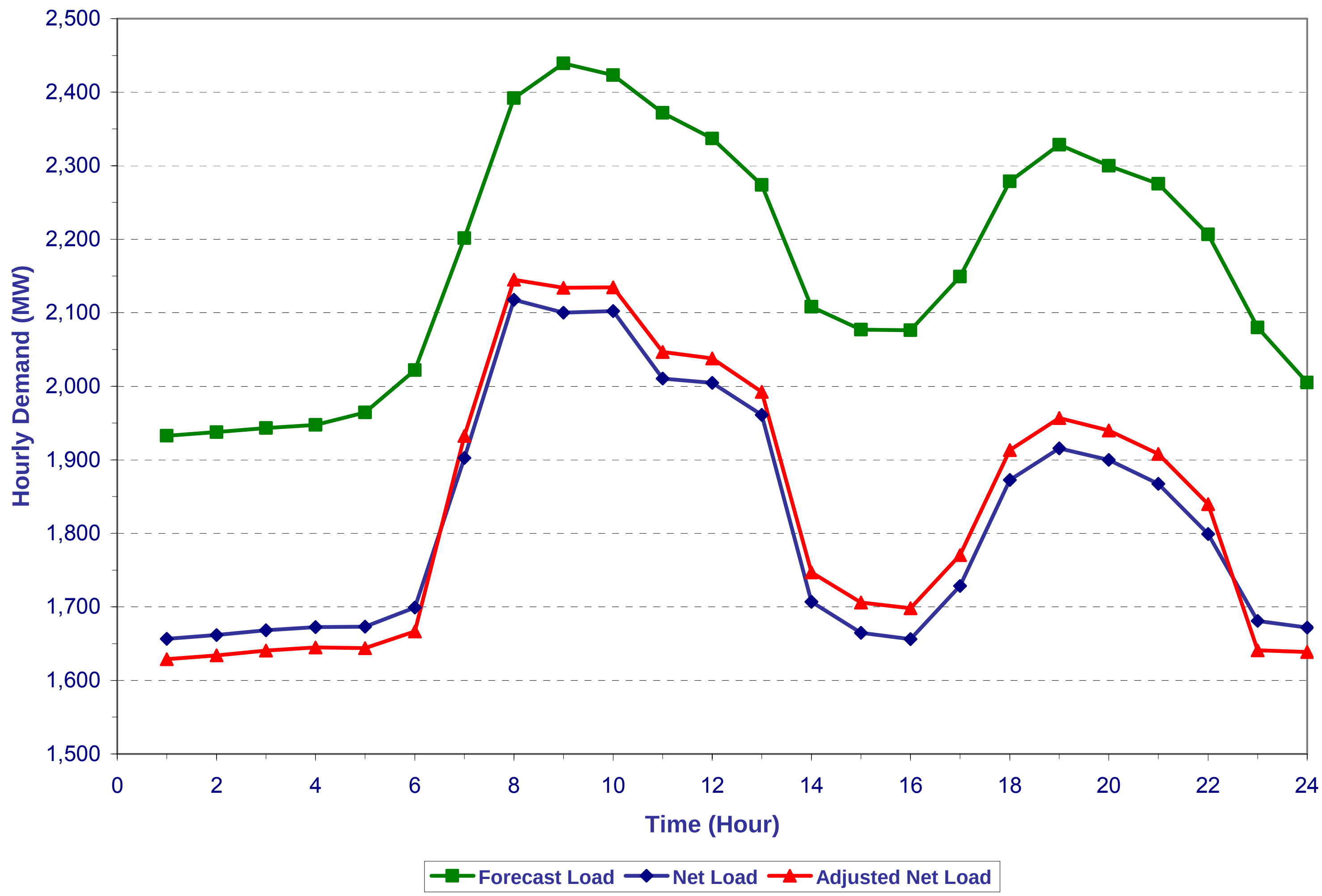
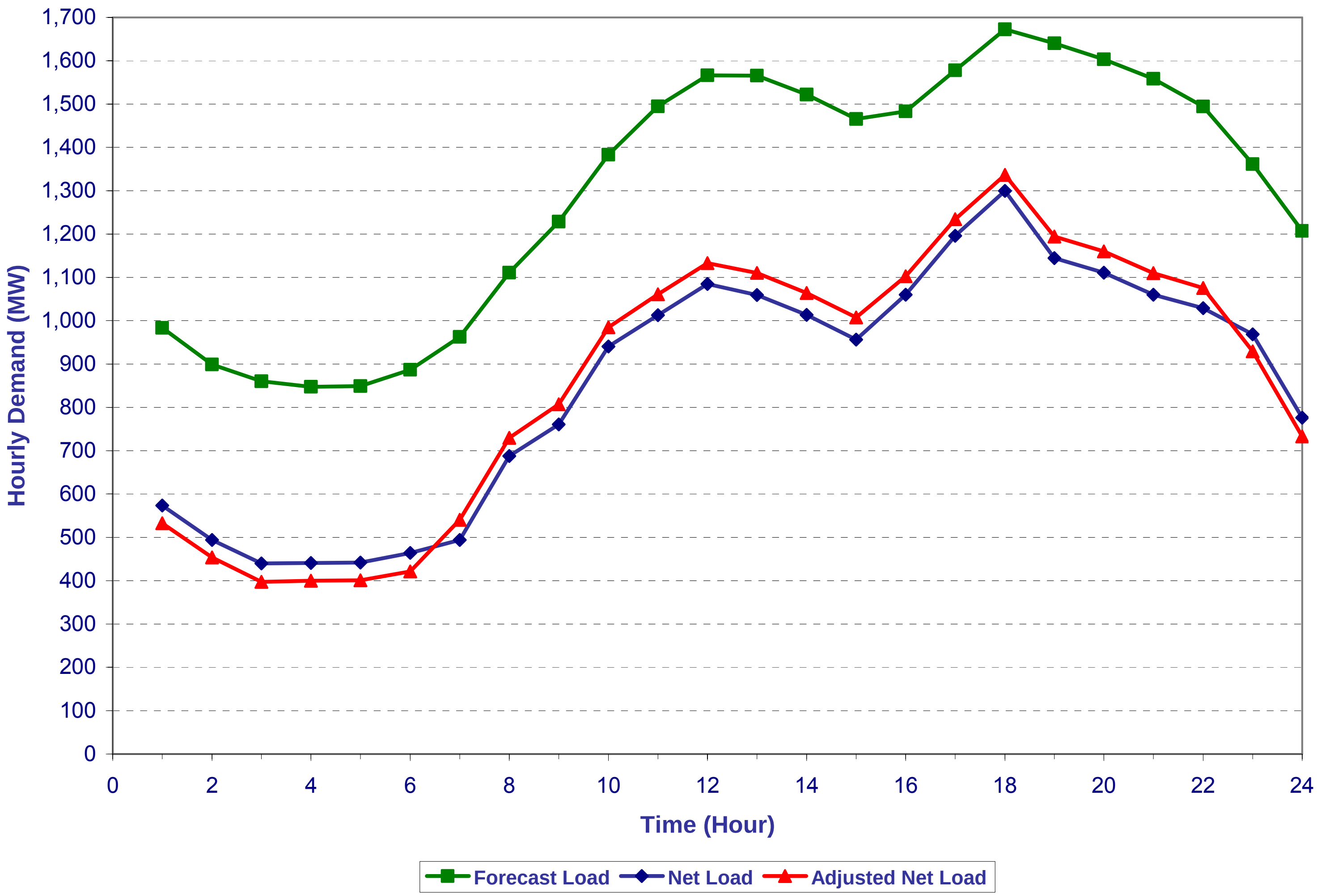


Figure 7-34: System Load in December 26, 2020



8. Conclusions and Recommendations

8.1 Introduction

This section presents the conclusions and recommendations of the study.

8.2 Conclusions

The results of the Nova Scotia Wind Power Integration Study lead to the following general and main conclusions:

(1) The study results presented in this report are based on many important assumptions such as forecast annual peak and energy demands over the study period, typical annual hourly load demand pattern, DSM achievements, interruptible load contribution to system operation, generating unit costs including fuel, O&M and capital, generating unit operational characteristics, forecast water in-flows, existing and new transmission facility characteristics, new transmission reinforcement costs, CO_2 emissions offset costs, forecast zonal wind power output patterns, zonal allocation of wind power capacity and wind energy prices. **Significant changes or fluctuations in one or combinations of these parameters could lead to different conclusions than those reached in this document.**

(2) The forecast interruptible loads for the years 2008, 2010, 2013 and 2020 are 385, 394, 407 and 434 MW respectively. These forecasts are based on the current market situation and policies, incentives and supply reliability to the industrial loads. The industrial customers might change their choices on interruptible tariffs in the future. This should be monitored by NSPI.

(3) The current NSPI peak load forecasts (before accounting for DSM achievements and interruptible loads) for 2008 and 2020 are 2,312 and 2,866 MW respectively. Due to various uncertainties such as economic growth, population growth, electricity tariffs, power industry deregulation, and government policies on environment and other important aspects, the load demands including both peaks and hourly patterns might change significantly from the forecast values. This should also be monitored by NSPI.

(4) The emission caps considered in this study are for the most likely case and the CO_2 offset prices are $15.06 per tonne in 2010 and $38.76 per tonne in 2020. If the actual prices are much higher or lower (especially for year 2020 and onward) than the assumed values, the study conclusions on the overall system costs of the various wind power integration levels could change. The changes in governments' environmental policies in the future would also have impacts on the study conclusions.

(5) One of the most important factors in evaluation of the economic impact of wind power integration is the forecast fuel prices for the thermal units. If the fuel prices, especially for those used by cycling units such as GTs, CCs and CTs, vary significantly from their forecast values the study economic impact results could be quite different.

(6) The magnitudes of requirements for AGC, load following, spinning reserve, 10-minute non-spinning reserve and 30-minute reserve have significant impacts on system costs including capital expenditures and operation costs. If future system operation requires different magnitudes for these various categories of reserves, system costs could be significantly different.

(7) The study results are based on the presumed allocations of new wind power plants to six zones within the province. Creation of sub-zones within each zone and allocation of zonal new wind power generation capacity to these sub-zones would tend to reduce the overall variability of the wind power generation available to the system. Changes in locations of the new wind power plants could have impacts on the system operations and costs as presented in this report.

(8) The assessment of expected wind power generation was based on wind data received from NSPI and several wind power developers. It was found that wind power plants in the Canso Strait and Sydney zones would have the highest annual capacity factor of some 43.6% while the power plants in the Truro and Pictou zones would have the lowest annual capacity factor of some 31.9%.

(9) Wind power integration levels of 311 MW, 581 MW, 781 MW and 981 MW were assessed. It is noted that the maximum output of each wind power integration level is less than its name plate capacity as per the assumptions on availability, losses, and other factors. The amount of wind power capacity is referred to as the name plate capacity unless explicitly specified.

(10) Each of the NSPI steam turbine driven generating units (burning primarily petcoke, coal and HFO) has minimum down and minimum up time requirements and limits on the range in which AGC can be provided which directly affect the dispatch of the generation fleet and the costs of system operation including fuel costs. When technically feasible, modification to reduce such requirements could increase generation system operation flexibility and could potentially reduce system operation costs.

(11) Due to system constraints and unit/plant cycling capability, there could be some periods when the regulation (AGC and load following) service can not be met. This will occur more frequently at higher levels of wind power integration.

(12) The dispatch analysis indicated that transmission corridors between the Sydney and Truro buses would experience more hours operating at their maximum limits than other transmission corridors.

(13) At higher levels of wind power integration, generation from steam turbine driven units would be reduced and replaced by wind, LFO and natural gas generation.

(14) The analysis of the impacts of wind power integration on the transmission system has, at this stage, been carried out without undertaking stability analysis. The steady-state load flow analysis indicated that at the wind power integration level of 581 MW, the transmission system would need investment to replace one circuit breaker at the Trenton substation. The new breaker would be rated at 1,500 Amps.

(15) In the case of an additional 200 MW of wind power (for a system total 781 MW) allocated to the West (100 MW), Valley (50 MW) and Truro (50 MW) zones, the load flow analysis indicated that except for the costs listed in the item above, the transmission system would not need any further major reinforcement.

(16) The load flow analysis indicated that the current transmission system can evacuate additional wind power of no more than some 130 MW from the Canso Strait and Sydney zones. If more wind power capacity is expected to be built in these two zones (as would be the situation for one of the 781 MW of wind power capacity cases studied and both of the 981 MW capacity cases studied), a new transmission circuit would be required. In this

study, it is identified that a new 345 kV transmission line running from the Canso Strait bus to the Metro bus would be required to evacuate more wind power (higher than 130 MW) from the Canso Strait and Sydney zones. It was estimated that the costs of the circuit and its associated substation additions/enhancements would be some $262.2 million.

(17) It is generally true that the system would need more AGC and load following services when a higher level of wind power is integrated. For example, with the existing level of wind power capacity (61 MW) the system would need 16.3 MW of AGC service in 2020 but this would be increased by 21.6 MW, or 132.2% to 37.9 MW when the system has a total of 581 MW of wind power. The system AGC requirement depends on its load pattern, the location and generation pattern of wind power plants.

(18) In the case of 61 MW of wind power generation, the system would need 54.8 MW of 10-minute load following capability in 2020. This requirement would be increased to 91.7 MW when the total wind power is increased to 581 MW. The difference between the two values is 36.8 MW, i.e. an increase of 67.2%.

(19) The analysis results indicate that shifting of the entire wind generation pattern by 24 hours would have very limited impact on the requirements for AGC and 10-minute load following services. However shifting of the wind generation pattern could have significant impacts on system dispatch analysis (unit dispatching capability and system costs).

(20) It can be generally stated that more wind power integration (up to the 981 MW studied) would result in more reduction of air emissions.

(21) The estimated avoided cost of GHG emissions in 2010 would be in the range from some $8.3 to $9.1 million when the system has a total of 311 MW of wind power capacity installed. When the installed wind power capacity is increased to a total of 581 MW by 2013, the estimated avoided cost of GHG emissions in 2013 would be some $28.6 million.

(22) The avoided cost of GHG emissions in 2020 varies from some $21.6 to $102.9 million depending on the wind integration levels and zonal allocation of wind power generation. If the system can only accommodate the total of 581 MW of wind power capacity that is estimated to be needed to meet the RES 2013 requirement, the avoided cost of GHG emissions would be some $50.4 million in 2020.

(23) Either of the two 311 MW wind power integration options would produce at least some 907 GWh of post 2001 renewable energy in 2010 or some 6.8% of annual energy production, which will meet/exceed the RES 2010 requirement. The total renewable energy generation will amount to some 2090 GWh or more, i.e. 15.6% or more of annual energy production. The total system costs for the two 311 MW wind power integration options are very close, some $728 million, which is slightly lower than the $728.9 million estimated for the business as usual case (with only the existing 61 MW of wind power capacity) when the CO_2 offset costs are included.

(24) The system would produce some 1,770 GWh of post 2001 renewable energy or 13.2% of annual energy production in 2013 when it has a total of 581 MW of wind power generation plants. This will increase the total renewable energy to some 2,950 GWh or some 22.1% of annual energy production. When accounting for CO_2 offset costs, the system costs would be some $901.1 million for the 581 MW wind power integration case, which is almost equal to the system costs of $900.7 million for the base case, i.e. only the existing 61 MW of wind power plants.

(25) The integration of 781 MW of wind power into the system in 2020 if technically feasible, would produce at least 2,386 GWh of post 2001 renewable energy or about 18.2% of annual energy production. The total renewable energy would be at least 3,556 GWh or 27.2%. The two 781 MW wind power options would have total system costs ranging from $1,224 to $1,293 million. The higher value includes annualized capital payment of the identified new 345 kV transmission line. These values compare to $1,247 million for the system costs for the base case with the existing 61 MW of wind capacity in the system.

(26) The integration of 981 MW of wind power if technically feasible, would produce at least 3,132 GWh of post 2001 renewable energy in 2020 or about 23.9% of annual energy production. The total renewable energy would amount to 4,278 GWh or 32.7%. With a total of 981 MW of wind power in the system, the system costs would range from $1,366 to $1,374 million. Both of the two values include annualized capital payment of the identified new transmission line. These values compare to $1247 million for the system costs for the base case with the existing 61 MW of wind capacity in the system.

(27) It is generally true that higher prices paid to producers of wind energy would result in higher system total costs.

(28) Concentration of wind power plants would result in higher requirements for AGC and load following services and it could also create more generation dispatch and system security problems.

(29) The results indicate that as wind power capacity installed on the system increases the number of stops and starts of the large thermal units increase significantly. The operating levels of these units also fluctuate more to accommodate variations in wind production and this leads to all components of the delivery system experiencing greater load variations. The studies carried out to date, which have been in accordance with the Terms of Reference for the study, have not been detailed enough to identify the overall impacts of such factors for levels of wind power above 581 MW. Even for the 311 and 581 MW of wind power generation not all the related costs have been captured in the analysis due to data limitations.

8.3 Recommendations

Based on the above conclusions, Hatch's recommendations are presented as follows:

(1) The generation patterns/variations of wind power plants have direct impacts on system AGC service, load following requirement, unit scheduling and real time dispatch. The expected generation patterns of the wind power plants were assessed using the available wind data records for each of the zones. It is recommended that the actual generation patterns of the wind power plants should be compared with these assessed values when the system has some 200 MW or more of wind power capacity. Based on the comparison, the future generation patterns of wind power plants by zone and within zones should be appropriately predicted and the impact of wind power plants on AGC and load following requirements should be assessed based on the new predictions.

(2) The capacity accreditation of wind power plants could be taken into consideration in generation expansion planning or operations planning. After say 200 MW of wind power plants are commissioned and lessons are learned, the capacity credit of wind power plants should be re-evaluated.

(3) Wind power forecasting will have both technical and economical impacts on daily NSPI operation of the system. It is recommended that Nova Scotia launch a wind power

forecasting pilot project when the system has some 200 MW or more of wind power generation. The actual wind power generation and forecast outputs could be compared and valuable experience could be learned from the pilot project.

(4) The Government of Nova Scotia has instituted a DSM program which is expected to achieve an accumulated firm peak load reduction of some 427 MW and annual energy reduction of some 3,097 GWh by 2020. The Government or its agencies should closely monitor the achievements of the DSM program as even relatively small shortfalls in achievement could have significant impacts on system planning and operation.

(5) The zonal 1-minute load profiles for 2005 were selected as the base for construction of zonal load patterns for the study years. It would be desirable to select a different year as the calculation base, compare the results from the two different bases and examine the differential impacts of wind power integration.

(6) Generation unit dispatch analysis carried out in this study was based on perfect forecasts of hourly load demands, hourly wind power generation, water in-flows and availability of generation units. For system daily operation, the most volatile parameter among these listed items is wind power generation. It is recommended to carry out sensitivity analysis to different levels of wind power forecasting error.

(7) The system dispatch results are based on the 2-hour simulation interval. For wind power integration levels at or below 581 MW, this simulation step could provide certain benefits such as significant reduction in computation time without sacrificing the accuracy of results. It is suggested to carry out the dispatch analysis in the step of 1-hour interval for levels of wind power integration above 581 MW.

(8) The study results of transmission analysis are based on load flow analysis. As the dynamic and short circuit characteristics of wind power plants are quite different from the conventional power units/plants, it is recommended to carry out short circuit and stability analysis, identify the dynamic impact of wind power integration on system operation and address the potential problems.

(9) The transmission analysis has identified a need to construct one 345 kV transmission line running from the Canso Strait bus to the Metro bus if significant additional amounts of wind power capacity would be developed in the Canso Strait and Sydney zones. The estimated costs of the new circuit are some $262.2 million. It is suggested to investigate further the possibility of wind power developments in the two zones, compare the costs/benefits of development of wind power plants in the two zones or other zones, and study the associated overall benefits of the new line to the system. It is recommended to carry out a detailed cost estimate of the new line and investigate its costs/benefits further if these suggested analyses show favourable outcomes.

(10) The analysis results indicate that wind power plants would have higher capacity factors during winter season than their annual average values. As the high hourly loads within a day normally occur during day time and evening hours, it is recommended to carry out sensitivity dispatch analysis to the wind power generation pattern by shifting the entire pattern by 6, 12 and 18 hours.

(11) CO_2 offset costs are in the range of $150 to $400 million depending on the study year and the level of wind power integration. These values are based on the CO_2 offset prices assumed, which are $15.06 in 2010, $22.40 in 2013 and $38.76 in 2020 per tonne of CO_2 equivalent. As this factor has very significant impact on system total costs and the

differential system costs resulting from the various levels of wind power integration that were assessed, a review of these assumed prices is recommended as government programs to combat CO_2 emissions are further developed.

(12) Higher levels of wind power integration result in more frequent changes in loading, start-ups and shutdowns of steam turbine driven generating units. Thus these generating units would face more operational challenges as wind power capacity increases. NSPI should carry out technical/economic studies to investigate if any investments on these units are desirable to meet the operational challenges or improve their operational capability.

(13) The study results have illustrated the impacts of concentration of wind power generation and the benefits of diversity of wind power generation. When possible, the future wind power generation in the province should be reasonably diversified.

(14) In order to evaluate the impacts of wind power forecasting error on system day ahead unit scheduling and two hour ahead dispatch day analysis, different market structures would be required, which would establish compensation rules for those generators which are committed as per the day ahead or two hour ahead instructions but are not needed in the real time operation and penalty rules for those which are committed but could not deliver their commitments in the real time operation. The market rules should be reviewed considering these factors.

Appendix A

Terms of Reference

SCHEDULE "A"

Nova Scotia Wind Integration Study
Terms of Reference
June 8th, 2007

1. Background

The Government of Nova Scotia has recognized in its energy policy the contribution that renewable generation can make to the reduction of greenhouse gas and other air emissions in Nova Scotia. The renewable energy standards for Nova Scotia requires that, by 2010, 5% of the total Nova Scotia electricity requirement be supplied by post 2001 renewable energy sources, rising to 10% by 2013. While wind is not the only form of generation eligible to meet this requirement, the renewable requirement is likely to be supplied largely by wind generation.

Nova Scotia Power Inc. (NSPI) provides more than 97% of electric generation, transmission, and distribution to 470,000 customers across Nova Scotia. NSPI owns and operates 5,200 km of transmission and over 25,000 km of distribution circuits.

NSPI is a vertically integrated utility. The Nova Scotia Power System Operator (NSPSO) is the component of NSPI that performs the system operator functions under the terms of the *Open Access Transmission Tariff* (OATT) approved by the Nova Scotia Utility and Review Board (UARB) on May 31, 2005 and the *Electricity Act* and Wholesale Market opening which came into effect on February 1, 2007. Other companion documents included the Wholesale Market Rules, Wholesale Market Regulations, and the Renewable Energy Standards Regulations (RES), which are located on the Department of Energy's website, and the Open Access Transmission Tariff (OATT), which are located on Nova Scotia Power Inc's website.

Wind is a variable generation resource and the output of wind generation facilities at any time is determined by the wind, not by the system demand. As a result, the power system must be capable of adjusting other forms of generation in order to accommodate the variability of the wind generation, on both a technical and economic basis. This adds to the demands placed on other forms of generation. This is not unique to Nova Scotia as many other jurisdictions are coming to grips with the issue.

The technical ability of the Nova Scotia Power system to integrate wind generation and the associated costs were identified as major concerns during recent consultations by the Department of Energy into green attribute administration and the related contractual frameworks. The commissioning of a study to provide some certainty in this area has become a priority. The results of the study should provide a basis for:

- Government policy decisions on current and future levels of the renewable energy standard and on implementation of renewable-to-retail sales;
- Investor assessment of the extent of wind generation opportunities in Nova Scotia;
- Nova Scotia Power System Operator (NSPSO) / Transmission Provider system

impact studies in relation to new investment;

- NSPSO determination of market rules, standards, codes or market procedures necessary to facilitate the integration of wind generation into the system in the most economical manner;
- NSPSO determination of impacts on system adequacy requirements in respect of load following and other ancillary services;
- NSPSO and UARB determination of relevant rates and tariffs;
- The least cost approach to implementing the current Renewable Energy Standard (RES) and setting of future RES targets.

2. Organization of the Study

2.1 Funding

The Nova Scotia Department of Energy will contract for and lead the wind integration study. Funding will be provided by the Province of Nova Scotia.

2.2 Advisory Steering Committee

The results of the study may have a wide range of uses as indicated in section 1. It is, therefore, important that these users have the opportunity before and during the study to identify their needs and to understand and question any assumptions embedded in the study. To this end, the Department of Energy will establish and chair an advisory steering committee which will monitor and review the progress of the study and provide advice to the Department on scope, methodology, assumptions etc. The advisory/steering committee will include representatives from the Department of Energy, and one member from Nova Scotia Power System Operator (NSPSO), Nova Scotia Power Inc. (Generation), Nova Scotia Utility and Review Board (UARB), Consumer Advocate, Municipal Electric Utilities of Nova Scotia Cooperative and the Canadian Wind Energy Association (Can WEA), representing the renewable power producers.

2.3 Study Contributors

The study will depend on contributions from the Nova Scotia Department of Energy, the NSPSO, and developers of potential wind projects in Nova Scotia. In addition the consultant will be expected to secure information from public and/or commercial sources.

The NSPSO will be the primary resource for all load and power system data for the study, including data for the existing wind generators in Nova Scotia and on interconnection applications and associated studies. The NSPSO will be the primary resource to the consultant to describe the system operation and control processes, and to assist in determining operational changes and cost impacts arising from wind generation. The NSPSO will assist in assessing the interaction of wind penetration and the Ancillary Service sharing arrangements with New Brunswick, and will provide the liaison with the New Brunswick System operator in its role as Reliability Coordinator for the region.

The consultant may make specific requests of other stakeholders, and is expected to canvas other stakeholders for relevant contributions. The success of the study depends critically on access to the best available information, some of which is held by developers of actual and potential projects. Confidentiality provisions to protect commercially sensitive information of this type are discussed below.

2.4 Confidentiality

In order to complete an effective study, the consultant will require access to certain data that is confidential. This could include individual wind facility performance data that is not otherwise subject to disclosure or in the public domain. Study contributors will be expected to provide such information subject to individual confidentiality agreements with the consultant. This will likely include NSPSO provision of individual project data as well as project developer's information on prospective projects.

Provision of third party project information by NSPSO is governed by the Generator Interconnection Procedures (GIP) and Standards of Conduct, and therefore any release of Confidential Information pertaining to the interconnection requests (including NSPI's own generation) will be treated in accordance with the Confidentiality provisions of the GIP and GIA. The consultant will be expected to analyze and / or aggregate such confidential data and to include in its report the results of such analysis or aggregation in a manner that respects the confidentiality of the source data.

3. Scope of Work

3.1 Overview

The wind integration study will comprise three phases, with the possibility of limited overlap. Interim reporting at the end of each phase will include a review of the planned scope for subsequent phases in the light of findings to date.

The baseline for all studies is the system status as of end 2006 (with approx 60 MW of wind generation connected). Development scenarios will comprise:

- 2010 RES requirement of 5% (post 2001) new renewable energy, predominantly wind (approx 270 MW connected);
- 2013 RES requirement of 10% (post 2001) new renewable energy, predominantly wind (approx 570 MW connected);
- other intermediate or extreme value to be determined during Phases 1 & 2;
- additional wind generation beyond the RES to 2020 (200 MW);
- review of New Brunswick wind integration study and impacts on Nova Scotia.

Generation embedded in the distribution system or behind load meters can introduce additional issues of concern to the overall reliability of the electric power system. This study should address the feasible limits of embedded generation on the NSPI system.

Some of the analysis will require the recognition of regional or zonal distribution of projects. It is estimated that a total of 5 such regions or zones should provide sufficient granularity to address transmission constraints as well as meteorological diversity.

Other jurisdictions have addressed the issue of wind integration in a number of recent studies. For example, the Alberta Electricity System Operator (AESO) and the Ontario Independent Electricity System operator (IESO) studies are available on their website. The Nova Scotia study should draw on or reference as appropriate the generic information provided in those reports.

The New Brunswick System Operator completed a Maritimes Area Integration Study in August 2005 for the Atlantic Electricity Work Group. The Nova Scotia study requires a review of the New Brunswick study and the possible impacts of the New Brunswick power system operation on the Nova Scotia system**.**

3.2 Phase 1: Data Collection and Analysis

The Phase 1 data collection work will be the basis for the analysis to be undertaken in the study. Data is required in four areas: wind patterns and consequent generation output patterns; generation facility characteristics; Nova Scotia system data; and air emission data with respect to greenhouse gas and air emissions.

Task 1.1: Wind data:

- Wind variability and consequent output variability by region across the province, including recognition of seasonal and diurnal patterns, ramp rate, ramp duration, and frequency. This will comprise precise project-specific or site-specific data as available;
- The precise data records are likely to have limited duration and geographic scope; they will have to be supplemented by information inferred from public or commercially available meteorological records. The target should be to construct data for a minimum of a three year test period, subject to review on the basis of likely cost / benefit;
- Diversity of wind variation by region across the province;
- Predictability of wind and output by region across the province, considering time frames including the Operations planning time-frame (seven days ahead) to the Unit Commitment time-frame (three days ahead) to the Day Ahead Scheduling and Dispatch Day Scheduling (up to 30 minutes before the hour). Historical forecast data is available from those study contributors (including NSPI), which installed production wind generation or wind test towers over the past five years. Other wind data may be extrapolated from Environment Canada;
- Incidence of high-wind-speed cut-out events;
- Incidence of wind speeds between cut-in speed and rated-power cut-out speed;
- Incidence of other cut-out or non-availability events.

Task 1.2: Wind generation facility characteristics:

- Identification of applicable wind generator characteristics which are relevant to impacts on the power system (e.g. voltage flicker, power factor / voltage control, low voltage ride through, harmonics);
- Review of the common wind turbine generator technologies on the market today, and those likely to become commercial in the next ten years (such as induction generator, doubly-fed induction generator, fully-inverted variable-speed machine, and synchronous machine with mechanically damped coupling).

Task 1.3: Greenhouse gas and air emissions data:

- Emission profiles of the generation facilities whose operation would be impacted by increasing wind generation in the province (both positive and negative impacts);
- Work undertaken to date by NSPI to establish costs of alternative emission reduction strategies (as a basis for Nova Scotia avoided cost calculations).

Task 1.4: Power system operational characteristics, constraints, and requirements.

The Nova Scotia power system may offer unique challenges to high penetration levels of wind generation. There is a single interconnection point to other power systems, with a capacity of less than 15% of peak load. With a single 345 kV line between NS and NB and a single 345 kV line in Maine, the probability of the Maritimes and/or NS to become an electrical island for a single contingency must be considered. The consultant will meet with NSPSO to explore the system conditions and characteristics that will frame the Phase 2 Assessment of Impacts, and Phase 3, Mitigation Measures and Costs.

The characteristics of potential interest include (but are not limited to):

- System load data and seasonal/diurnal load shape;
- System adequacy standards and requirements (planning reserve and operating reserve);
- Tie control requirements (NERC Control performance Standards);
- Regulation, load following and energy balancing requirements;
- Power ramp rate for generators providing regulation and Automatic Generation Control;
- Transmission Open Access Tariff and Generation Interconnection Procedures
- Market Operating Procedures as per Market Rules (unit and tie-line scheduling, curtailment procedures, etc.);
- Hydro-thermal optimal dispatch and unit commitment procedures;
- Water management considerations for hydroelectric procedures;
- Internal transmission constraint, transient stability issues, dynamic reactive power reserves, oscillation damping;
- Special protection Systems in use in NS and NB;
- Voltage flicker concerns on remote sub-transmission lines;
- Transmission protection standards including automatic restoration and re-closing;
- Black-start system restoration procedures;
- Under frequency load-shedding program;
- Islanded operation, frequency control;
- Embedded generation considerations (distribution or behind the load meter).

3.3 Phase 2: Assessment of Impacts

The first two tasks in Phase 2 will define the development models for each scenario, and define the reliability criteria that will have to be satisfied under each scenario.

Task 2.1: System Model Development

- Test years will match key RES milestones: 2010, 2013 and 2020;
- Planned transmission and committed generation additions will be included in models;
- Load levels;

- Transmission and generation contingencies to test low voltage ride-through, wind generation stability and damping;
- Stressed transmission interfaces that limit new generation interconnection;
- Establish generic project (size and location) to meet RES milestones with minimal transmission interconnection requirements.

Task 2.2: Definition of relevant reliability criteria

- Applicable reliability criteria to be tested;
- Assumptions with respect to NB tie line operation and reserve service sharing protocols (NSPSO will have the lead in this determination, in consultation with consultant and NBSO);
- Test conditions for modeling (eg load ramping and rest-of-system status: to include low load condition, high ramp condition, and high load condition);
- Voltage regulation / power factor requirements;
- System stability and other relevant security requirements.

The analytical work in Phase 2 will seek to quantify the adequacy and efficiency impacts under each scenario and assess the materiality of security-related concerns in the context of expected project size within the Nova Scotia system.

Task 2.3: Preliminary assessment of "capacity accreditation" which is the extent to which wind developments contribute to fulfillment of system adequacy requirement, based on dependability of wind and coincidence with peak loads in each season (this is not intended to be a full "loss of load probability" analysis). This will provide a basis for determining the net capacity requirement of other resources.

Task 2.4: Quantification of impact on regulation /AGC, load following and operating reserve ancillary service requirements.

Task 2.5: Quantification of impact on unit commitment and water allocation decision making for system balancing.

Task 2.6: Assessment of interaction with intra-province transmission congestion.

Task 2.7: Quantification of impact on tie-line utilization and energy transactions.

Task 2.8: Assessment of potential impacts on system security

Task 2.9: Quantification of impact on greenhouse gas and air emissions.

Task 2.10: Identification and assessment of sensitivity of impacts to project size / concentration and location.

Task 2.11: Assessment of the adequacy of the FERC ORDER 661 Low Voltage Ride-Through curve for multiple wind generator sites.

3.4 Phase 3: Mitigation Measures and Costs

The study will focus on physical impacts and requirements, and on total cost impacts. Where appropriate the study should include recommendations of particular mitigation measures.

The study will not seek to define particular responsibilities other than between the NSPSO / Transmission Provider and generators, and will not seek to recommend specific cost allocation or market rule changes.

It is expected that the NSPSO will provide information on specific incremental and average costs of ancillary services consistent with those approved by the UARB in the context of tariffs and rates, or based on the present NSPI integrated planning work. The consultant should use such data in estimating the costs of the impacts identified in
Phase 2.

Task 3.1: Assess cost impact of the adequacy impacts as identified in tasks 2.3 to 2.6. Include recommendations of measures necessary to mitigate such costs.

Task 3.2: Make recommendations of the measures necessary to mitigate security concerns identified in task 3.3 as material.

Task 3.3: Quantification of costs of re-dispatch and day ahead scheduling.

Task 3.3: Identify the key barriers to integration of further increases of wind resources into the Nova Scotia system, and any possible means to overcome these, including but not limited to: transmission reinforcement, emerging technologies, wind generator design and control characteristics, energy storage technologies, market structure, new generation with load following capabilities and wind forecasting requirements.

Task 3.4: Estimate the avoided cost of alternative means to achieve equivalent greenhouse gas and air emission reductions using specific NS data provided by NSPI and/or other generic industry data.

Task 3.5: Assessment of the impact on a wind project business case / financing with curtailment as a regular operating occurrence.

Task 3.6: Quantification of system costs and GHG impacts as incremental wind generation is added to the system.

Task 3.7: Consolidate findings in a graph showing system cost versus installed wind capacity and GHG reductions versus installed wind capacity.

4. Deliverables

The consultant's key deliverables comprise:

- Work plan developed for kick-off meeting and updated as a tool to assist in coordination of necessary inputs and work tasks;
- Interim report 1, covering Phase 1 work. Note that interim reports will be issued as a basis for review and discussion; they are not intended for update following such discussion. Interim reports will be targeted for the Advisory Steering Committee's review of progress, findings and ongoing work plan, and should be formatted accordingly;
- Interim report 2, covering Phase 2 work;
- Graphical presentation of system reliability, system costs (including capital and

operating) and GHG reduction impacts as incremental wind generation is added to the Nova Scotia electrical system (included in final report);

- The impact of incremental wind energy additions on Nova Scotia Power's ability and costs to meet it's RES obligation and going beyond the RES;
- Draft final report (consolidating all phases of the work);
- Final report;
- Power Point presentations corresponding to draft final and final reports;
- Presentations at stakeholder consultations including reference materials;
- Media information packages highlighting key findings for public dissemination and use.

5. Timing and Budget

5.1 Timetable

The following timetable is proposed. Consultants are invited as part of their proposal to confirm or suggest changes. Item 9, Preliminary findings, refers to the impact of incremental wind on system reliability, system costs, GHG reductions and on Nova Scotia Power's costs and ability to meet it's RES obligation and going beyond the RES. Preliminary result are required by late September, 2007.

Item	Description	Responsible	Date
1	Consultant identification and ToR	DoE with ASC input	June 11th, 12007
3	Issue RFP	DoE	June 15th, 2007
4	Submit Proposals	Consultants	June 29th, 2007
5	Award & contract	DoE / Consultant	July 9th, 2007
6	Kick-off meeting & work plan	Consultant	July 20th, 2007
7	Phase 1 interim report	Consultant	Aug. 31st, 2007
8	Phase 2 interim report	Consultant	Sept 21st, 2007
9	Preliminary findings	Consultant	Sept 21st, 2007
11	Draft final report	Consultant	Oct 31st, 2007
12	Review	DoE / ASC	Nov 16th, 2007
13	Final report	Consultant	Nov 30th, 2007

The ASC realizes that the time line for the study is very tight and invites consultants to address all time line issues and concerns in their proposals. The ASC is prepared to accept changes to the time line and modifications to study tasks which have minimum impact of the primary objectives in order to minimize the study time line.

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