March 8, 2011

Hon. Brad Duguid
Minister of Energy
Hearst Block
900 Bay Street, 4th Floor
Toronto, ON M7A 2E1

Subject: Ontario Electrical Grid and Project Requirements for Nuclear Plants

Dear Minister Duguid,

Enclosed please find the report you asked the Ontario Society of Professional Engineers (OSPE) to prepare at our meeting at your office on September 1, 2010. The report titled "*Ontario Electrical Grid and Project Requirements for Nuclear Plants*" summarizes a number of technical and project requirements that OSPE believes should be considered for inclusion in the procurement specifications for any new or refurbished nuclear units.

The second report that you requested at that meeting, regarding the professional engineering community's views of Ontario's Long Term Energy Plan, is being prepared and will be forwarded to you later.

The enclosed report was issued for comment in December 2010 to key nuclear industry stakeholders and OSPE members. For your information, a list of individuals who submitted comments is contained in the Acknowledgement section at the end of the main body of the report.

The enclosed report was produced by OSPE's Energy Task Force and endorsed by OSPE's Board of Directors. We welcome any additional comments or questions your staff may have. We are also pleased to make our Energy Task Force members available to you should your staff wish to organize a meeting of affected stakeholders to share views and answer any questions they may have.

Thank you for considering the views of the professional engineering community. Professional engineers are directly involved in designing, constructing, operating and maintaining our province's energy infrastructure. We hope our recommendations are helpful to your planners in creating a more reliable, safer, environmentally responsible electrical energy system that also provides a competitive advantage to Ontario businesses.

Yours truly,

John Schindler, M. Sc., P. Eng.
President and Chair
Ontario Society of Professional Engineers

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cc: Hugh MacDiarmid, President and CEO, Atomic Energy of Canada Ltd.
cc: Denise Carpenter, President and CEO, Canadian Nuclear Association
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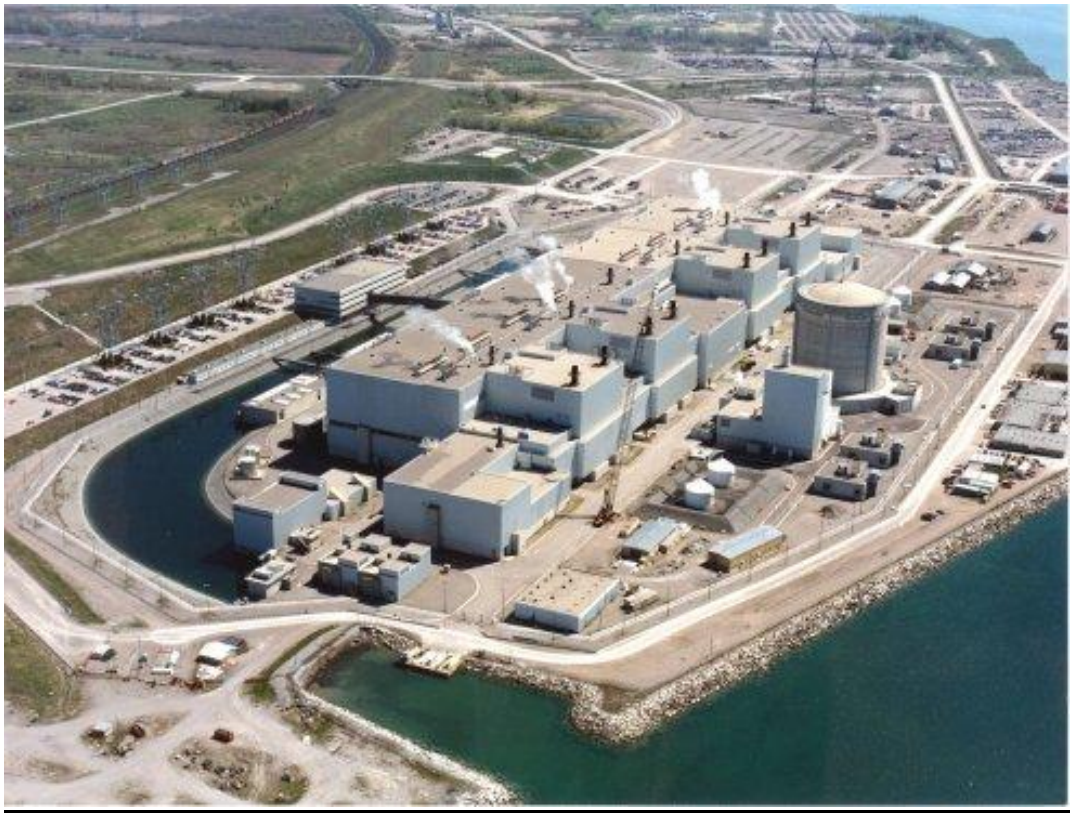
ONTARIO SOCIETY OF PROFESSIONAL ENGINEERS

Ontario Electrical Grid and Project Requirements for Nuclear Plants

Issued March 8, 2011



Darlington Nuclear Generation Station – photo courtesy of Ontario Power Generation

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Executive Summary

The recent specifications for 2 new nuclear units for the Darlington site did not include a number of important requirements of the Ontario Electrical Grid. This document has been produced at the request of The Honourable Brad Duguid, Minister of Energy, at a meeting with OSPE representatives on September 1, 2010. Its purpose is to provide energy planning decision-makers a list of requirements they should consider for inclusion in the procurement specifications of nuclear plants to ensure electrical power reliability and costs remain a competitive advantage to Ontario industries.

The safe, reliable and environmentally responsible operation of the Ontario electrical grid requires that nuclear units have a number of capabilities that are not universally provided by nuclear vendors unless they are called for in the specifications. The Bruce B and Darlington stations were designed with a number of engineering features to allow Ontario's electrical grid to operate reliably with more than 20% of its energy coming from nuclear generating stations. These features are not common in the USA or many other jurisdictions in the world where nuclear energy is less than 20% of electrical energy supply.

Any new Ontario nuclear units will take several years to build and then run for up to another 60 years. Nuclear plants are difficult and expensive to modify. Consequently, the current and any anticipated future requirements for the safe, reliable and environmentally responsible operation of the electrical grid should be included in the specifications for any new nuclear units. Because of Ontario's heavy reliance on nuclear power (55% of energy supply in 2009) it is not practical to follow the USA practice of shutting down nuclear plants during grid disturbances and blackouts.

This document identifies a number of technical requirements that were included in the specifications for the current CANDU nuclear plants in Ontario and that are required to ensure nuclear plants do not shut down during grid disturbances, load rejections or grid blackouts. It also identifies a number of additional requirements that could be used to:

- manage excess base load generation and avoid distorting wholesale market prices,
- accommodate growing amounts of intermittent wind and solar generation,
- reduce the annual greenhouse gas emissions from electrical generation,
- reduce the blackout duration following a widespread grid collapse,
- reduce restoration time following a widespread grid blackout,
- ensure frequency and voltage performance and grid reliability are maintained when additional nuclear capacity is added,
- minimize the impact on the grid of any equipment failures at a nuclear unit, and
- minimize the capital cost of new nuclear generation,

An assessment of these requirements to determine which are needed by the electrical grid should be undertaken and the essential items should be included in the specifications for new nuclear units. Also back-fitting of these requirements into the existing CANDU units when they are refurbished should also be considered.

ONTARIO SOCIETY OF PROFESSIONAL ENGINEERS

Ontario Electrical Grid and Project Requirements for Nuclear Plants

Contrary to popular belief, the electrical generators of nuclear plants can follow the load demands of the electrical grid provided specific engineered systems to permit this mode of operation are included in the plant design. Nuclear unit electrical power maneuvering has a number of advantages over other methods to manage reduced grid load during the evening and on weekends. This capability should be considered for inclusion in the specifications for nuclear units.

A robust steam bypass system rated for continuous operation in parallel with turbine/generator operation can be used to manage surplus base generation and back up intermittent wind and solar generation. This can be done at a very low fuel cost of about 0.5 cents per kWh and with zero greenhouse gas emissions. A robust steam bypass system can permit daily electrical load cycling and maneuvering with no wear and tear on the nuclear systems. In addition, the periods of negative electrical market prices could be eliminated because it would not be necessary to bid negative energy prices into the market to preferentially keep nuclear units on-line. A robust steam bypass capability rated for continuous operation should be considered for inclusion in the specifications for nuclear units.

The August 2003 blackout demonstrated that the current hydraulic and fossil plants are not sufficiently large or fast enough to quickly restore the grid to normal operation. Nuclear reactors are large and most are designed with fast speed governors and fast voltage control equipment. They should be considered for use much earlier in the grid restoration process following a grid blackout to better stabilize the grid during restoration and to reduce the time to restore normal grid operating conditions. The engineered systems to accomplish this should be considered for inclusion in the refurbishment programs of existing nuclear units and in the specifications of any new nuclear units.

Due to Ontario's heavy dependency on nuclear energy it is important that the nuclear fleet does not shut down following a grid disturbance or blackout. The Bruce B and Darlington stations have engineered systems that allow the reactors to continue operating during a grid disturbance and following a load rejection or a grid blackout. This capability should be considered for inclusion in the specifications for all nuclear units.

The extended time to return to normal operation following the August 2003 blackout demonstrated that certain automation changes are needed. These changes are needed to assist the grid operators and nuclear plant operators to more effectively control frequency and restore normal operations in a more timely manner. These automation requirements should be considered for inclusion in the specifications for nuclear units.

The unit size, number of units, fuel type, site location and functional independence between the new nuclear units should be reviewed in more detail to determine the optimal requirements to ensure acceptable grid reliability and reasonable cost of power. For example, there is a large imbalance between generation east of Toronto and load west of Pickering. This leaves the province at risk of losing an unacceptably large amount of generation in the event the 500 kV transmission corridor along Hwy 407 is disabled by storms or aircraft accidents. Efforts to reduce this imbalance should continue to receive high priority.

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Ontario Electrical Grid and Project Requirements for Nuclear Plants

1. Introduction

The specifications for 2 new nuclear units for the Darlington site did not include a number of important requirements of the Ontario Electrical Grid. This document has been produced at the request of The Honourable Brad Duguid, Minister of Energy, at a meeting with OSPE representatives on September 1, 2010. Its purpose is to provide energy planning decision-makers a list of requirements they should consider for inclusion in the procurement specifications of nuclear plants to ensure electrical power reliability and costs remain a competitive advantage to Ontario industries.

This document contains technical terms that may not be familiar to the reader. An appendix is provided that explains these and some of the characteristics of the electrical grid and CANDU nuclear units that will be helpful in understanding the discussion in the body of this document.

The safe, reliable and environmentally responsible operation of the Ontario electrical grid requires that nuclear units have a number of capabilities that are not universally provided by nuclear vendors unless they are called for in the specifications. The Bruce B and Darlington stations were designed with a number of engineering features to allow Ontario's electrical grid to operate reliably with more than 20% of its energy coming from nuclear generating stations. These features are not common in the USA or many other jurisdictions in the world where nuclear energy is less than 20% of electrical energy supply. In Ontario 55% of our electrical energy comes from nuclear power and with the retirement of the coal fired stations, and significant new intermittent wind and solar generation, additional capability will be required of our nuclear plants to maintain grid reliability and improve environmental performance.

There is a prevailing belief in North America that nuclear plants cannot maneuver their electrical output and are therefore only useful as base load facilities. **This is simply not true.** The reason most North American reactors cannot load maneuver is that they do not have the required engineered systems to do so.

Nuclear reactors in Ontario are not currently load maneuvered for several reasons:

- Some units do not have the equipment to permit load cycling or maneuvering,
- Older units are experiencing equipment aging factors (eg: pressure tube creep) which reduce operating margins needed for maneuvering,
- Power up-ratings have reduced operating margins required for maneuvering. Several of Ontario's CANDU units have been power up-rated since their original in-service dates,
- Owners are concerned about equipment wear and tear on the nuclear systems when the reactor power is maneuvered frequently, and
- Load-cycling or load maneuvering reduces the total energy output and revenue.

Although there are legitimate reasons why the reactor should operate at constant power, there are no fundamental technical reasons why the generator in a nuclear unit cannot load maneuver provided there is a place for the excess steam, that is produced by the reactor, to go. A robust steam bypass system rated for continuous duty can absorb the required steam load to allow the reactor to operate at full power and the generator to be operated at any lower power. A nuclear

unit can in fact have its electrical output varied to follow the daily load profile of the grid and serve as both a base load and peak load facility provided a robust steam bypass system is available. With a robust steam bypass system, the wear and tear on nuclear equipment would be eliminated because the reactor would operate near its optimal design conditions. The operator would also benefit from an easier monitoring task. Monitoring the turbine/generator and steam bypass system with no reactor power change during electrical load maneuvering is inherently a much easier operating task than monitoring reactor flux spatial distribution and all other plant system parameters during a reactor power change.

During the August 2003 blackout, 3 Bruce B units and 1 Darlington unit ran at 60% reactor full power and at 0% grid electrical power. They were able to do so for hours, because they had steam bypass systems that were designed to de-couple the reactor output from the generator electrical output. Unfortunately, these reactors were provided with a relatively inexpensive steam bypass to the turbine condenser rated for intermittent use at low turbine/generator power. At the time they were designed, a more robust steam bypass system rated for continuous duty at high turbine/generator power was not considered necessary. The existing turbine condenser steam bypass system is not designed to operate with both the turbine and the steam bypass at significant loads for extended periods of time due to excessive erosion damage to the turbine condenser components. However, a robust steam bypass system rated for continuous duty can allow a CANDU nuclear unit to continue to operate at 100% reactor power while the generator can operate at any load below 100%. These robust steam bypass systems can allow generator load maneuvering on a continuous basis at rates limited only by the turbine generator rotor and blade stresses. These rates are higher, for lower temperature nuclear plant steam turbines (typically 5% to 10% per minute), than for fossil fired high temperature steam turbines (typically 2% to 5% per minute) that are presently used for load maneuvering.

In the past, the System Control Center, and more recently the Independent Electricity System Operator (IESO), have tended to play a more reactive role and accepted what the generating stations were willing to provide in functional capability. Generating stations were also allowed to let their grid related capabilities deteriorate and the IESO accommodated them. For example the Bruce A units lost their ability to survive a load rejection and grid blackout several years after they were in-service. During the recent planning process to refurbish the plant, that capability was not restored. Similarly, the Bruce B and Darlington units have lost much of their flexibility to load follow in the evenings and weekends due to various factors. The refurbishment of these units in the future will provide an opportunity to restore their load cycling and even provide load maneuvering capability.

As the electrical grid operating environment becomes more challenging, especially with larger amounts of intermittent wind and solar generation being added, the IESO needs to play a more proactive role in establishing functional requirements for all generation types and ensuring those capabilities are maintained. That functionality should not only be the minimum required to just get by now but should include sufficient operational margin to meet future needs so that prolonged outages do not occur in the future. Grid operators need to be able to rely on sufficient functionality from each of the generation resources so that they have a high probability of performing their duties successfully under all credible scenarios. Nuclear units take several years to build, will operate for up to another 60 years and are costly to modify. Consequently it is

important to also predict future grid requirements based on the future configuration of the grid and incorporate them into the procurement specifications when the nuclear unit is purchased or refurbished.

Currently, the IESO has specific responsibilities to ensure the reliable integration of new facilities, including new nuclear facilities, into Ontario's power system. In exercising this responsibility, the IESO's planning and operating areas routinely provide independent and expert analysis, impact assessments and grid requirements to ensure future adequacy and reliability. These areas include reviewing factors such as unit maneuvering and flexibility, unit size and location on the grid, and contribution to system stability and restoration. Unfortunately, the IESO does not have nuclear experts on staff and therefore must rely on others to identify new technical features that are compatible with nuclear power plants that would improve grid performance.

The IESO administers a robust grid connection process with the province's transmitters. The connection requirements are outlined in the electrical Market Rules and related documents. The performance of the resulting system is then reported to the North American Electric Reliability Corporation (NERC) and Northeast Power Co-ordinating Council (NPCC) to ensure compliance with industry standards. It is important to understand however, that the NERC and NPCC standards are primarily aimed at ensuring each electrical system that is interconnected to neighbouring systems contributes its fair share to the stability, reliability and performance of the interconnected grid.

There is considerable latitude in those industry standards for individual system operators and planners to make supply mix and generation performance choices that can significantly affect that system's response to grid disturbances and subsequent restoration performance. For example, it was no accident that Ontario was one of the first jurisdictions to recover from the grid blackout in the late 1960's but was one of the last jurisdictions to recover from the August 2003 grid blackout. That deterioration in relative performance was the result of choices and decisions made over the intervening 30 year period related to the supply mix and performance capabilities of the various generating units.

The IESO does not currently identify grid requirements explicitly for nuclear generating stations. This is probably a result of precedence. The former Ontario Hydro (now Ontario Power Generation - OPG) generation planning engineers in the 1960's through to the late 1970's included the grid requirements in each nuclear plant's Project Requirements and within each of the plant's System Design Requirements. Consequently, there was no need to explicitly document them in the documentation set at the System Control Center (now the IESO). The current IESO Market Rules do include a number of requirements for the generator excitation and turbine governor systems that all large generating units in Ontario, and in fact North America, should meet. Therefore, for completeness, those Market Rules should also be included in the specifications for any new nuclear units.

Historically in Ontario, the nuclear plant project requirements for each successive nuclear plant became more stringent as the fraction of nuclear generation increased and experience with operating nuclear plants evolved. The Pickering A and B stations were designed to operate through grid disturbances and were also designed to operate for 30 minutes disconnected from the

grid so they could reconnect quickly following a load rejection or grid blackout. Unfortunately operating experience has shown that 30 minutes is not sufficient time for the nuclear operator to ensure plant process and safety systems are operating normally before reconnecting to the grid and for the grid operator to establish grid conditions suitable for the nuclear unit to reconnect. Therefore, Pickering units are currently required to shut down following a load rejection or grid blackout. During the planning for the refurbishment of 2 Pickering A units several years ago, the capability to survive a load rejection or grid blackout was not included in the scope of refurbishment work.

The Bruce A and B stations were designed to operate through grid disturbances and were also designed to operate for at least 6 hours disconnected from the grid so they could reconnect following a load rejection or grid blackout. Unfortunately, a design decision to use booster rods to control reactor power in the Bruce A units rather than absorber rods proved to be a reactor safety concern. They were subsequently removed without installing absorber rods. Consequently, the Bruce A units can no longer operate after a load rejection or grid blackout and are currently required to shut down following those events. During the planning for the refurbishment of the Bruce A units, the capability to survive a load rejection or grid blackout was not included in the scope of the refurbishment work.

When Darlington was being planned in the mid 1970's the need for daily load cycling at certain times of the year was anticipated by the time the first Darlington unit was originally scheduled to be in-service 10 years later. The Darlington station was designed to:

- operate through grid disturbances,
- operate for at least 6 hours disconnected from the grid so it could reconnect following a load rejection or grid blackout, and
- follow a single daily load cycle between 100% and 60% full power without using its turbine condenser steam bypass system. The intent was to design the reactor with sufficient operational margins to load cycle along with the generator so that steam bypass would not be required. As a result, the lower cost steam bypass to the turbine condenser that was used on the Bruce A and B units, was considered acceptable for Darlington because of infrequent use.

Unfortunately, Darlington's current operating license does not allow it to operate as a daily load cycling plant. OPG has not made a licensing submission to the Canadian Nuclear Safety Commission (CNSC) to permit load cycling of the Darlington reactor. The CNSC does not prohibit load cycling or maneuvering, however, OPG would be required to make a safety case in a licensing submission for this capability. It is unlikely OPG will do this because there does not appear to be sufficient operating margins available to permit daily load cycling or maneuvering of the reactor power. In the absence of sufficient operating margins, Darlington could load cycle its electrical output if it had a separate robust steam bypass system. In fact all the existing CANDU nuclear units could load cycle if they had a separate robust steam bypass system that conserved their condensed demineralized water. Essentially this would be a steam bypass system with a closed steam/condensate loop. The size of the steam bypass system can be matched to the amount of load cycling or load maneuvering that would be required.

It is important, that the specifications for Ontario's new and refurbished nuclear plants, that will be in-service for 30 to 60 years have the required capability to meet the present and future requirements of the Ontario electrical grid.

2. Technical Requirements

2.1. Grid Operating Considerations

During the mid 1980's to the mid 1990's, the former Ontario Hydro (now IESO and Ontario Power Authority - OPA) planning studies indicated that additional improvements would be needed to existing and future nuclear plants to manage excess or surplus base load generation (SBG) and to avoid excessively long restoration times following a grid blackout. The initial results indicated that a more robust steam bypass system could be used to manage excess base load generation. These studies also indicated that improvements to the overall plant control system at nuclear units and early participation by nuclear units in the restoration of the grid would be necessary to achieve more reasonable restoration times of 4 hrs typically with an 8 hour maximum period in the winter. These studies also identified that energizing the 500 kV transmission system from either the Bruce or Darlington sites and picking up Toronto load early in the restoration process was a key step in the faster restoration process. The restructuring of Ontario Hydro and opening of the competitive market for electricity in the late 1990's brought these studies and some engineering changes that were planned for the existing nuclear plants to an end. The August 2003 blackout experience re-enforces the importance of completing these planning studies and establishing the necessary performance requirements for the nuclear units.

In 2009, approximately 34% of Ontario's installed generating capacity was CANDU (pressurized heavy water, natural uranium) nuclear units. These nuclear units produced approximately 55% of Ontario's electrical energy. The 2010 Long Term Energy Plan for Ontario targets 12,000 MW nuclear generating capacity or about 53% of energy supply by 2030. Presently some load cycling capability is needed to avoid surplus base load generation and the negative wholesale market electricity prices that result from constrained generation that cannot load cycle. In the future, with a much larger fraction of variable wind and solar generation, additional daily load cycling and load maneuvering will be needed.

Because Ontario relies so heavily on nuclear units for its electricity, the IESO cannot follow the USA practice to simply allow nuclear units to shutdown for a few days during abnormal grid conditions. Ontario does not have sufficient generation reserve and interconnection capacity to neighboring utilities to replace its nuclear generation. When a CANDU nuclear reactor shuts down, it takes approximately 2 days before it can be restarted and up to another day to reach full power operation.

Following the August 2003 blackout, parts of Toronto were without power for about 1 day and full industrial and commercial activities did not resume in the province for several days due to lack of generation. There are also safety concerns with a significant percentage of the population living in high-rise buildings and in dense urban areas. It is important to remember that 4 Bruce A and 1 of the 2 Pickering A reactors were not operating during the August 2003 blackout. These units do not have the ability to operate after a load rejection or grid blackout. Consequently, had

these units been operating, the restoration would have been more difficult and likely longer. Had the blackout occurred in the coldest winter months, the event would have been more serious due to potential for frozen pipes. Based on previous experience with blackouts during the winter, there is also increased risk of house fires and carbon monoxide poisoning due to people's misguided use of inappropriate heat sources to keep warm.

Consequently, extended blackouts should be avoided and specific targets should be established by IESO for acceptable blackout duration under various contingency scenarios and during various weather conditions. Blackout restoration procedures and processes can then be analyzed and the specific required technical capabilities of new and existing nuclear units can be determined.

This document suggests a number of additional electrical grid requirements for nuclear generating units for consideration by the Minister of Energy, IESO, OPA and Nuclear Plant Owners. The new requirements are based on experience gained at the former Ontario Hydro during earlier system planning studies, during development of blackout restoration plans, during grid disturbances and during localized and widespread grid blackouts over the past 40 years. The list is being provided not to circumvent the IESO analysis mentioned above but to stimulate thought about the potential functionality that should be considered in those studies.

It is recognized that imposing additional requirements on existing nuclear plants would be more costly than doing so on new plants. This document endeavors to identify the requirements that should be considered for all nuclear units in Ontario if the planning capacity for nuclear generation continues to be larger than 20% of generation resources. Consideration should be given to back-fitting some of the additional requirements into the existing nuclear plants during their refurbishment programs. For example some modest changes to the overall unit control system and a modestly sized (10%) separate steam bypass system can significantly improve the overall grid performance during normal operation and during grid disturbances. A more generously sized (up to 40%) separate steam bypass system would likely be required at existing CANDU units to provide sufficient grid restoration support following a future widespread grid blackout such as the one in August 2003.

With the retirement of the coal fired units, the planned addition of material amounts (approximately 10,000 MW by 2030) of wind and solar capacity that is variable and the increasing demands by the public to reduce greenhouse gas emissions, means that additional capabilities for our nuclear plants should be pursued. This will also prevent the extended blackout and extended period to restore normal operations to all customer loads that occurred in August 2003 in Ontario.

2.2. Capabilities of Existing CANDU Units

The grid requirements for existing nuclear units at Bruce B and Darlington should be included in the specifications for any new nuclear units. These include:

1. Grid requirements to ensure continued operation during normal grid conditions

- Requirements for voltage control. These requirements can be obtained from the IESO Market Rules (MDP_RUL_0002, Appendix 4) and Darlington generator excitation system design requirements.
- Requirements for frequency control. These requirements can be obtained from the IESO Market Rules and the Darlington or Bruce B turbine governor system design requirements.
- Requirements for dynamic stability. These requirements can be obtained from the IESO Market Rules and the Darlington or Bruce B electrical power output system design requirements.

2. Grid requirements to ensure continued operation during abnormal grid conditions

- The requirement to successfully continue operating through the expected grid frequency and voltage excursions and their duration during abnormal grid conditions. These requirements can be obtained from the Darlington or Bruce B system design requirements for various electrical power supplies and various process systems and from the standard motor specifications.
- The requirement to successfully clear electrical faults on the electrical power output system including transmission system without damage to unit electrical equipment. These requirements can be obtained from the IESO Market Rules and the Darlington or Bruce B electrical power output system design requirements.
- The requirement to avoid a reactor poison outage and reconnect to the grid for at least 6 hours following a load rejection or grid blackout from 100% reactor power. This also implies a successful fast transfer of the station service buses from the system service transformer to the unit service transformer following a load rejection or grid blackout. The 6 hour period may need to be adjusted following a detailed review of the blackout restoration procedures and processes. These requirements can be obtained from the Darlington or Bruce B project requirements, station service design requirements and the steam bypass system design requirements.

2.3. Improved Steam Bypass System

Managing variable wind and solar generation is becoming more challenging as the capacity of these sources increase.

One method is simply not to accept variable wind and solar generation when the grid cannot accept it. This unfortunately would run afoul of government policy and the public's desire to utilize greenhouse gas-free sources of generation whenever it is available.

In an ideal world, variable wind and solar generation would be stored, typically in hydraulic reservoirs. The hydraulic plants would then return that energy during peak periods of the day when customers need it rather than when nature provides it. Unfortunately, Ontario has relatively little hydraulic storage and Quebec has been unable to offer its storage capacity at affordable prices.

Hydraulic units are used directly to compensate for variable wind and solar by reducing power and spilling at dams when wind and solar is producing. Unfortunately the total amount of maneuverable hydraulic capability is limited and insufficient to meet both customer load variation and wind and solar variability.

Gas fired units are also used to compensate for variable wind and solar output. Unfortunately, gas fired units contribute to greenhouse gas emissions and the total amount of maneuverable capability is insufficient to meet both customer load variation and wind and solar variability.

In January 2011, the Ontario electrical system ran out of maneuverable gas fired and hydraulic generation. The wholesale market price of electricity went negative for short periods of time during the low customer demand hours even though January is a relatively high demand month. When prices go negative, our utility neighbours are happy to help out and get paid to take our excess power. Unfortunately this raises electricity bills for Ontario residents. With additional wind and solar coming onto the grid in the next several years, additional maneuverable generation capability needs to be found in order to avoid shutting down low cost nuclear units.

Using nuclear units to compensate for variable wind and solar by reducing electrical output when wind and solar are producing is technically feasible. There is sufficient nuclear generating capacity to provide about 4,800 MW of load maneuvering at a cost and up to 12,000 MW at higher cost.

Unfortunately for various reasons mentioned earlier in this document, most existing CANDU units in Ontario cannot maneuver reactor power. To change electrical power without changing reactor power requires a robust steam bypass capability that is able to operate continuously in parallel with the turbine. The steam bypass system would handle the difference between reactor and turbine/generator power. There are various types of steam bypass systems available, each with different advantages and disadvantages. These are described in more detail in the appendix.

The Bruce A & B and Darlington units were provided with a main steam bypass to the turbine condenser with approximately 60% reactor full power capacity. This system injects steam into the condenser at superheated conditions. Consequently, it is designed for infrequent use due to the high wear and tear that results. This type of steam bypass system is relatively inexpensive but cannot be used in parallel with the turbine operating at higher power levels.

For new reactors, a more robust de-superheated steam bypass system to the turbine condenser similar to those available on some fossil-fired plants could be considered. These bypass systems are typically rated as continuous duty systems even with the turbine at high steam flow. However, to ensure sufficient thermal capacity, the condenser cooling water system capacity would need to be increased 0.5% full power for every 1% full power of steam bypass flow. This is potentially a significant cost extra for either a lake water or a cooling tower condenser cooling system that operates at lake or ambient air temperature respectively.

An alternative approach is to add a smaller separate steam bypass system that does not use the turbine condenser. The separate steam bypass condenser would be in addition to the steam

bypass to the turbine condenser. The separate steam bypass condenser would be used only for daily electrical load cycling and maneuvering at high turbine power. The size of the separate steam bypass condenser would be selected to match the required load cycling or maneuvering. It can also be used to supplement the steam bypass to the turbine condenser during full load rejections and grid blackouts. If the unit was required to return to full electrical power immediately after a load rejection or grid blackout then the capacity of the separate steam bypass system should be sufficient to handle the total steam flow from the reactor at full power. Typically that would be at most 40% full power capacity for the separate steam bypass system if the unit also had a 60% steam bypass to the turbine condenser. Some new reactor designs, such as the ACR1000 reactor, have some reactor maneuvering capability so the separate steam bypass system could be smaller than 40%.

If a separate steam bypass system were provided, the condensate that is returned to the unit steam generators could be designed for much higher temperatures and pressures. This would significantly reduce the physical size of the separate steam bypass system and reduce the pump power needed to return the condensate to the unit steam generators. Because the steam bypass energy is not being used for electrical production, thermal efficiency is not an issue and condensing the steam down to lake water temperature is not necessary.

The existing CANDU units would not likely be able to incorporate an improved continuously rated steam bypass to the turbine condenser due to physical restrictions of the existing plant design. For example the physical separation between the turbine exhaust and the condenser cooling tubes is inadequate to manage the erosion problem. However, a smaller sized separate steam bypass condenser could potentially be added close to the steam generators on top of the turbine/reactor auxiliary bay roof. Some engineering studies would be required to confirm this location could be used to reduce the pipeline costs and site space requirements.

Sufficient separate steam bypass system capacity could be provided to existing CANDU units so that without the need to maneuver the nuclear reactor power, the unit's generator output can:

- load cycle,
- load maneuver,
- allow the speed governor to lower generator power during grid disturbances,
- provide frequency control within a grid island,
- provide automatic generation control within a grid island, and
- participate earlier in the grid restoration process following a grid blackout.

The separate steam bypass system will also enable nuclear units to compensate for variable wind and solar generation and contribute to the peak load demand when excess nuclear capacity is available typically in the spring and fall.

This should reduce the demand for gas-fired generation that in turn will reduce greenhouse gas emissions. Higher fuel cost natural gas fired generators would then gradually take on the role for which they are most suited. They would compensate for unexpected losses of hydraulic or nuclear units and for unexpected increases in customer loads (ie: generation reserve) and for

emergency power during storms that separate their local communities from the bulk transmission system.

A potential future environmental benefit of nuclear maneuvering using a separate steam bypass system is that the bypassed steam could be made available to a district heating system at reasonably high pressure and temperature. For example, if provincial electrical planners and municipal land planners co-operated, it should be possible to develop industrial parks adjacent to nuclear sites so that the bypassed steam could be used to offset natural gas fuel that would typically be used for water, space and process heating. For safety reasons, an isolating heat exchanger would be required to ensure radioactivity does not leave the nuclear site in the event of a steam generator tube leak. The former Ontario Hydro had many years of experience running the Bruce site steam distribution system using steam from the 4 Bruce A reactors via a steam transformer plant (a form of isolating heat exchanger). The system was one of the largest district heating systems in the world with a design capacity of approximately 1,000 MW thermal because it supplied the heavy water plant industrial complex at that time.

2.4. Turbine Electro-Hydraulic Oil Reservoir and Pumping Capacity

Sufficient turbine electro-hydraulic oil reservoir and pumping capacity should be provided to satisfy daily load maneuvering and grid restoration load cycles. This is especially important if the separate steam bypass system control valves are electro-hydraulic powered and are functionally integrated with the turbine electro-hydraulic governor valves, as is the practice in certain other jurisdictions.

2.5. Energizing the Outgoing Transmission Line

The capability to energize the transmission line leaving the nuclear unit switchyard and to safely clear (isolate) that line should it be faulted, without damage to the electrical equipment at the plant, should be provided. This capability allows the grid operator to use nuclear units within a grid island and take advantage of the dynamic stability advantages of nuclear units with their large size and fast, electro-hydraulically controlled speed governors with large amounts of spinning reserve (represented by the steam bypass flow). Participation by nuclear units earlier in the grid restoration process significantly reduces the total time required to restore normal grid operations following a grid blackout. The older Ontario fossil and hydraulic units (and the current wind and solar units) are not large enough and/or fast enough to be able to provide this performance advantage, as we saw during the August 2003 blackout.

2.6. Grid Island Frequency Control/AGC Function

The control capability for the nuclear operator to manually engage an automatic grid island frequency control/AGC function at an operator selected fixed frequency value (typically at or slightly higher than 60 Hz) when a grid island forms around that nuclear unit should be provided. During grid island formation following a major disturbance and during grid restoration following a blackout, a significant amount of time and attention is required by various operators to manually control grid island frequency. If it drifts too high or low during the restoration process the generating units will trip off-line and that will make the restoration process more difficult and

time consuming. A large nuclear unit can act as an anchor unit if it has a steam bypass system capability. It can automatically control (anchor) the grid island frequency close to 60 Hz. This would free up the operators involved in the restoration process to monitor and co-ordinate the restoration and not be preoccupied with minute-to-minute frequency control duties.

2.7. Over-Ride of the Speed Governor

A requirement should be included to prohibit the overall unit control system from over-riding the turbine speed governor control action except when plant process parameters exceed their operating limits. The current overall unit control systems over-ride the speed governor when the turbine follows the reactor power level. This is the usual control mode at CANDU units in Ontario because it maximizes power production without exceeding licensing power limits. This over-ride exists because the present steam bypass system is not rated for continuous use.

A separate steam bypass system rated for continuous use will also allow the overall unit control system to allow the speed governor to lower generator power when grid frequency is high (typically in a grid island situation or during grid restoration). The present nuclear plant overall unit control system over-rides the speed governor demand when frequency deviates slightly from 60 Hz. Providing speed governor support to the grid is a fundamental dynamic stability requirement for all interconnected generators on the grid. When a large nuclear unit does not participate in governor speed control, the stability of that grid island is reduced. If nuclear generation represents a large fraction of the total generation within the grid island, and if those generators do not provide speed governor support, then the island is no longer dynamically viable and it can collapse and black out.

For example, during the Grand Valley tornado event in the late 1980's an island formed around the Bruce site and surrounding communities. The overall unit control system at the Bruce A unit that was still connected to the grid island tried to over-ride its own speed governor. Fortunately the unit operator, who was doing a generator panel test at the time, spotted the speed governor over-ride and manual disabled it before the unit was driven up through its high frequency trip. The island survived and continued operating until the island was reconnected to the Ontario main grid several minutes later. Grid frequency was well behaved and stable within the island at the operator established manual frequency setpoint.

2.8. Turbine-Generator Pressure Unloading Gear

A more graceful (earlier to start but slower to act) steam pressure unloading gear should be specified. The current main steam pressure unloading gear to protect the reactor and turbine acts too late (90% of nominal pressure) and too fast (10% full power/sec) and effectively takes the unit to zero output even if the gear is triggered momentarily. During grid island operation if the nuclear generation is a significant fraction of total generation, this can lead to a collapse of the island. The loss of generation happens so rapidly that the other unit speed governors within the grid island cannot cope with the large sudden drop in frequency. Also, the operators cannot compensate for the loss in such a short period of time by shedding loads. While the present fast unloading gear should be retained for safety reasons, a much slower gear that operates earlier should provide sufficient time for other generators to pick up the load and terminate the

frequency drop before the island collapses. The precise trigger point and rate of unloading can be determined by simulation studies.

2.9. Turbine-Generator Load Limit Gear

An accurate, high resolution, load limit gear capable of being controlled by the overall unit control system should be specified. Nuclear reactors are not permitted to operate at reactor power levels beyond their maximum licensed limits. The turbine/generator often has additional capacity in its governor control valves. To prevent rapid steam generator depressurization most turbine generator manufacturers offer a load limit gear that can be set manually by the operator or in some cases by the automation equipment. Unfortunately, some load limit gears do not have sufficient accuracy or resolution to position the gear precisely. As a result these gears are often set too high above the reactor power level. During a grid disturbance resulting in low frequency (eg: a grid islanding event) the additional steam demand by the turbine governor system can cause a rapid steam generator depressurization and trigger the fast pressure unloading gear mentioned in the previous section. That would typically cause the unit to rapidly run back to zero load and the grid island would collapse. The precise accuracy and resolution that is required can be determined by simulation studies.

2.10. Electrical Generation Runback Gear

It has been a common practice in Ontario to deploy generation rejection schemes as a control aid to improve system transient stability and voltage stability. This type of special protection system is currently available to maximize the output of the Bruce nuclear site. While generation rejection is effective in improving transient stability, past planning studies had indicated that generation runback can be more effective in enhancing voltage stability. It is suggested that the system planners identify if there is any risk of encountering voltage instability problems in Ontario with future generation configurations (perhaps under outage conditions), and if so, determine whether the grid performance can benefit from installing generation runback facilities at the nuclear units. If so this capability should be specified.

2.11. Maximum Time to Reconnect to the Grid

The maximum time required to reconnect to the grid following a load rejection or grid blackout should be specified. One hour is suggested. That gives the nuclear operator time to confirm the plant's process and safety systems are functioning normally and permit the units to participate in grid restoration activities earlier in the process.

2.12. The Maximum Time to Return to Full Electrical Power

The maximum time required for the nuclear unit to return to full electrical power, following a load rejection or grid blackout, should be specified. Current CANDU plants lower reactor power to about 60% following a load rejection or grid blackout. This disturbs the reactor flux distribution in the reactor core and this limits the maximum reactor power levels for a period of time from several hours to up to 24 hours depending on the reactor design. However, a modest amount of separate steam bypass capacity can significantly reduce this time. To achieve a 4 hour

target restoration time for all grid customer loads, nuclear units would be required to return to full power within 4 hours also. In any case, time periods exceeding 8 hours are not recommended due to the consequential damage to customer facilities due to freezing during a blackout in the coldest winter months.

3. Project Requirements

In addition, to the technical requirements above, the following overall project requirements did not appear to the public to have been adequately dealt with in the production of the procurement documents. If they were not considered they should be. If they have been adequately dealt with an explicit statement should be issued by the responsible organization. The specific issues are:

1. Maximum nuclear unit size on the Ontario grid,
2. Functional independence of each unit,
3. Type of nuclear fuel permitted in Ontario,
4. Minimum number of units purchased per site,
5. Geographic location of the new nuclear units,
6. Quality assurance requirements, separation of roles and reporting relationships

These items are discussed in more detail in the sections below.

3.1. Maximum Unit Size

In the past, to avoid additional cost for spinning and transmission reserve on the grid, each unit's size was limited to a maximum of about 5% of the on-line generating capacity of the Ontario system. Some potential bidders of nuclear units have unit sizes that would exceed this limit for the Ontario grid. If this limit is still prudent it should be explicitly mentioned in the specifications. If it is not required then the bidders should be advised what economic evaluation penalties will be imposed for any additional spinning or transmission reserve requirements for excessively large unit sizes.

3.2. Requirements for Functional Independence of Each Unit

The extent of functional independence of each unit for a multi-unit site should be specified to limit the required spinning and transmission reserve for the grid. The objective is to either:

- limit the shock to the electrical grid, when a problem occurs, to a level of severity that the grid is designed to cope with, or
- ensure there is sufficient decision and action time for the IESO operators to reconfigure the grid before the problem causes the grid to collapse or inter-tie limits to be violated.

For illustration purposes some examples that need to be addressed in the specifications are:

- common cooling water intake, fore-bay and discharge,

- common main control room complex,
- common switchyard,
- common transmission tower or corridor,
- common communication and protection equipment,
- common water treatment plant.

3.3. Type of Nuclear Fuel Permitted in Ontario

Ontario has always prided itself with not having developed enriched uranium capability, that it could manufacture its own fuel, and that it was not dependent on a relatively few foreign enriched uranium suppliers for its nuclear power program. The recent procurement process allowed only enriched uranium fuelled reactors to be proposed. This is a major strategic change for Ontario and it has had little or no public input or discussion. The use of enriched uranium fuel adds a level of safety concerns and public resistance due to weapons proliferation/diversion and potential for out-of-core reactivity accidents in the new fuel storage and spent fuel storage areas. It also means Canada and Ontario can no longer manufacture its own nuclear fuel from mine-to-reactor. If Ontario does intend to purchase enriched uranium reactors some effort to get the public on side is necessary before the plant is ordered otherwise it could result in significant and costly delays if the public opposes the plant startup during the licensing process.

3.4. Minimum Number of Units Purchased per Site

The former Ontario Hydro (now OPG) financial data for its nuclear multi-unit generating sites shows that the construction indirects (temporary facilities and tooling required to construct the plant), engineering and licensing costs result in a very significant additional cost for the first unit. These are significantly higher for a nuclear project compared to non-nuclear projects. These costs are minimal for the subsequent units. Consequently, the energy costs from a multi-unit nuclear site drops significantly with each additional unit that is built but especially so for the first 4 units.

Also, the cost of equipment for multi-unit plants decrease with the number of units purchased. These costs are more difficult to determine from the former Ontario Hydro financial records because the costs of one unit or one set of pumps or one set of valves is not explicitly identified in the tenders compared to the actual orders that took place for multi-unit sites (typically 4 sets). We know from experience that manufacturing setup times will drop and even manufacturing techniques will change if a sufficient number of the same items are purchased. Volume manufacturing results in a lower unit price. This volume purchasing cost curve means the equipment price for 1 unit will be more than the unit price for 2 units and much more than the unit price for 4 units. Increased purchasing volumes may also help to obtain additional local economic development opportunities from suppliers. This is important because even CANDU reactors use a considerable amount of equipment from foreign suppliers who are prepared to offer local benefits to secure an order.

The former Ontario Hydro experience on various projects also demonstrates that the more work that is done at a factory, the lower is the cost of the project. Work at site is expensive because higher cost skilled trades are required and the large physical size of the work site lowers

productivity significantly. The current size of nuclear units preclude the fabrication and assembly of the complete unit in the factory, but there are opportunities for more factory pre-fabrication of assemblies, provided sufficient engineering lead time is incorporated into the project schedule.

The CNSC has established up-front high-level technical requirements in the CNSC regulatory document RD-337 "*Design of New Nuclear Power Plants*", September 2008. As such, the over-riding principles are clear, have been commented upon by all stakeholders, and have been agreed to by the Commission. In addition, the CNSC staff has established the pre-project vendor design review service specifically intended to permit potential vendors to understand the regulatory requirements and therefore minimize regulatory risk. Consequently, it is unlikely that "major new regulatory changes" would be introduced during the construction of a new nuclear plant.

However, it is not these high level regulatory requirements that cause the greatest concern to owners and investors. As the final design, analysis and construction of any new nuclear unit progresses, problems are often discovered with respect to meeting various high level regulatory requirements. Sometimes the problem is due to a design or construction error. Some problems can be resolved by moderate design changes or reconstruction without a significant impact to the cost, schedule or performance of the unit. But invariably, a few are often impossible to resolve without significant cost, schedule or performance impacts especially on the first unit of a new or improved design. The larger the unit size the larger the cost over-run if a problem surfaces. This is due both to the higher cost for a larger unit but it is also due to the longer construction schedule for a larger unit. The resulting higher interest charges during construction due to a delay and the higher labour costs to carry project staff for a longer period of time can add up rapidly.

If the in-service date of the 2nd and subsequent units are properly staggered to accommodate the potential delay on the first unit, the delays on the 2nd and subsequent units will be minimal. However, the total schedule period between the first and last unit must be sufficiently short that major new changes to international safety standards are not imposed on the subsequent units compared to the first unit. Essentially this means all multiple units at the site should be identical and be designed and constructed to the same code effective date. Unfortunately, the larger the nuclear unit, the more difficult it is to achieve an optimum separation of in-service dates for a multi-unit site.

The former Ontario Hydro project financial data shows that the first unit of a multi-unit site is usually significantly over-budget and behind schedule. However the situation improves dramatically with each subsequent unit as construction efficiencies are realized until the 4th unit when the actual cost and construction time are significantly below the actual cost and construction time for the first unit. The former Ontario Hydro experience, schedule data and financial data demonstrate that the minimum number of units that yield a reasonable cost per MW for a nuclear station site is four units or greater.

The Darlington site was an exception because it was subjected to several schedule revisions during its construction. Darlington was also constructed during the highest interest rate period in several decades and during a relatively high inflation period. Several technical problems caused further delays on the first unit that also delayed the subsequent three units, which due to earlier rescheduling were substantially complete.

The former Ontario Hydro project financial data also shows that on large nuclear projects, technical problems, schedule delays and capital cost over-runs can easily overwhelm any cost advantage of larger unit sizes. Darlington was designed with features from Bruce A and B and CANDU 6 and was projected to cost less per MW due to economies of scale of the larger units and cheaper to run due to lower staffing costs per MW. However, the technical problems drove up the capital cost well beyond the offsetting economies of scale and reduced staffing cost per MW. "Larger" in the nuclear business is often not necessarily "better". Technical and schedule risk are not unique to CANDU. AREVA, the world's largest nuclear supplier, is currently experiencing significant delays in Finland on its large improved Gen III+ PWR reactor project.

The largest cost component of nuclear energy is by far the capital cost of the plant. This suggests that when technical and schedule risks are included, a site with four smaller units of a more established design would produce lower energy costs per MWh than a site with two larger reactors with a new design.

3.5. Geographic Location of Nuclear Units

There was some public discussion of locating the 2 new nuclear units at the Nanticoke site. However, there was no discussion of the benefit it would have on reducing the stranded generation east of Toronto if the 500 kV transmission corridor north of Toronto near Highway 407 was disabled. This is an important economic and safety risk factor to the province that needs to be addressed in the decision on where to locate new nuclear units.

The former Ontario Hydro (now Hydro One) has built a 500 kV transmission backbone in the province. Due to public resistance to placing the backup circuits north of the Hwy 9 corridor, the Provincial government at that time ordered the former Ontario Hydro to place both the primary and backup circuits along one corridor just north of Toronto near Hwy 407. The prior generation planning process had placed large generation capacity east of the eastern city limits of Toronto, but the load is much greater west of the eastern city limits of Toronto.

This means that a line disabling ice storm, tornado or airliner crash into the 500 kV corridor north of Toronto, between the Cherrywood Transformer Station and Claireville Transformer Station, will isolate almost 7,000 MW of nuclear generation and 2,000 MW of fossil generation east of Toronto. There is insufficient transmission line capacity at Saunders, Niagara Falls and Sarnia to move the power from Saunders through the USA grid and back into Ontario at Niagara Falls and Sarnia.

The phasing out of the coal fired plants, most of them west of Toronto, will make the generation/load imbalance described above even worse. However, the planned retirement of the Pickering B units in about 10 years will improve this imbalance. The OPA has been ordering gas fired plants west of the eastern city limits of Toronto and this will help rebalance the system. However, the size of the imbalance is still too large to avoid a potential bottleneck and extensive blackout if the 500 kV corridor north of Toronto should become disabled for an extended period of time. The recent cancellation of the Oakville gas fired plant has resulted in a lost opportunity

to reduce this imbalance. Efforts to reduce this imbalance should continue to receive high priority.

Placing the two new nuclear units at Darlington will make the generation/load imbalance worse unless an alternative 500 kV transmission route is developed that is sufficiently removed from the existing corridor north of Toronto. Unfortunately, the likelihood of public acceptance of a major new east-west transmission corridor is unlikely given recent experience in Newmarket and downtown Toronto.

While there is additional cost in licensing a new nuclear site such as at the Nanticoke site, the improvement to the 500 kV transmission system generation/load imbalance would reduce the impact and cost of the loss of the north Toronto corridor on the province.

At the very least, if no improvements are planned to reduce this imbalance, the public should be made aware of the load/generation imbalance and its impact on electrical supply if the 500 kV corridor north of Toronto is disabled. Those customers who are not prepared to accept an extended period of rotating blackouts in such circumstances can then take alternate measures of their own to back up their critical loads.

3.6. Quality Assurance Requirements, Separation of Roles and Reporting Relationships

The procurement specifications were not clear about which nuclear quality assurance standards were to be applied and the importance of the separation of roles and responsibilities and reporting relationships of the various organizations involved in the design, construction, procurement and commissioning of the reactors. Experience has shown that this is very important and if left to a vendor can lead to conflicts of interest, non-conforming products, schedule delays, cost over-runs and legal disputes with the owner. These should be precisely defined in the procurement specifications.

4. Additional Background Information

Additional background information has been included in Appendix A for those readers who would like additional information to better understand the operating characteristics of the electrical grid or CANDU nuclear units.

5. Acknowledgements

OSPE would like to acknowledge the industry stakeholders, OSPE members and other individuals who took time to review and offer comments and suggestions on the December 1, 2011 draft version of this document:

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(4) Colin Andersen, MA, CEO, Ontario Power Authority, Toronto

(5) David Newland, Director, Assessment Integration Division, Canadian Nuclear Safety Commission, Ottawa

(6) Tom Mitchell, M. Eng., President and CEO, and Bruce Boland, Senior Vice President, Corporate Affairs, Ontario Power Generation, Toronto

(7) Duncan Hawthorne, MBA, President and CEO, Bruce Power, Tiverton

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(10) John R. Muir, Director, Canadian Energy Policy, GE Energy, Mississauga

(11) Henk Van Ballegooyen, P. Eng.,Technical Advisor, Gryphon International Engineering Services Inc., St Catherines

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(13) Don Cryder, P. Eng., VP Sales & Marketing, ROMlight International (Canada) Inc., Concord

(14) Donald Jones, P. Eng.

(15) Bob Young, P. Eng.

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OSPE would also like to acknowledge the contributions made to this document by members of its Energy Task Force. They include:

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APPENDIX A

Background Information on the Electrical Grid and Nuclear Units

Ontario's Electrical Grid

The electrical grid in Ontario normally operates at a very stable frequency and voltage. This is because the electrical systems in the eastern USA and eastern Canada are interconnected into a very large grid of about 500,000 MW compared to Ontario's 25,000 MW. The North American Electric Reliability Corporation (NERC) and the Northeast Power Co-ordinating Council (NPCC) set electrical grid requirements for interconnected electrical systems in North America and the northeastern USA & eastern Canada respectively.

Primary frequency control is provided by the speed governors of the units that are operating on the electrical grid. Automatic generation control (AGC) provides a secondary control function. It controls inter-tie load flows and through an inter-area frequency correction signal assists in correcting any errors in frequency by increasing or decreasing generation. During grid island operation when the Ontario grid is not interconnected to other utilities, AGC provides a fine tuning function and ensures frequency is precisely 60 Hz.

Voltage control is mainly provided by each generating unit using a voltage control system that manipulates the generator's excitation system. In areas where the generators are not close enough to be effective, the grid contains various types of voltage compensation equipment to maintain voltage within acceptable ranges. Some local areas will need additional voltage compensation equipment when the coal fired units are permanently retired.

From time to time, grid voltages and frequencies will become abnormal for a period of time. This can happen due to disturbances such as a loss of a large generating unit, the loss of a large industrial load, the loss of a transmission line, separation from neighboring utilities, or any one of many other contingencies. Also, from time to time due to severe storms, infrastructure degradation or other infrequent circumstances the grid will experience a severe disturbance with which it cannot cope and the grid will collapse like it did in August 2003. Significant grid disturbances happen every few years but widespread blackouts typically occur only once every 30 or 40 years.

In Ontario in 2009, nuclear and hydraulic resources represented about 55% and 26% of energy production, respectively. Renewable generation such as solar and wind were about 2% of energy production but are a growing supply-mix component. Coal and gas fired generation made up the other 17%. By 2030 the Ontario electrical grid will provide about 13% more energy and the mix will be approximately 53% nuclear, 23% hydraulic, 12% wind, 8% gas fired, 2% solar and 2% bio-mass.

An important aspect of grid performance is the ability to recover from a grid collapse or blackout like we saw in August 2003. Ontario has 2 major strategies to restore the grid after a widespread blackout. One is to use hydraulic units from Niagara Falls and the 115 and 230 kV transmission system and the other is to use nuclear units at Bruce or Darlington and the 500 kV transmission

system. During the August 2003 blackout the Niagara Falls route was chosen for restoration for a number of technical reasons. Four nuclear units were left operating in their poison prevent operating mode using their steam bypass systems. The remaining nuclear units were shutdown.

Grid restoration begins by connecting one or more generating units to the transmission grid under control of the unit's speed governor to maintain frequency and then connecting some customer load. The frequency drops as the generating unit picks up the customers' load. The generating plant operators adjust the frequency back up to 60 hertz or slightly higher and the process then continues repeatedly in a step wise fashion until the whole system is up and running. During the restoration process if too much customer load is applied the frequency or voltage can drop below safe limits and the grid can collapse due to the operation of protective relays. The speed with which the process can progress is dependent on a number of factors including the generator unit size, and the response capability of the generating unit speed governor and the automatic voltage controller. Because Ontario's existing hydraulic and fossil fired units were designed back in the mid 1960's or earlier, they use mechanical and mechanical hydraulic governors which are not particularly fast acting with respect to speed/frequency control. Most of Ontario's CANDU units were designed after the mid 1960's when fast electro-hydraulic speed governors and fast static voltage regulation equipment became available. Consequently, Ontario's nuclear plants are the best equipped to support grid restoration.

Another problem that must be handled during grid disturbances is the possibility that one or more grid islands can form within Ontario. These islands each need frequency and voltage control. As load increases or decreases, the frequency in a grid island will fall or rise respectively. Steam turbines cannot operate at high power levels if they are near a turbine blade natural resonant frequency or fatigue failure could result. As a result, the frequency set-point for the speed governors within a grid island must be adjusted often to keep grid frequency close to 60 Hz as load changes. Currently this is done manually when a grid island forms, by generating plant operators after receiving authorization from the Independent Electricity System Operator (IESO) operator to adjust the plant's speed governor set-point.

Voltages in a grid island will also vary depending on load conditions. Manual adjustment of the generator excitation voltage set-point is required by a generating plant operator after receiving authorization from the IESO operator. The set-point must be adjusted to keep voltages within acceptable tolerances. Fortunately, voltages are not as variable as frequency and the voltage set-point can be set manually less frequently than the speed set-point.

If frequencies and voltages are not kept within acceptable tolerances, various protective systems located within generating plants, transmission and distribution facilities or customer facilities will cause the grid to collapse and blackout. This is essentially what happened during the August 2003 blackout.

Power Maneuvering

Customer demand varies throughout the day and among seasons. The seasonal variation can be substantially managed by shutting down units for extended annual maintenance during the low demand seasons, typically spring and fall for Ontario.

Daily demand variations are more difficult to manage by shutting down units because of the wear and tear that it causes especially on high pressure and high temperature generating units such as fossil fired plants, bio-mass plants and nuclear facilities. Day-to-day and hourly variations are therefore typically managed by maneuvering the power output of generating units in one of 3 ways – load cycling, load maneuvering and automatic generation control (AGC). Day-to-day variations can also be accommodated by shutting down units that are capable of being shutdown daily and can return in a day or two to meet peak demands. Technically these units would ramp their output to zero and then disconnect from the electrical grid until the next day when they would return to service. Many gas fired plants are designed to be shut down daily.

Load cycling involves moving the unit's output down then up only once each day usually at night using dispatch orders from the IESO operators. Hydraulic and gas fired units have load cycling capability. Relatively few CANDU units are able to load cycle and those that do have a number of restrictions with respect to size of load change, time a lower load and time to return to full power. Consequently they are not very flexible and are seldom used for load cycling.

Load maneuvering involves more frequent power changes in both up and down directions up to once every 5 minutes using dispatch orders from the IESO operators. Hydraulic and gas fired units have load cycling capability. To minimize wear and tear the reversals in power direction on any specific unit are typically minimized. This means the power is changed at several units in a co-ordinated manner to achieve the overall maneuvering result without unreasonable hardship on any one unit. Existing CANDU units cannot load maneuver because the reactors do not have adequate operating margins to accommodate the neutron flux distortions that result and the steam bypass systems are not rated for continuous use.

AGC is fully automatic and controls on a second-to-second basis. AGC enables the IESO operators to more easily manage the 5 minute dispatching orders. Because of the frequent power changes and reversals, AGC functionality is usually provided by hydraulic units with maneuvering capability such as the Beck station at Niagara Falls. No current CANDU units have the engineered systems to provide AGC functionality.

In the case of wind and solar generating units, these are currently considered non-dispatchable. That means they generate whenever nature provides the energy to produce power. This is done to ensure the maximum amount of green (non-emitting, sustainable) energy is used by the grid. Ontario's long term energy plan intends to add 9000 MW of wind , solar and bio-mass up to a total capacity of 10,700 MW by 2030. Most of this will be wind. Even in a geographically large province such as Ontario, the variability of wind on the worst days of the year can exceed 90 % of capacity. Consequently, maneuvering capability will be required for most of this wind and solar capacity to compensate for its variable output. The worst case situation is when wind is not available during the daily peak but is fully available during the daily low. This means that there needs to be sufficient maneuverable generation to compensate for the reduced customer demand and the unwanted wind generation. This maneuvering capability must be provided by gas, bio-mass, hydraulic and nuclear, typically in that order of merit.

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Ontario Electrical Grid and Project Requirements for Nuclear Plants

If an electrical grid does not have sufficient maneuverable generation to manage changing customer loads and variable wind and solar generation, then the electrical grid becomes unmanageable. This is one of the reasons a number of North American utilities have notified wind developers that they cannot add more than a specific amount of wind generation to their electrical grid systems.

In Ontario, the long term energy plan indicated that on the worst case days, approximately 8,800 MW of power maneuvering is needed for customer load variation. By 2030 the maximum customer load variation in a day could reach almost 10,000 MW. This variation can be managed by power maneuvering and by shutting down units that can be restarted the next day or two. Approximately 9,000 MW of maneuvering capability will also be needed for variable wind and solar generation by 2030. The combination of these two does not add up to 19,000 MW because wind and solar variability and customer demand variation do not coincide. However, the total amount of hour-to-hour maneuvering capability during the worst days is substantial.

Each type of generating unit has its unique power maneuvering characteristics such as ramp rates, quiet time between ramps, quite time between ramp reversals, and minimum power output levels that it can maneuver down to. Those characteristics are related to the technology used to generate the power such as nuclear, gas, hydraulic, etc. They are also related to the type of engineered systems that have been included in the design of those generating units to improve their maneuvering capability.

Maneuvering power levels comes with a number of costs and other burdens. Wear and tear on the unit increases because the process conditions are not at their optimum design points, operator workload increases to monitor the power changes and their effect within the unit and the unit's energy efficiency suffers.

In the case of hydraulic units, the minimum power level each unit can operate at in the short term (hours) is dependent on a number of site specific factors. These include:

- whether there is automatic remotely operated equipment to bypass or spill water around the turbine,
- whether the unit has water storage capability upstream,
- whether there is a minimum flow through the unit that must be maintained to ensure water quality and/or shoreline water levels are within acceptable ranges, etc.

For all these reasons, the minimum amount of hydraulic generation in Ontario is approximately 40% of the maximum rated hydraulic capacity. Therefore for Ontario's grid with 8,127 MW of hydraulic generation in 2010, a maximum of approximately 60% or 4860 MW is available for power maneuvering. It is important to note however, that on any particular day, due to water availability or other factors, the actual maneuvering capability can be lower than the maximum. For example on January 18, 2011 when electricity prices were negative for a couple of hours due to excess base generation, only 3,200 MW of maneuvering capability was available. Ontario's long term energy plan intends to increase hydraulic generation by about 900 MW by 2030. Consequently hydraulic maneuvering capability will rise to only about 5,400 MW maximum.

In the case of gas fired and bio-mass units, there are a number factors that will limit the amount of power decrease that can be achieved with power maneuver and or unit shutdown. These include combustion stability, equipment temperature and stress limitations, other wear and tear factors, must-run energy contracts, etc. Typically a combination of unit shutdown and maneuvering can lower total gas fired generation output down to about 25% of capacity. Therefore, with approximately 9,000 MW of gas generation available in Ontario over the next 20 years, only about 6,700 MW maximum of maneuvering capability is available.

As one can see, with only 12,100 MW maximum of hydraulic and gas fired maneuvering available by 2030, other means must be found to allow almost 10,000 MW of variable wind and solar capacity to be added by 2030 and to also handle about 10,000 MW of customer load variation.

In the case of nuclear plants, the minimum power level that the unit can operate at is dependent on whether it is the reactor or the turbine/generator that is changing power. If the reactor power is changing power then reactor physics considerations determine the maneuvering characteristics. If the reactor remains at high power and if the unit has a robust steam bypass system, then the turbine/generator power can be maneuvered down to whatever load the steam bypass system can accommodate. Maneuverable capability is an electrical grid system established requirement. However, a maneuvering capability of more than about 40% of full power for a nuclear unit has a significant cost associated with it. The reason is that it requires either a much larger heat rejection capability at the turbine condenser or a much larger separate steam bypass condenser than can be accommodated physically close to the steam generators.

CANDU Nuclear Units

Nuclear plants are designed and built to a set of procurement specifications. These in turn are developed based on a set of requirements established by regulatory bodies. The Canadian Nuclear Safety Commission (CNSC) establishes the safety requirements and licenses the unit based on a safety case submitted by the owner/licensee. The Energy Minister (MOE), the Ontario Power Authority (OPA) and the IESO establish the various electrical grid requirements that nuclear unit owners are required to meet before they are given contracts to build the unit or are permitted to connect to the electrical grid.

Each type of nuclear generating unit has its own unique performance advantages and disadvantages with respect to electrical grid operation. However, the disadvantages can be compensated for by careful engineering design. Existing CANDU nuclear units have been made more “grid friendly” than USA PWR and BWR reactors. This was accomplished by incorporating additional operating margins in the plant systems and by including a steam bypass system, to accommodate the requirements of the Ontario electrical grid at the time they were designed in the 1960’s and 1970’s. They can be made even more grid friendly by additional engineering measures.

CANDU reactors fuel on-line while they operate. This means they do not carry a lot of excess reactivity in the core and their operating characteristics are the same throughout their operating cycles between maintenance outages. When a CANDU nuclear reactor operates at high power, if

it is suddenly shutdown, a buildup of neutron absorbing radioactive isotopes occurs in the reactor core. These isotopes, mainly Xenon 135, will prevent the reactor from restarting for approximately 2 days until those isotopes decay off. It then takes up to 1 day for that reactor to start up and reach full power. Nuclear power engineers refer to these isotopes as "poisons". The reactor is said to be "poisoned out" or undergoing a "poison outage" during the period when it is unable to restart.

A reactor can avoid poisoning out if it can keep its reactor power level sufficiently high to effectively burn the poisons as fast as they are produced. When the unit is not connected to the grid, this can be accomplished by diverting steam from the turbine to a steam bypass system. For CANDU units the power level needed to avoid a poison-outage is typically 60% full power or greater after an extended period of operation at the 100% level. When a nuclear unit is operating disconnected from the grid in an effort to avoid a poison outage, it is said to be operating in a "poison prevent mode".

NERC and NPCC set the electrical grid requirements for interconnected electrical systems. However, NERC and NPCC requirements do not address some unique Ontario grid requirements for dynamic stability and for blackout recovery following a grid collapse. Because of Ontario's heavy reliance on nuclear power (55% of energy supply in 2009) it is not practical to follow the USA practice of shutting down nuclear plants during grid disturbances and blackouts.

The current CANDU units are designed to operate through electrical grid disturbances that affect frequency and voltage. The Bruce B and Darlington units can also operate in a "poison prevent mode" following a load rejection and grid blackout so they can reconnect and supply the grid shortly after the event. A load rejection is when the generator is disconnected from the electrical grid by protection relays. The grid may or may not still be operating with acceptable voltage. A grid blackout is when the bulk transmission system has no voltage.

Nuclear plants in the USA only produce about 20% of their grid's electrical energy. Since most electrical grids maintain about 15 to 20% reserve generation in the event of equipment failures, there is sufficient backup generation in the USA to offset the loss of their nuclear plants. USA nuclear plants therefore are not designed to survive either a grid disturbance or a blackout. In the USA, when the grid collapses and blacks out, the reactors are shutdown and are not restarted until the electrical grid has been sufficiently restored to provide stable voltages and frequency within normal operating ranges. Effectively, that means USA reactors do not participate in grid restoration activities. This was the case following the August 2003 blackout. An EPRI (Electric Power Research Institute) study in the 1980's on grid electrical disturbances found that only about 25% of their nuclear plants were able to remain operating during a grid disturbance and load rejections. At the time the EPRI report was published Ontario's CANDU nuclear units had a 90% success rate in operating through a grid disturbance and load rejections.

In Ontario, nuclear reactors have not participated in grid restoration activities immediately following a grid blackout. However, most need to reconnect in a reasonable period of time or it would take several days to restore the grid to normal operation, as it did in August 2003. During the August 2003 blackout, the 4 CANDU units at Bruce B and Darlington that were operated in the poison prevent mode were reconnected to the grid in the period from 3 to 6 hours after the

blackout. However, 7 other CANDU units that were operating at the time were shutdown and poisoned out. There is not enough reserve generation or interconnection capacity to neighboring utilities available to compensate for the loss of a large fraction of Ontario's nuclear generation (currently approximately 12,000 MW in total).

Continuous reactor power changes on a minute-to-minute basis pose concerns with respect to equipment wear and tear. Power changes contribute to significant additional operator workload to monitor the reactor's spatial neutron flux that changes with time after every change in power level and also to monitor other plant parameters. In order to change reactor power, there must be sufficient operating margin to accommodate the distortion to the spatial neutron flux that follows a power change so that fuel bundle limits are not exceeded. Current CANDU plants have lost much of their operating margins due to equipment aging, power up-rates and other factors. Consequently, current CANDU units in Ontario do not load cycle or load maneuver their reactor power. Extensive research, development, simulation, analysis and design changes would be required to demonstrate the existing reactors could handle a significant electrical load maneuver using reactor power maneuvering.

In Ontario, the nuclear plants were designed with a number of capabilities that are not all available at the existing fossil and hydraulic plants:

- large real power (MW) capability;
- large reactive power (MX) capability;
- fast electro-hydraulic speed governors (except Pickering A);
- fast static excitation systems;
- fast steam bypass capability for load rejection and blackouts.

These capabilities add considerable frequency and voltage stability to the Ontario electrical grid when the nuclear units are operating and within any local electrical island to which a nuclear unit is connected. The reverse is true when they are not operating especially in a grid island after a major disturbance or during grid restoration following a blackout. The additional frequency stability during grid restoration is a direct result of steam bypass flow being available as immediate spinning reserve via the turbine's electro-hydraulic speed governor. This was confirmed by computer simulation studies at the former Ontario Hydro (now Ontario Power Generation – OPG and Ontario Power Authority - OPA) during the 1980's.

Steam Bypass Systems and their Role in CANDU Units

Fast steam bypass systems rated for infrequent use were originally incorporated into Ontario's CANDU units during their design to handle load rejections and grid blackouts. These events occur once every few years and only for several hours so the steam bypass systems did not need to be rated for continuous duty.

More robust continuous duty steam bypass systems are now available. These systems can provide effective de-coupling between the reactor and the turbine/generator so that electrical power can be maneuvered without affecting reactor power. The capacity of the steam bypass system can be set by the amount of load maneuvering that is required.

Load maneuvering using steam bypass systems may be a viable economic alternative to building hydraulic pumped storage capacity with its associated transmission line and significant environmental footprint.

New nuclear units have more options to achieve maneuvering capability, compared to existing units. These include one or more of the following: maneuvering adjusters (or grey control rods), several types of improved continuous duty steam bypass systems, and additional operating margins in the various plant systems to provide either reactor or generator maneuvering modes.

It should be noted that adding additional operating margins is very expensive in lost energy production. Because nuclear plants have low fueling costs, they operate at maximum output most of the time. Any capability that is held in reserve for maneuvering represents lost low cost energy output. Therefore, if total steam bypass operating time is low, it can be more economic to operate the reactor at its highest licensed power output all of the time and use a steam bypass system to temporarily cut back on generator output when necessary.

For new reactors, a more robust de-superheated steam bypass system to the turbine condenser similar to those available on some more recent fossil-fired plants could be considered. This type of steam bypass system has attemperators to de-superheat the steam before it enters the condenser vapour space, improved physical separation between the turbine exhaust and condenser cooling tubes, more robust condenser cooling tubes, better steam distribution baffles, improved bypass spray nozzle designs, etc. These changes result in a much lower wear and tear of condenser internal components. These bypass systems are typically rated as continuous duty systems even with the turbine at high steam flow. Some additional analysis would be necessary to determine if these bypass systems could be used in a new nuclear reactor to successfully operate continuously for most of the day, every day, to enable electrical load cycling and maneuvering while the reactor remains at full power.

Existing CANDU units have a number of physical constraints on the turbine, condenser, reactor and site layout that for practical purposes limits the options that can be considered. A continuously rated, modestly sized (10 to 40% full power capacity), air cooled, separate steam bypass system installed on the turbine/reactor auxiliary bay roof should be practical to retrofit into existing CANDU units during their refurbishment programs. Some changes would be necessary to the plant control systems and feedwater heating systems to allow this mode of operation to occur without disturbing the reactor. However, these are not overly onerous engineering design challenges. An AGC (second-to-second automatic load change) capability would require additional changes to the overall unit control systems to protect the reactor from an off-site AGC signal failure.

Having a modestly sized, robust, separate steam bypass system would get around the problem of inadequate operating margins to maneuver the reactor power. There is a cost involved however. In addition to the cost of the steam bypass system, this mode of operation would cost 0.5 cents per kWh for fuel costs. Fortunately the fuel costs are low compared to forcing nuclear units out of service for several days due to excess base load generation or paying our neighbouring utilities to accept our surplus base load energy. An economic evaluation would need to be done to justify

a steam bypass capability over other methods of managing excess base load generation such as pumped hydraulic generating units.

Using nuclear plants to compensate for wind and solar variability is also technically achievable. However, due to the longer potential operating times in this mode, it is more economic to use other generating units such as gas fired, bio-mass and hydraulic to compensate for wind and solar variability first and only use nuclear steam bypass when all other forms of maneuvering is exhausted. To employ nuclear maneuvering to allow more wind and solar capacity onto the grid requires that a robust steam bypass system is installed in the nuclear unit before the additional wind and solar capacity is added. Because new nuclear units can take 10 years or more to build from initial approval, retrofitting existing nuclear units during their refurbishment programs with modestly sized, robust, separate steam bypass systems is a shorter term solution.