

# 7. Performance of Nuclear Power Plants Affected by the Blackout

## Summary

On August 14, 2003, the northeastern United States and Canada experienced a widespread electrical power outage affecting an estimated 50 million people. Nine U.S. nuclear power plants experienced rapid shutdowns (reactor trips) as a consequence of the power outage. Seven nuclear power plants in Canada operating at high power levels at the time of the event also experienced rapid shutdowns. Four other Canadian nuclear plants automatically disconnected from the grid due to the electrical transient but were able to continue operating at a reduced power level and were available to supply power to the grid as it was restored by the transmission system operators. Six nuclear plants in the United States and one in Canada experienced significant electrical disturbances but were able to continue generating electricity. Non-nuclear generating plants in both countries also tripped during the event. Numerous other nuclear plants observed disturbances on the electrical grid but continued to generate electrical power without interruption.

The Nuclear Working Group (NWG) is one of the three Working Groups created to support the U.S.-Canada Power System Outage Task Force. The NWG was charged with identifying all relevant actions by nuclear generating facilities in connection with the outage. Nils Diaz, Chairman of the U.S. Nuclear Regulatory Commission (NRC) and Linda Keen, President and CEO of the Canadian Nuclear Safety Commission (CNSC) are co-chairs of the Working Group, with other members appointed from various State and federal agencies.

During Phase I of the investigation, the NWG focused on collecting and analyzing data from each plant to determine what happened, and whether any activities at the plants caused or contributed to the power outage or involved a significant safety issue. To ensure accuracy, NWG members coordinated their efforts with the

Electric System Working Group (ESWG) and the Security Working Group (SWG). NRC and CNSC staff developed a set of technical questions to obtain data from the owners or licensees of the nuclear power plants that would enable their staff to review the response of the nuclear plant systems in detail. The plant data was compared against the plant design to determine if the plant responses were as expected; if they appeared to cause the power outage or contributed to the spread of the outage; and if applicable safety requirements were met.

Having reviewed the operating data for each plant and the response of the nuclear power plants and their staff to the event, the NWG concludes the following:

- ◆ All the nuclear plants that shut down or disconnected from the grid responded automatically to grid conditions.
- ◆ All the nuclear plants responded in a manner consistent with the plant designs.
- ◆ Safety functions were effectively accomplished, and the nuclear plants that tripped were maintained in a safe shutdown condition until their restart.
- ◆ The nuclear power plants did not trigger the power system outage or inappropriately contribute to its spread (i.e., to an extent beyond the normal tripping of the plants at expected conditions). Rather, they responded as anticipated in order to protect equipment and systems from the grid disturbances.
- ◆ **For nuclear plants in the United States:**
  - Fermi 2, Oyster Creek, and Perry tripped due to main generator trips, which resulted from voltage and frequency fluctuations on the grid. Nine Mile 1 tripped due to a main turbine trip due to frequency fluctuations on the grid.

- FitzPatrick and Nine Mile 2 tripped due to reactor trips, which resulted from turbine control system low pressure due to frequency fluctuations on the grid. Ginna tripped due to a reactor trip which resulted from a large loss of electrical load due to frequency fluctuations on the grid. Indian Point 2 and Indian Point 3 tripped due to a reactor trip on low flow, which resulted when low grid frequency tripped reactor coolant pumps.

◆ **For nuclear plants in Canada:**

- At Bruce B and Pickering B, frequency and/or voltage fluctuations on the grid resulted in the automatic disconnection of generators from the grid. For those units that were successful in maintaining the unit generators operational, reactor power was automatically reduced.
- At Darlington, load swing on the grid led to the automatic reduction in power of the four reactors. The generators were, in turn, automatically disconnected from the grid.
- Three reactors at Bruce B and one at Darlington were returned to 60% power. These reactors were available to deliver power to the grid on the instructions of the transmission system operator.
- Three units at Darlington were placed in a zero-power hot state, and four units at Pickering B and one unit at Bruce B were placed in a Guaranteed Shutdown State.

The licensees' return to power operation follows a deliberate process controlled by plant procedures and regulations. Equipment and process problems, whether existing prior to or caused by the event, would normally be addressed prior to restart. The NWG is satisfied that licensees took an appropriately conservative approach to their restart activities, placing a priority on safety.

- ◆ **For U.S. nuclear plants:** Ginna, Indian Point 2, Nine Mile 2, and Oyster Creek resumed electrical generation on August 17. FitzPatrick and Nine Mile 1 resumed electrical generation on August 18. Fermi 2 resumed electrical generation on August 20. Perry resumed electrical generation on August 21. Indian Point 3 resumed electrical generation on August 22. Indian Point 3 had equipment issues (failed splices in the control rod drive mechanism power system) that required repair prior to restart. Ginna submitted a special request for enforcement

discretion from the NRC to permit mode changes and restart with an inoperable auxiliary feedwater pump. The NRC granted the request for enforcement discretion.

- ◆ **For Canadian nuclear plants:** The restart of the Canadian nuclear plants was carried out in accordance with approved Operating Policies and Principles. Three units at Bruce B and one at Darlington were resynchronized with the grid within 6 hours of the event. The remaining three units at Darlington were reconnected by August 17 and 18. Units 5, 6, and 8 at Pickering B and Unit 6 at Bruce B returned to service between August 22 and August 25.

The NWG has found no evidence that the shutdown of the nuclear power plants triggered the outage or inappropriately contributed to its spread (i.e., to an extent beyond the normal tripping of the plants at expected conditions). All the nuclear plants that shut down or disconnected from the grid responded automatically to grid conditions. All the nuclear plants responded in a manner consistent with the plant designs. Safety functions were effectively accomplished, and the nuclear plants that tripped were maintained in a safe shutdown condition until their restart.

Additional details are available in the following sections. Due to the major design differences between nuclear plants in Canada and the United States, the decision was made to have separate sections for each country. This also facilitates the request by the nuclear regulatory agencies in both countries to have sections of the report that stand alone, so that they can also be used as regulatory documents.

## Findings of the U.S. Nuclear Working Group

### Summary

The U.S. NWG has found no evidence that the shutdown of the nine U.S. nuclear power plants triggered the outage, or inappropriately contributed to its spread (i.e., to an extent beyond the normal tripping of the plants at expected conditions). All nine plants that experienced a reactor trip were responding to grid conditions. The severity of the grid transient caused generators, turbines, or reactor systems at the plants to reach a protective feature limit and actuate a plant shutdown. All nine plants tripped in response to those conditions in a manner consistent with the plant

designs. The nine plants automatically shut down in a safe fashion to protect the plants from the grid transient. Safety functions were effectively accomplished with few problems, and the plants were maintained in a safe shutdown condition until their restart.

The nuclear power plant outages that resulted from the August 14, 2003, power outage were triggered by automatic protection systems for the reactors or turbine-generators, not by any manual operator actions. The NWG has received no information that points to operators deliberately shutting down nuclear units to isolate themselves from instabilities on the grid. In short, only automatic separation of nuclear units occurred.

Regarding the 95 other licensed commercial nuclear power plants in the United States: 4 were already shut down at the time of the power outage, one of which experienced a grid disturbance; 70 operating plants observed some level of grid disturbance but accommodated the disturbances and remained on line, supplying power to the grid; and 21 operating plants did not experience any grid disturbance.

## Introduction

In response to the August 14 power outage, the United States and Canada established a joint Power System Outage Task Force. Although many non-nuclear power plants were involved in the power outage, concerns about the nuclear power plants are being specifically addressed by the NWG in supporting of the joint Task Force. The Task Force was tasked with answering two questions:

1. What happened on August 14, 2003, to cause the transmission system to fail resulting in the power outage, and why?
2. Why was the system not able to stop the spread of the outage?

The NRC, which regulates U.S. commercial nuclear power plants, has regulatory requirements for offsite power systems. These requirements address the number of offsite power sources and the ability to withstand certain transients. Offsite power is the normal source of alternating current (AC) power to the safety systems in the plants when the plant main generator is not in operation. The requirements also are designed to protect safety systems from potentially damaging variations (in voltage and frequency) in the supplied

power. For loss of offsite power events, the NRC requires emergency generation (typically emergency diesel generators) to provide AC power to safety systems. In addition, the NRC provides oversight of the safety aspects of offsite power issues through its inspection program, by monitoring operating experience, and by performing technical studies.

## Phase I: Fact Finding

Phase I of the NWG effort focused on collecting and analyzing data from each plant to determine what happened, and whether any activities at the plants caused or contributed to the power outage or its spread or involved a significant safety issue. To ensure accuracy, a comprehensive coordination effort is ongoing among the working group members and between the NWG, ESWG, and SWG.

The staff developed a set of technical questions to obtain data from the owners or licensees of the nuclear power plants that would enable them to review the response of the nuclear plant systems in detail. Two additional requests for more specific information were made for certain plants. The collection of information from U.S. nuclear power plants was gathered through the NRC regional offices, which had NRC resident inspectors at each plant obtain licensee information to answer the questions. General design information was gathered from plant-specific Updated Final Safety Analysis Reports and other documents.

Plant data were compared against plant designs by the NRC staff to determine whether the plant responses were as expected; whether they appeared to cause the power outage or contributed to the spread of the outage; and whether applicable safety requirements were met. In some cases supplemental questions were developed, and answers were obtained from the licensees to clarify the observed response of the plant. The NWG interfaced with the ESWG to validate some data and to obtain grid information, which contributed to the analysis. The NWG has identified relevant actions by nuclear generating facilities in connection with the power outage.

## Typical Design, Operational, and Protective Features of U.S. Nuclear Power Plants

Nuclear power plants have a number of design, operational, and protective features to ensure that

the plants operate safely and reliably. This section describes these features so as to provide a better understanding of how nuclear power plants interact with the grid and, specifically, how nuclear power plants respond to changing grid conditions. While the features described in this section are typical, there are differences in the design and operation of individual plants which are not discussed.

### ***Design Features of Nuclear Power Plants***

Nuclear power plants use heat from nuclear reactions to generate steam and use a single steam-driven turbine-generator (also known as the main generator) to produce electricity supplied to the grid.

#### **Connection of the plant switchyard to the grid.**

The plant switchyard normally forms the interface between the plant main generator and the electrical grid. The plant switchyard has multiple transmission lines connected to the grid system to meet offsite power supply requirements for having reliable offsite power for the nuclear station under all operating and shutdown conditions. Each transmission line connected to the switchyard has dedicated circuit breakers, with fault sensors, to isolate faulted conditions in the switchyard or the connected transmission lines, such as phase-to-phase or phase-to-ground short circuits. The fault sensors are fed into a protection scheme for the plant switchyard that is engineered to localize any faulted conditions with minimum system disturbance.

#### **Connection of the main generator to the switchyard.**

The plant main generator produces electrical power and transmits that power to the offsite transmission system. Most plants also supply power to the plant auxiliary buses for normal operation of the nuclear generating unit through the unit auxiliary transformer. During normal plant operation, the main generator typically generates electrical power at about 22 kV. The voltage is increased to match the switchyard voltage by the main transformers, and the power flows to the high voltage switchyard through two power circuit breakers.

**Power supplies for the plant auxiliary buses.** The safety-related and nonsafety auxiliary buses are normally lined up to receive power from the main generator auxiliary transformer, although some plants leave some of their auxiliary buses powered from a startup transformer (that is, from the offsite power distribution system). When plant power generation is interrupted, the power supply

automatically transfers to the offsite power source (the startup transformer). If that is not supplying acceptable voltage, the circuit breakers to the safety-related buses open, and the buses are reenergized by the respective fast-starting emergency diesel generators. The nonsafety auxiliary buses will remain deenergized until offsite power is restored.

### ***Operational Features of Nuclear Power Plants***

**Response of nuclear power plants to changes in switchyard voltage.** With the main generator voltage regulator in the automatic mode, the generator will respond to an increase of switchyard voltage by reducing the generator field excitation current. This will result in a decrease of reactive power, normally measured as mega-volts-amperes-reactive (MVAR) from the generator to the switchyard and out to the surrounding grid, helping to control the grid voltage increase. With the main generator voltage regulator in the automatic mode, the generator will respond to a decrease of switchyard voltage by increasing the generator field excitation current. This will result in an increase of reactive power (MVAR) from the generator to the switchyard and out to the surrounding grid, helping to control the grid voltage decrease. If the switchyard voltage goes low enough, the increased generator field current could result in generator field overheating. Over-excitation protective circuitry is generally employed to prevent this from occurring. This protective circuitry may trip the generator to prevent equipment damage.

Under-voltage protection is provided for the nuclear power plant safety buses, and may be provided on nonsafety buses and at individual pieces of equipment. It is also used in some pressurized water reactor designs on reactor coolant pumps (RCPs) as an anticipatory loss of RCP flow signal.

### ***Protective Features of Nuclear Power Plants***

The main generator and main turbine have protective features, similar to fossil generating stations, which protect against equipment damage. In general, the reactor protective features are designed to protect the reactor fuel from damage and to protect the reactor coolant system from over-pressure or over-temperature transients. Some trip features also produce a corresponding trip in other components; for example, a turbine trip typically results in a reactor trip above a low power setpoint.

Generator protective features typically include over-current, ground detection, differential relays (which monitor for electrical fault conditions

within a zone of protection defined by the location of the sensors, typically the main generator and all transformers connected directly to the generator output), electrical faults on the transformers connected to the generator, loss of the generator field, and a turbine trip. Turbine protective features typically include over-speed (usually set at 1980 rpm or 66 Hz), low bearing oil pressure, high bearing vibration, degraded condenser vacuum, thrust bearing failure, or generator trip. Reactor protective features typically include trips for over-power, abnormal pressure in the reactor coolant system, low reactor coolant system flow, low level in the steam generators or the reactor vessel, or a trip of the turbine.

### **Considerations on Returning a U.S. Nuclear Power Plant to Power Production After Switchyard Voltage Is Restored**

The following are examples of the types of activities that must be completed before returning a nuclear power plant to power production following a loss of switchyard voltage.

- ◆ Switchyard voltage must be normal and stable from an offsite supply. Nuclear power plants are not designed for black-start capability (the ability to start up without external power).
- ◆ Plant buses must be energized from the switchyard and the emergency diesel generators restored to standby mode.
- ◆ Normal plant equipment, such as reactor coolant pumps and circulating water pumps, must be restarted.
- ◆ A reactor trip review report must be completed and approved by plant management, and the cause of the trip must be addressed.
- ◆ All plant technical specifications must be satisfied. Technical specifications are issued to each nuclear power plant as part of their license by the NRC. They dictate equipment which must be operable and process parameters which must be met to allow operation of the reactor. Examples of actions that were required following the events of August 14 include refilling the diesel fuel oil storage tanks, refilling the condensate storage tanks, establishing reactor coolant system forced flow, and cooling the suppression pool to normal operating limits. Surveillance tests must be completed as required by technical specifications (for example, operability of

the low-range neutron detectors must be demonstrated).

- ◆ Systems must be aligned to support the startup.
- ◆ Pressures and temperatures for reactor startup must be established in the reactor coolant system for pressurized water reactors.
- ◆ A reactor criticality calculation must be performed to predict the control rod withdrawals needed to achieve criticality, where the fission chain reaction becomes self-sustaining due to the increased neutron flux. Certain neutron-absorbing fission products increase in concentration following a reactor trip (followed later by a decrease or decay). At pressurized water reactors, the boron concentration in the primary coolant must be adjusted to match the criticality calculation. Near the end of the fuel cycle, the nuclear power plant may not have enough boron adjustment or control rod worth available for restart until the neutron absorbers have decreased significantly (more than 24 hours after the trip).

It may require about a day or more before a nuclear power plant can restart following a normal trip. Plant trips are a significant transient on plant equipment, and some maintenance may be necessary before the plant can restart. When combined with the infrequent event of loss of offsite power, additional recovery actions will be required. Safety systems, such as emergency diesel generators and safety-related decay heat removal systems, must be restored to normal lineups. These additional actions would extend the time necessary to restart a nuclear plant from this type of event.

### **Summary of U.S. Nuclear Power Plant Response to and Safety During the August 14 Outage**

The NWG's review has not identified any activity or equipment issues at nuclear power plants that caused the transient on August 14, 2003. Nine nuclear power plants tripped within about 60 seconds as a result of the grid disturbance. Additionally, many nuclear power plants experienced a transient due to this grid disturbance.

#### ***Nuclear Power Plants That Tripped***

The trips at nine nuclear power plants resulted from the plant responses to the grid disturbances. Following the initial grid disturbances, voltages in the plant switchyard fluctuated and reactive

power flows fluctuated. As the voltage regulators on the main generators attempted to compensate, equipment limits were exceeded and protective trips resulted. This happened at Fermi 2 and Oyster Creek. Fermi 2 tripped on a generator field protection trip. Oyster Creek tripped due to a generator trip on high ratio of voltage relative to the electrical frequency.

Also, as the balance between electrical generation and electrical load on the grid was disturbed, the electrical frequency began to fluctuate. In some cases the electrical frequency dropped low enough to actuate protective features. This happened at Indian Point 2, Indian Point 3, and Perry. Perry tripped due to a generator under-frequency trip signal. Indian Point 2 and Indian Point 3 tripped when the grid frequency dropped low enough to trip reactor coolant pumps, which actuated a reactor protective feature.

In other cases, the electrical frequency fluctuated and went higher than normal. Turbine control systems responded in an attempt to control the frequency. Equipment limits were exceeded as a result of the reaction of the turbine control systems to large frequency changes. This led to trips at FitzPatrick, Nine Mile 1, Nine Mile 2, and Ginna. FitzPatrick and Nine Mile 2 tripped on low pressure in the turbine hydraulic control oil system. Nine Mile 1 tripped on turbine light load protection. Ginna tripped due to conditions in the reactor following rapid closure of the turbine control valves in response to high frequency on the grid.

The Perry, Fermi 2, Oyster Creek, and Nine Mile 1 reactors tripped immediately after the generator tripped, although that is not apparent from the times below, because the clocks were not synchronized to the national time standard. The Indian Point 2 and 3, FitzPatrick, Ginna, and Nine Mile 2 reactors tripped before the generators. When the reactor trips first, there is generally a short time delay before the generator output breakers open. The electrical generation decreases rapidly to zero after the reactor trip. Table 7.1 provides the times from the data collected for the reactor trip times, and the time the generator output breakers opened (generator trip), as reported by the ESWG. Additional details on the plants that tripped are given below.

**Fermi 2.** Fermi 2 is located 25 miles northeast of Toledo, Ohio, in southern Michigan on Lake Erie. It was generating about 1,130 megawatts-electric (MWe) before the event. The reactor tripped due to

a turbine trip. The turbine trip was likely the result of multiple generator field protection trips (over-excitation and loss of field) as the Fermi 2 generator responded to a series of rapidly changing transients prior to its loss. This is consistent with data that shows large swings of the Fermi 2 generator MVARs prior to its trip.

Offsite power was subsequently lost to the plant auxiliary buses. The safety buses were de-energized and automatically reenergized from the emergency diesel generators. The operators tripped one emergency diesel generator that was paralleled to the grid for testing, after which it automatically loaded. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 16:22 EDT due to the loss of offsite power. Offsite power was restored to at least one safety bus at about 01:53 EDT on August 15. The following equipment problems were noted: the Combustion Turbine Generator (the alternate AC power source) failed to start from the control room; however, it was successfully started locally. In addition, the Spent Fuel Pool Cooling System was interrupted for approximately 26 hours and reached a maximum temperature of 130 degrees Fahrenheit (55 degrees Celsius). The main generator was reconnected to the grid at about 01:41 EDT on August 20.

**FitzPatrick.** FitzPatrick is located about 8 miles northeast of Oswego, NY, in northern New York on Lake Ontario. It was generating about 850 MWe before the event. The reactor tripped due to low pressure in the hydraulic system that controls the turbine control valves. Low pressure in this system typically indicates a large load reject, for

**Table 7.1. U.S. Nuclear Plant Trip Times**

Nuclear Plant	Reactor Trip <sup>a</sup>	Generator Trip <sup>b</sup>
Perry . . . . .	16:10:25 EDT	16:10:42 EDT
Fermi 2 . . . . .	16:10:53 EDT	16:10:53 EDT
Oyster Creek . . .	16:10:58 EDT	16:10:57 EDT
Nine Mile 1 . . . .	16:11 EDT	16:11:04 EDT
Indian Point 2 . .	16:11 EDT	16:11:09 EDT
Indian Point 3 . .	16:11 EDT	16:11:23 EDT
FitzPatrick . . . . .	16:11:04 EDT	16:11:32 EDT
Ginna . . . . .	16:11:36 EDT	16:12:17 EDT
Nine Mile 2 . . . .	16:11:48 EDT	16:11:52 EDT

<sup>a</sup>As determined from licensee data (which may not be synchronized to the national time standard).

<sup>b</sup>As reported by the Electrical System Working Group (synchronized to the national time standard).

which a reactor trip is expected. In this case the pressure in the system was low because the control system was rapidly manipulating the turbine control valves to control turbine speed, which was being affected by grid frequency fluctuations.

Immediately preceding the trip, both significant over-voltage and under-voltage grid conditions were experienced. Offsite power was subsequently lost to the plant auxiliary buses. The safety buses were deenergized and automatically reenergized from the emergency diesel generators.

The lowest emergency declaration, an Unusual Event, was declared at about 16:26 EDT due to the loss of offsite power. Decay heat removal systems maintained the cooling function for the reactor fuel. Offsite power was restored to at least one safety bus at about 23:07 EDT on August 14. The main generator was reconnected to the grid at about 06:10 EDT on August 18.

**Ginna.** Ginna is located 20 miles northeast of Rochester, NY, in northern New York on Lake Ontario. It was generating about 487 MWe before the event. The reactor tripped due to Over-Temperature-Delta-Temperature. This trip signal protects the reactor core from exceeding temperature limits. The turbine control valves closed down in response to the changing grid conditions. This caused a temperature and pressure transient in the reactor, resulting in an Over-Temperature-Delta-Temperature trip.

Offsite power was not lost to the plant auxiliary buses. In the operators' judgement, offsite power was not stable, so they conservatively energized the safety buses from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel. Offsite power was not lost, and stabilized about 50 minutes after the reactor trip.

The lowest emergency declaration, an Unusual Event, was declared at about 16:46 EDT due to the degraded offsite power. Offsite power was restored to at least one safety bus at about 21:08 EDT on August 14. The following equipment problems were noted: the digital feedwater control system behaved in an unexpected manner following the trip, resulting in high steam generator levels; there was a loss of RCP seal flow indication, which complicated restarting the pumps; and at least one of the power-operated relief valves experienced minor leakage following proper operation and closure during the transient. Also, one of the motor-driven auxiliary feedwater pumps was

damaged after running with low flow conditions due to an improper valve alignment. The redundant pumps supplied the required water flow.

The NRC issued a Notice of Enforcement Discretion to allow Ginna to perform mode changes and restart the reactor with one auxiliary feedwater (AFW) pump inoperable. Ginna has two AFW pumps, one turbine-driven AFW pump, and two standby AFW pumps, all powered from safety-related buses. The main generator was reconnected to the grid at about 20:38 EDT on August 17.

**Indian Point 2.** Indian Point 2 is located 24 miles north of New York City on the Hudson River. It was generating about 990 MWe before the event. The reactor tripped due to loss of a reactor coolant pump that tripped because the auxiliary bus frequency fluctuations actuated the under-frequency relay, which protects against inadequate coolant flow through the reactor core. This reactor protection signal tripped the reactor, which resulted in turbine and generator trips.

The auxiliary bus experienced the under-frequency due to fluctuating grid conditions. Offsite power was lost to all the plant auxiliary buses. The safety buses were reenergized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 16:25 EDT due to the loss of offsite power for more than 15 minutes. Offsite power was restored to at least one safety bus at about 20:02 EDT on August 14. The following equipment problems were noted: the service water to one of the emergency diesel generators developed a leak; a steam generator atmospheric dump valve did not control steam generator pressure in automatic and had to be shifted to manual; a steam trap associated with the turbine-driven AFW pump failed open, resulting in operators securing the turbine after 2.5 hours; loss of instrument air required operators to take manual control of charging and a letdown isolation occurred; and operators in the field could not use radios. The main generator was reconnected to the grid at about 12:58 EDT on August 17.

**Indian Point 3.** Indian Point 3 is located 24 miles north of New York City on the Hudson River. It was generating about 1,010 MWe before the event. The reactor tripped due to loss of a reactor coolant pump that tripped because the auxiliary bus

frequency fluctuations actuated the under-frequency relay, which protects against inadequate coolant flow through the reactor core. This reactor protection signal tripped the reactor, which resulted in turbine and generator trips.

The auxiliary bus experienced the under-frequency due to fluctuating grid conditions. Offsite power was lost to all the plant auxiliary buses. The safety buses were reenergized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 16:23 EDT due to the loss of offsite power for more than 15 minutes. Offsite power was restored to at least one safety bus at about 20:12 EDT on August 14. The following equipment problems were noted: a steam generator safety valve lifted below its desired setpoint and was gaged; loss of instrument air, including failure of the diesel backup compressor to start and failure of the backup nitrogen system, resulted in manual control of atmospheric dump valves and AFW pumps needing to be secured to prevent overfeeding the steam generators; a blown fuse in a battery charger resulted in a longer battery discharge; a control rod drive mechanism cable splice failed, and there were high resistance readings on 345-kV breaker-1. These equipment problems required correction prior to start-up, which delayed the startup. The main generator was reconnected to the grid at about 05:03 EDT on August 22.

**Nine Mile 1.** Nine Mile 1 is located 6 miles northeast of Oswego, NY, in northern New York on Lake Ontario. It was generating about 600 MWe before the event. The reactor tripped in response to a turbine trip. The turbine tripped on light load protection (which protects the turbine against a loss of electrical load), when responding to fluctuating grid conditions. The turbine trip caused fast closure of the turbine valves, which, through acceleration relays on the control valves, create a signal to trip the reactor. After a time delay of 10 seconds, the generator tripped on reverse power.

The safety buses were automatically deenergized due to low voltage and automatically reenergized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 16:33 EDT due to the

degraded offsite power. Offsite power was restored to at least one safety bus at about 23:39 EDT on August 14. The following additional equipment problems were noted: a feedwater block valve failed “as is” on the loss of voltage, resulting in a high reactor vessel level; fuses blew in fire circuits, causing control room ventilation isolation and fire panel alarms; and operators were delayed in placing shutdown cooling in service for several hours due to lack of procedure guidance to address particular plant conditions encountered during the shutdown. The main generator was reconnected to the grid at about 02:08 EDT on August 18.

**Nine Mile 2.** Nine Mile 2 is located 6 miles northeast of Oswego, NY, in northern New York on Lake Ontario. It was generating about 1,193 MWe before the event. The reactor scrambled due to the actuation of pressure switches which detected low pressure in the hydraulic system that controls the turbine control valves. Low pressure in this system typically indicates a large load reject, for which a reactor trip is expected. In this case the pressure in the system was low because the control system was rapidly manipulating the turbine control valves to control turbine speed, which was being affected by grid frequency fluctuations.

After the reactor tripped, several reactor level control valves did not reposition, and with the main feedwater system continuing to operate, a high water level in the reactor caused a turbine trip, which caused a generator trip. Offsite power was degraded but available to the plant auxiliary buses. The offsite power dropped below the normal voltage levels, which resulted in the safety buses being automatically energized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel.

The lowest emergency declaration, an Unusual Event, was declared at about 17:00 EDT due to the loss of offsite power to the safety buses for more than 15 minutes. Offsite power was restored to at least one safety bus at about 01:33 EDT on August 15. The following additional equipment problem was noted: a tap changer on one of the offsite power transformers failed, complicating the restoration of one division of offsite power. The main generator was reconnected to the grid at about 19:34 EDT on August 17.

**Oyster Creek.** Oyster Creek is located 9 miles south of Toms River, NJ, near the Atlantic Ocean. It was generating about 629 MWe before the event.

The reactor tripped due to a turbine trip. The turbine trip was the result of a generator trip due to actuation of a high Volts/Hz protective trip. The Volts/Hz trip is a generator/transformer protective feature. The plant safety and auxiliary buses transferred from the main generator supply to the offsite power supply following the plant trip. Other than the plant transient, no equipment or performance problems were determined to be directly related to the grid problems.

Post-trip the operators did not get the mode switch to shutdown before main steam header pressure reached its isolation setpoint. The resulting MSIV closure complicated the operator's response because the normal steam path to the main condenser was lost. The operators used the isolation condensers for decay heat removal. The plant safety and auxiliary buses remained energized from offsite power for the duration of the event, and the emergency diesel generators were not started. Decay heat removal systems maintained the cooling function for the reactor fuel. The main generator was reconnected to the grid at about 05:02 EDT on August 17.

**Perry.** Perry is located 7 miles northeast of Painesville, OH, in northern Ohio on Lake Erie. It was generating about 1,275 MWe before the event. The reactor tripped due to a turbine control valve fast closure trip signal. The turbine control valve fast closure trip signal was due to a generator under-frequency trip signal that tripped the generator and the turbine and was triggered by grid frequency fluctuations. Plant operators noted voltage fluctuations and spikes on the main transformer, and the Generator Out-of-Step Supervisory relay actuated approximately 30 minutes before the trip. This supervisory relay senses a ground fault on the grid. The purpose is to prevent a remote fault on the grid from causing a generator out-of-step relay to activate, which would result in a generator trip. Approximately 30 seconds prior to the trip operators noted a number of spikes on the generator field volt meter, which subsequently went offscale high. The MVAR and MW meters likewise went offscale high.

The safety buses were deenergized and automatically reenergized from the emergency diesel generators. Decay heat removal systems maintained the cooling function for the reactor fuel. The following equipment problems were noted: a steam bypass valve opened; a reactor water clean-up system pump tripped; the off-gas system isolated, and a keep-fill pump was found to be air-bound,

requiring venting and filling before the residual heat removal system loop A and the low pressure core spray system could be restored to service.

The lowest emergency declaration, an Unusual Event, was declared at about 16:20 EDT due to the loss of offsite power. Offsite power was restored to at least one safety bus at about 18:13 EDT on August 14. The main generator was reconnected to the grid at about 23:15 EDT on August 21. After the plant restarted, a surveillance test indicated a problem with one emergency diesel generator. An NRC special inspection is in progress, reviewing emergency diesel generator performance and the keep-fill system.

### ***Nuclear Power Plants With a Significant Transient***

The electrical disturbance on August 14 had a significant impact on seven plants that continued to remain connected to the grid. For this review, significant impact means that these plants had significant load adjustments that resulted in bypassing steam from the turbine generator, opening of relief valves, or requiring the onsite emergency diesel generators to automatically start due to low voltage.

### ***Nuclear Power Plants With a Non-Significant Transient***

Sixty-four nuclear power plants experienced non-significant transients caused by minor disturbances on the electrical grid. These plants were able to respond to the disturbances through normal control systems. Examples of these transients included changes in load of a few megawatts or changes in frequency of a few-tenths Hz.

### ***Nuclear Power Plants With No Transient***

Twenty-four nuclear power plants experienced no transient and saw essentially no disturbances on the grid, or were shut down at the time of the transient.

## **General Observations Based on the Facts Found During Phase One**

The NWG has found no evidence that the shutdown of U.S. nuclear power plants triggered the outage or inappropriately contributed to its spread (i.e., to an extent beyond the normal tripping of the plants at expected conditions). This review did not identify any activity or equipment issues that appeared to start the transient on August 14, 2003. All nine plants that experienced a reactor trip were responding to grid conditions. The severity

of the transient caused generators, turbines, or reactor systems to reach a protective feature limit and actuate a plant shutdown.

All nine plants tripped in response to those conditions in a manner consistent with the plant designs. All nine plants safely shut down. All safety functions were effectively accomplished, with few problems, and the plants were maintained in a safe shutdown condition until their restart. Fermi 2, Nine Mile 1, Oyster Creek, and Perry tripped on turbine and generator protective features. FitzPatrick, Ginna, Indian Point 2 and 3, and Nine Mile 2 tripped on reactor protective features.

Nine plants used their emergency diesel generators to power their safety-related buses during the power outage. Offsite power was restored to the safety buses after the grid was energized and the plant operators, in consultation with the transmission system operators, decided the grid was stable. Although the Oyster Creek plant tripped, offsite power was never lost to their safety buses and the emergency diesel generators did not start and were not required. Another plant, Davis-Besse, was already shut down but lost power to the safety buses. The emergency diesel generators started and provided power to the safety buses as designed.

For the eight remaining tripped plants and Davis-Besse (which was already shut down prior to the events of August 14), offsite power was restored to at least one safety bus after a period of time ranging from about 2 hours to about 14 hours, with an average time of about 7 hours. Although Ginna did not lose offsite power, the operators judged offsite power to be unstable and realigned the safety buses to the emergency diesel generators. The second phase of the Power System Outage Task Force will consider the implications of this in developing recommendations for future improvements.

The licensees' return to power operation follows a deliberate process controlled by plant procedures and NRC regulations. Ginna, Indian Point 2, Nine Mile 2, and Oyster Creek resumed electrical generation on August 17. FitzPatrick and Nine Mile 1 resumed electrical generation on August 18. Fermi 2 resumed electrical generation on August 20. Perry resumed electrical generation on August 21. Indian Point 3 resumed electrical generation on August 22. Indian Point 3 had equipment issues (failed splices in the control rod drive mechanism power system) that required repair prior to restart.

Ginna submitted a special request for enforcement discretion from the NRC to permit mode changes and restart with an inoperable auxiliary feedwater pump. The NRC granted the request for enforcement discretion.

## Findings of the Canadian Nuclear Working Group

### Summary

On the afternoon of August 14, 2003, southern Ontario, along with the northeastern United States, experienced a widespread electrical power system outage. Eleven nuclear power plants in Ontario operating at high power levels at the time of the event either automatically shut down as a result of the grid disturbance or automatically reduced power while waiting for the grid to be reestablished. In addition, the Point Lepreau Nuclear Generating Station in New Brunswick was forced to reduce electricity production for a short period.

The Canadian NWG was mandated to: review the sequence of events for each Canadian nuclear plant; determine whether any events caused or contributed to the power system outage; evaluate any potential safety issues arising as a result of the event; evaluate the effect on safety and the reliability of the grid of design features, operating procedures, and regulatory requirements at Canadian nuclear power plants; and assess the impact of associated regulator performance and regulatory decisions.

In Ontario, 11 nuclear units were operating and delivering power to the grid at the time of the grid disturbance: 4 at Bruce B, 4 at Darlington, and 3 at Pickering B. Of the 11 reactors, 7 shut down as a result of the event (1 at Bruce B, 3 at Darlington, and 3 at Pickering B). Four reactors (3 at Bruce B and 1 at Darlington) disconnected safely from the grid but were able to avoid shutting down and were available to supply power to the Ontario grid as soon as reconnection was enabled by Ontario's Independent Market Operator (IMO).

New Brunswick Power's Point Lepreau Generating Station responded to the loss of grid event by cutting power to 460 MW, returning to fully stable conditions at 16:35 EDT, within 25 minutes of the event. Hydro Québec's (HQ) grid was not affected by the power system outage, and HQ's Gentilly-2 nuclear station continued to operate normally.

Having reviewed the operating data for each plant and the responses of the power stations and their staff to the event, the Canadian NWG concludes the following:

- ◆ None of the reactor operators had any advanced warning of impending collapse of the grid.
  - Trend data obtained indicate stable conditions until a few minutes before the event.
  - There were no prior warnings from Ontario's IMO.
- ◆ Canadian nuclear power plants did not trigger the power system outage or contribute to its spread. Rather they responded, as anticipated, in order to protect equipment and systems from the grid disturbances. Plant data confirm the following.
  - At Bruce B and Pickering B, frequency and/or voltage fluctuations on the grid resulted in the automatic disconnection of generators from the grid. For those units that were successful in maintaining the unit generators operational, reactor power was automatically reduced.
  - At Darlington, load swing on the grid led to the automatic reduction in power of the four reactors. The generators were, in turn, automatically disconnected from the grid.
  - Three reactors at Bruce B and one at Darlington were returned to 60% power. These reactors were available to deliver power to the grid on the instructions of the IMO.
  - Three units at Darlington were placed in a zero-power hot state, and four units at Pickering B and one unit at Bruce B were placed in a guaranteed shutdown state.
- ◆ There were no risks to health and safety of workers or the public as a result of the shutdown of the reactors.
  - Turbine, generator, and reactor automatic safety systems worked as designed to respond to the loss of grid.
  - Station operating staff and management followed approved Operating Policies & Principles (OP&Ps) in responding to the loss of grid. At all times, operators and shift supervisors made appropriately conservative decisions in favor of protecting health and safety.

The Canadian NWG commends the staff of Ontario Power Generation and Bruce Power for their response to the power system outage. At all

times, staff acted in accordance with established OP&Ps, and took an appropriately conservative approach to decisions.

During the course of its review, the NWG also identified the following secondary issues:

- ◆ Equipment problems and design limitations at Pickering B resulted in a temporary reduction in the effectiveness of some of the multiple safety barriers, although the equipment failure was within the unavailability targets found in the OP&Ps approved by the CNSC as part of Ontario Power Generation's licence.
- ◆ Existing OP&Ps place constraints on the use of adjuster rods to respond to events involving rapid reductions in reactor power. While greater flexibility with respect to use of adjuster rods would not have prevented the shutdown, some units, particularly those at Darlington, might have been able to return to service less than 1 hour after the initiating event.
- ◆ Off-site power was unavailable for varying periods of time, from approximately 3 hours at Bruce B to approximately 9 hours at Pickering A. Despite the high priority assigned by the IMO to restoring power to the nuclear stations, the stations had some difficulty in obtaining timely information about the status of grid recovery and the restoration of Class IV power. This information is important for Ontario Power Generation's and Bruce Power's response strategy.
- ◆ Required regulatory approvals from CNSC staff were obtained quickly and did not delay the restart of the units; however, CNSC staff was unable to immediately activate the CNSC's Emergency Operation Centre because of loss of power to the CNSC's head office building. CNSC staff, therefore, established communications with licensees and the U.S. NRC from other locations.

## Introduction

The primary focus of the Canadian NWG during Phase I was to address nuclear power plant response relevant to the power outage of August 14, 2003. Data were collected from each power plant and analyzed in order to determine: the cause of the power outage; whether any activities at these plants caused or contributed to the power outage; and whether there were any significant safety issues. In order to obtain reliable and comparable information and data from each nuclear

power plant, a questionnaire was developed to help pinpoint how each nuclear power plant responded to the August 14 grid transients. Where appropriate, additional information was obtained from the ESWG and SWG.

The operating data from each plant were compared against the plant design specifications to determine whether the plants responded as expected. Based on initial plant responses to the questionnaire, supplemental questions were developed, as required, to further clarify outstanding matters. Supplementary information on the design features of Ontario's nuclear power plants was also provided by Ontario Power Generation and Bruce Power. The Canadian NWG also consulted a number of subject area specialists, including CNSC staff, to validate the responses to the questionnaire and to ensure consistency in their interpretation.

### **Typical Design, Operational, and Protective Features of CANDU Nuclear Power Plants**

There are 22 CANDU nuclear power reactors in Canada—20 located in Ontario at 5 multi-unit stations (Pickering A and Pickering B located in Pickering, Darlington located in the Municipality of Clarington, and Bruce A and Bruce B located near Kincardine). There are also single-unit CANDU stations at Bécancour, Québec (Gentilly-2), and Point Lepreau, New Brunswick.

In contrast to the pressurized water reactors used in the United States, which use enriched uranium fuel and a light water coolant-moderator, all housed in a single, large pressure vessel, a CANDU reactor uses fuel fabricated from natural uranium, with heavy water as the coolant and moderator. The fuel and pressurized heavy water coolant are contained in 380 to 480 pressure tubes housed in a calandria containing the heavy water moderator under low pressure. Heat generated by the fuel is removed by heavy water coolant that flows through the pressure tubes and is then circulated to the boilers to produce steam from demineralized water.

While the use of natural uranium fuel offers important benefits from the perspectives of safeguards and operating economics, one drawback is that it restricts the ability of a CANDU reactor to recover from a large power reduction. In particular, the lower reactivity of natural uranium fuel means that CANDU reactors are designed with a

small number of control rods (called “adjuster rods”) that are only capable of accommodating power reductions to 60%. The consequence of a larger power reduction is that the reactor will “poison out” and cannot be made critical for up to 2 days following a power reduction. By comparison, the use of enriched fuel enables a typical pressurized water reactor to operate with a large number of control rods that can be withdrawn to accommodate power reductions to zero power.

A unique feature of some CANDU plants—namely, Bruce B and Darlington—is a capability to maintain the reactor at 60% full power if the generator becomes disconnected from the grid and to maintain this “readiness” condition if necessary for days. Once reconnected to the grid, the unit can be loaded to 60% full power within several minutes and can achieve full power within 24 hours.

As with other nuclear reactors, CANDU reactors normally operate continuously at full power except when shut down for maintenance and inspections. As such, while they provide a stable source of baseload power generation, they cannot provide significant additional power in response to sudden increases in demand. CANDU power plants are not designed for black-start operation; that is, they are not designed to start up in the absence of power from the grid.

### ***Electrical Distribution Systems***

The electrical distribution systems at nuclear power plants are designed to satisfy the high safety and reliability requirements for nuclear systems. This is achieved through flexible bus arrangements, high capacity standby power generation, and ample redundancy in equipment.

Where continuous power is required, power is supplied either from batteries (for continuous DC power, Class I) or via inverters (for continuous AC power, Class II). AC supply for safety-related equipment, which can withstand short interruption (on the order of 5 minutes), is provided by Class III power. Class III power is nominally supplied through Class IV; when Class IV becomes unavailable, standby generators are started automatically, and the safety-related loads are picked up within 5 minutes of the loss of Class IV power.

The Class IV power is an AC supply to reactor equipment and systems that can withstand longer interruptions in power. Class IV power can be supplied either from the generator through a

transformer or from the grid by another transformer. Class IV power is not required for reactors to shut down safely.

In addition to the four classes of power described above, there is an additional source of power known as the Emergency Power System (EPS). EPS is a separate power system consisting of its own on-site power generation and AC and DC distribution systems whose normal supply is from the Class III power system. The purpose of the EPS system is to provide power to selected safety-related loads following common mode incidents, such as seismic events.

### ***Protective Features of CANDU Nuclear Power Plants***

CANDU reactors typically have two separate, independent and diverse systems to shut down the reactor in the event of an accident or transients in the grid. Shutdown System 1 (SDS1) consists of a large number of cadmium rods that drop into the core to decrease the power level by absorbing neutrons. Shutdown System 2 (SDS2) consists of high-pressure injection of gadolinium nitrate into the low-pressure moderator to decrease the power level by absorbing neutrons. Although Pickering A does not have a fully independent SDS2, it does have a second shutdown mechanism, namely, the fast drain of the moderator out of the calandria; removal of the moderator significantly reduces the rate of nuclear fission, which reduces reactor power. Also, additional trip circuits and shutoff rods have recently been added to Pickering A Unit 4 (Shutdown System Enhancement, or SDS-E). Both SDS1 and SDS2 are capable of reducing reactor power from 100% to about 2% within a few seconds of trip initiation.

### ***Fuel Heat Removal Features of CANDU Nuclear Power Plants***

Following the loss of Class IV power and shutdown of the reactor through action of SDS1 and/or SDS2, significant heat will continue to be generated in the reactor fuel from the decay of fission products. The CANDU design philosophy is to provide defense in depth in the heat removal systems.

Immediately following the trip and prior to restoration of Class III power, heat will be removed from the reactor core by natural circulation of coolant through the Heat Transport System main circuit following rundown of the main Heat Transport pumps (first by thermosyphoning and later by intermittent buoyancy induced flow). Heat will be

rejected from the secondary side of the steam generators through the atmospheric steam discharge valves. This mode of operation can be sustained for many days with additional feedwater supplied to the steam generators via the Class III powered auxiliary steam generator feed pump(s).

In the event that the auxiliary feedwater system becomes unavailable, there are two alternate EPS powered water supplies to steam generators, namely, the Steam Generator Emergency Coolant System and the Emergency Service Water System. Finally, a separate and independent means of cooling the fuel is by forced circulation by means of the Class III powered shutdown cooling system; heat removal to the shutdown cooling heat exchangers is by means of the Class III powered components of the Service Water System.

## **CANDU Reactor Response to Loss-of-Grid Event**

### ***Response to Loss of Grid***

In the event of disconnection from the grid, power to safely shut down the reactor and maintain essential systems will be supplied from batteries and standby generators. The specific response of a reactor to disconnection from the grid will depend on the reactor design and the condition of the unit at the time of the event.

**60% Reactor Power:** All CANDU reactors are designed to operate at 60% of full power following the loss of off-site power. They can operate at this level as long as demineralized water is available for the boilers. At Darlington and Bruce B, steam can be diverted to the condensers and recirculated to the boilers. At Pickering A and Pickering B, excess steam is vented to the atmosphere, thereby limiting the operating time to the available inventory of demineralized water.

**0% Reactor Power, Hot:** The successful transition from 100% to 60% power depends on several systems responding properly, and continued operation is not guaranteed. The reactor may shut down automatically through the operation of the process control systems or through the action of either of the shutdown systems.

Should a reactor shutdown occur following a load rejection, both Class IV power supplies (from the generator and the grid) to that unit will become unavailable. The main Heat Transport pumps will trip, leading to a loss of forced circulation of coolant through the core. Decay heat will be continuously removed through natural circulation

(thermosyphoning) to the boilers, and steam produced in the boilers will be exhausted to the atmosphere via atmospheric steam discharge valves. The Heat Transport System will be maintained at around 250 to 265 degrees Celsius during thermosyphoning. Standby generators will start automatically and restore Class III power to key safety-related systems. Forced circulation in the Heat Transport System will be restored once either Class III or Class IV power is available.

When shut down, the natural decay of fission products will lead to the temporary buildup of neutron absorbing elements in the fuel. If the reactor is not quickly restarted to reverse this natural process, it will “poison-out.” Once poisoned-out, the reactor cannot return to operation until the fission products have further decayed, a process which typically takes up to 2 days.

**Overpoisoned Guaranteed Shutdown State:** In the event that certain problems are identified when reviewing the state of the reactor after a significant transient, the operating staff will cool down and depressurize the reactor, then place it in an overpoisoned guaranteed shutdown state (GSS) through the dissolution of gadolinium nitrate into the moderator. Maintenance will then be initiated to correct the problem.

#### *Return to Service Following Loss of Grid*

The return to service of a unit following any one of the above responses to a loss-of-grid event is discussed below. It is important to note that the descriptions provided relate to operations on a single unit. At multi-unit stations, the return to service of several units cannot always proceed in parallel, due to constraints on labor availability and the need to focus on critical evolutions, such as taking the reactor from a subcritical to a critical state.

**60% Reactor Power:** In this state, the unit can be resynchronized consistent with system demand, and power can be increased gradually to full power over approximately 24 hours.

**0% Reactor Power, Hot:** In this state, after approximately 2 days for the poison-out, the turbine can be run up and the unit synchronized. The reactor may shut down automatically through the operation of the process control systems or through the action of either of the shutdown systems. Thereafter, power can be increased to high power over the next day. This restart timeline does not include the time required for any repairs or maintenance that might have been necessary during the outage.

**Overpoisoned Guaranteed Shutdown State:** Placing the reactor in a GSS after it has been shut down requires approximately 2 days. Once the condition that required entry to the GSS is rectified, the restart requires removal of the guarantee, removal of the gadolinium nitrate through ion exchange process, heatup of the Heat Transport System, and finally synchronization to the grid. Approximately 4 days are required to complete these restart activities. In total, 6 days from shutdown are required to return a unit to service from the GSS, and this excludes any repairs that might have been required while in the GSS.

### **Summary of Canadian Nuclear Power Plant Response to and Safety During the August 14 Outage**

On the afternoon of August 14, 2003, 15 Canadian nuclear units were operating: 13 in Ontario, 1 in Québec, and 1 in New Brunswick. Of the 13 Ontario reactors that were critical at the time of the event, 11 were operating at or near full power and 2 at low power (Pickering B Unit 7 and Pickering A Unit 4). All 13 of the Ontario reactors disconnected from the grid as a result of the grid disturbance. Seven of the 11 reactors operating at high power shut down, while the remaining 4 operated in a planned manner that enabled them to remain available to reconnect to the grid at the request of Ontario’s IMO. Of the 2 Ontario reactors operating at low power, Pickering A Unit 4 tripped automatically, and Pickering B Unit 7 was tripped manually and shut down. In addition, a transient was experienced at New Brunswick Power’s Point Lepreau Nuclear Generating Station, resulting in a reduction in power. Hydro Québec’s Gentilly-2 nuclear station continued to operate normally as the Hydro Québec grid was not affected by the grid disturbance.

#### *Nuclear Power Plants With Significant Transients*

**Pickering Nuclear Generating Station.** The Pickering Nuclear Generating Station (PNGS) is located in Pickering, Ontario, on the shores of Lake Ontario, 30 kilometers east of Toronto. It houses 8 nuclear reactors, each capable of delivering 515 MW to the grid. Three of the 4 units at Pickering A (Units 1 through 3) have been shut down since late 1997. Unit 4 was restarted earlier this year following a major refurbishment and was in the process of being commissioned at the time of the event. At Pickering B, 3 units were operating at or near 100% prior to the event, and Unit 7 was

being started up following a planned maintenance outage.

*Pickering A.* As part of the commissioning process, Unit 4 at Pickering A was operating at 12% power in preparation for synchronization to the grid. The reactor automatically tripped on SDS1 due to Heat Transport Low Coolant Flow, when the Heat Transport main circulating pumps ran down following the Class IV power loss. The decision was then made to return Unit 4 to the guaranteed shutdown state. Unit 4 was synchronized to the grid on August 20, 2003. Units 1, 2 and 3 were in lay-up mode.

*Pickering B.* The Unit 5 Generator Excitation System transferred to manual control due to large voltage oscillations on the grid at 16:10 EDT and then tripped on Loss of Excitation about 1 second later (prior to grid frequency collapse). In response to the generator trip, Class IV buses transferred to the system transformer and the reactor setback. The grid frequency collapse caused the System Service Transformer to disconnect from the grid, resulting in a total loss of Class IV power. The reactor consequently tripped on the SDS1 Low Gross Flow parameter followed by an SDS2 trip due to Low Core Differential Pressure.

The Unit 6 Generator Excitation System also transferred to manual control at 16:10 EDT due to large voltage oscillations on the grid and the generator remained connected to the grid in manual voltage control. Approximately 65 seconds into the event, the grid under-frequency caused all the Class IV buses to transfer to the Generator Service Transformer. Ten seconds later, the generator separated from the Grid. Five seconds later, the generator tripped on Loss of Excitation, which caused a total loss of Class IV power. The reactor consequently tripped on the SDS1 Low Gross Flow parameter, followed by an SDS2 trip due to Low Core Differential Pressure.

Unit 7 was coming back from a planned maintenance outage and was at 0.9% power at the time of the event. The unit was manually tripped after loss of Class IV power, in accordance with procedures and returned to guaranteed shutdown state.

Unit 8 reactor automatically set back on load rejection. The setback would normally have been terminated at 20% power but continued to 2% power because of the low boiler levels. The unit subsequently tripped on the SDS1 Low Boiler Feedline Pressure parameter due to a power mismatch between the reactor and the turbine.

The following equipment problems were noted. At Pickering, the High Pressure Emergency Coolant Injection System (HPECIS) pumps are designed to operate from a Class IV power supply. As a result of the shutdown of all the operating units, the HPECIS at both Pickering A and Pickering B became unavailable for 5.5 hours. (The operating licenses for Pickering A and Pickering B permit the HPECIS to be unavailable for up to 8 hours annually. This was the first unavailability of the year.) In addition, Emergency High Pressure Service Water System restoration for all Pickering B units was delayed because of low suction pressure supplying the Emergency High Pressure Service Water pumps. Manual operator intervention was required to restore some pumps back to service.

Units were synchronized to the grid as follows: Unit 8 on August 22, Unit 5 on August 23, Unit 6 on August 25, and Unit 7 on August 29.

**Darlington Nuclear Generating Station.** Four reactors are located at the Darlington Nuclear Generation Station, which is on the shores of Lake Ontario in the Municipality of Clarington, 70 kilometers east of Toronto. All four of the reactors are licensed to operate at 100% of full power, and each is capable of delivering approximately 880 MW to the grid.

Unit 1 automatically stepped back to the 60% reactor power state upon load rejection at 16:12 EDT. Approval by the shift supervisor to automatically withdraw the adjuster rods could not be provided due to the brief period of time for the shift supervisor to complete the verification of systems as per procedure. The decreasing steam pressure and turbine frequency then required the reactor to be manually tripped on SDS1, as per procedure for loss of Class IV power. The trip occurred at 16:24 EDT, followed by a manual turbine trip due to under-frequency concerns.

Like Unit 1, Unit 2 automatically stepped back upon load rejection at 16:12 EDT. As with Unit 1, there was insufficient time for the shift supervisor to complete the verification of systems, and faced with decreasing steam pressure and turbine frequency, the decision was made to shut down Unit 2. Due to under-frequency on the main Primary Heat Transport pumps, the turbine was tripped manually which resulted in an SDS1 trip at 16:28 EDT.

Unit 3 experienced a load rejection at 16:12 EDT, and during the stepback Unit 3 was able to sustain operation with steam directed to the condensers.

After system verifications were complete, approval to place the adjuster rods on automatic was obtained in time to recover, at 59% reactor power.

The unit was available to resynchronize to the grid. Unit 4 experienced a load rejection at 16:12 EDT, and required a manual SDS1 trip due to the loss of Class II bus. This was followed by a manual turbine trip.

The following equipment problems were noted: Unit 4 Class II inverter trip on BUS A3 and subsequent loss of critical loads prevented unit recovery. The Unit 0 Emergency Power System BUS B135 power was lost until the Class III power was restored. (A planned battery bank B135 change out was in progress at the time of the blackout.)

Units were synchronized to the grid as follows: Unit 3 at 22:00 EDT on August 14; Unit 2 on August 17, 2003; Unit 1 on August 18, 2003; and Unit 4 on August 18, 2003.

**Bruce Power.** Eight reactors are located at Bruce Power on the eastern shore of Lake Huron between Kincardine and Port Elgin, Ontario. Units 5 through 8 are capable of generating 840 MW each. Presently these reactors are operating at 90% of full power due to license conditions imposed by the CNSC. Units 1 through 4 have been shutdown since December 31, 1997. Units 3 and 4 are in the process of startup.

*Bruce A.* Although these reactors were in guaranteed shutdown state, they were manually tripped, in accordance with operating procedures. SDS1 was manually tripped on Units 3 and 4, as per procedures for a loss of Class IV power event. SDS1 was re-poised on both units when the station power supplies were stabilized. The emergency transfer system functioned as per design, with the Class III standby generators picking up station electrical loads. The recently installed Qualified Diesel Generators received a start signal and were available to pick up emergency loads if necessary.

*Bruce B.* Units 5, 6, 7, and 8 experienced initial generation rejection and accompanying stepback on all four reactor units. All generators separated from the grid on under-frequency at 16:12 EDT. Units 5, 7, and 8 maintained reactor power at 60% of full power and were immediately available for reconnection to the grid.

Although initially surviving the loss of grid event, Unit 6 experienced an SDS1 trip on insufficient Neutron Over Power (NOP) margin. This occurred

while withdrawing Bank 3 of the adjusters in an attempt to offset the xenon transient, resulting in a loss of Class IV power.

The following equipment problems were noted: An adjuster rod on Unit 6 had been identified on August 13, 2003, as not working correctly. Unit 6 experienced a High Pressure Recirculation Water line leak, and the Closed Loop Demineralized Water loop lost inventory to the Emergency Water Supply System.

Units were synchronized to the grid as follows: Unit 8 at 19:14 EDT on August 14, 2003; Unit 5 at 21:04 EDT on August 14; and Unit 7 at 21:14 EDT on August 14, 2003. Unit 6 was resynchronized at 02:03 EDT on August 23, 2003, after maintenance was conducted.

**Point Lepreau Nuclear Generating Station.** The Point Lepreau nuclear station overlooks the Bay of Fundy on the Lepreau Peninsula, 40 kilometers southwest of Saint John, New Brunswick. Point Lepreau is a single-unit CANDU 6, designed for a gross output of 680 MW. It is owned and operated by New Brunswick Power.

Point Lepreau was operating at 91.5% of full power (610 MWe) at the time of the event. When the event occurred, the unit responded to changes in grid frequency as per design. The net impact was a short-term drop in output by 140 MW, with reactor power remaining constant and excess thermal energy being discharged via the unit steam discharge valves. During the 25 seconds of the event, the unit stabilizer operated numerous times to help dampen the turbine generator speed oscillations that were being introduced by the grid frequency changes. Within 25 minutes of the event initiation, the turbine generator was reloaded to 610 MW. Given the nature of the event that occurred, there were no unexpected observations on the New Brunswick Power grid or at Point Lepreau Generating Station throughout the ensuing transient.

### ***Nuclear Power Plants With No Transient***

**Gentilly-2 Nuclear Station.** Hydro Québec owns and operates Gentilly-2 nuclear station, located on the south shore of the St. Lawrence River opposite the city of Trois-Rivières, Québec. Gentilly-2 is capable of delivering approximately 675 MW to Hydro Québec's grid. The Hydro Québec grid was not affected by the power system outage and Gentilly-2 continued to operate normally.

## General Observations Based on the Facts Found During Phase One

Following the review of the data provided by the Canadian nuclear power plants, the Nuclear Working Group concludes the following:

- ◆ None of the reactor operators had any advanced warning of impending collapse of the grid.
- ◆ Canadian nuclear power plants did not trigger the power system outage or contribute to its spread.
- ◆ There were no risks to the health and safety of workers or the public as a result of the concurrent shutdown of several reactors. Automatic safety systems for the turbine generators and reactors worked as designed. (See Table 7.2 for a summary of shutdown events for Canadian nuclear power plants.)

The NWG also identified the following secondary issues:

- ◆ Equipment problems and design limitations at Pickering B resulted in a temporary reduction in the effectiveness of some of the multiple safety barriers, although the equipment failure was within the unavailability targets found in the OP&Ps approved by the CNSC as part of Ontario Power Generation's license.

- ◆ Existing OP&Ps place constraints on the use of adjuster rods to respond to events involving rapid reductions in reactor power. While greater flexibility with respect to use of adjuster rods would not have prevented the shutdown, some units, particularly those at Darlington, might have been able to return to service less than 1 hour after the initiating event.
- ◆ Off-site power was unavailable for varying periods of time, from approximately 3 hours at Bruce B to approximately 9 hours at Pickering A. Despite the high priority assigned by the IMO to restoring power to the nuclear stations, the stations had some difficulty obtaining timely information about the status of grid recovery and the restoration of Class IV power. This information is important for Ontario Power Generation's and Bruce Power's response strategy.
- ◆ Required regulatory approvals from CNSC staff were obtained quickly and did not delay the restart of the units; however, CNSC staff was unable to immediately activate the CNSC's Emergency Operation Centre because of loss of power to the CNSC's head office building. CNSC staff, therefore, established communications with licensees and the U.S. NRC from other locations.

**Table 7.2. Summary of Shutdown Events for Canadian Nuclear Power Plants**

Generating Station	Unit	Operating Status at Time of Event			Response to Event			
		Full Power	Startup	Not Operating	Stepback to 60% Power, Available To Supply Grid	Turbine Trip	Reactor Trip	
							SDS1	SDS2
Pickering NGS	1			√			(a)	
	2			√				
	3			√				
	4		√				√	(b)
	5	√					√	√
	6	√					√	√
	7		√				√	
	8	√					√	
Darlington NGS	1	√				√	√	
	2	√				√	√	
	3	√			√			
	4	√				√	√	
Bruce Nuclear Power Development	1			√				
	2			√				
	3			√			√	
	4			√			√	
	5	√			√			
	6	√					√	
	7	√			√			
	8	√			√			

<sup>a</sup>Pickering A Unit 1 tripped as a result of electrical bus configuration immediately prior to the event which resulted in a temporary loss of Class II power.

<sup>b</sup>Pickering A Unit 4 also tripped on SDS-E.

Notes: Unit 7 at Pickering B was operating at low power, warming up prior to reconnecting to the grid after a maintenance outage. Unit 4 at Pickering A was producing at low power, as part of the reactor's commissioning after extensive refurbishment since being shut down in 1997.