Designing a Reliable Power System: Hydro-Québec's Integrated Approach

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Invited Paper

Hydro-Québec's transmission system is among the most extensive and complex transmission networks in North America. The system's design was improved over the last few years using an optimization process based on acquired experience as well as customers' expectations. Hydro-Québec's transmission system is currently designed in accordance with four major guiding principles based on a successive line of defense concept designed to counter events that are increasingly more severe but also increasingly more rare.

These major guiding principles are a direct reflection of the level of risk that society accepts to tolerate in relation to the costs involved by higher reliability requirements. Québec's specific context, which is characterized by long transmission lines, harsh weather, and customers' heavy reliance on electricity for their heating needs, means that very high security standards must be used in the system design. To obtain a level of reliability on par with that of our neighbors' systems, however, requires more stringent criteria and standards.

This paper will describe the design philosophy of Hydro-Québec's power system, the underlying major guiding principles, and the defense plans designed to ensure its reliability.

Keywords*—*Catastrophic event, defense plan, design criteria, extreme contingencies, power system reliability, special protection system.

I. INTRODUCTION

The basic aim of every electric power system is to transport electricity from the generation centers to the load centers in a reliable and secure manner. The system must be planned, designed, built, and operated such that it remains within certain thermal, voltage, and stability limits under a wide variety of conditions such as continuous variations in load, equipment unavailability and failure, and climatic or other types of conditions.

Several countries recently experienced major system outages. The power outages in Italy in September 2003, in the northeastern United States in August 2003, and in the Philippines in May 2002—to mention only the most recent ones—each time left more than 40 million people in the dark, disrupted social life, and had a major economic impact. Recent history shows that no large-scale power system is exempt from a succession of complex and rare events that can lead to a collapse of a large part of the system or a major outage. In our society where electricity plays a key role, the consequences of such events are always very crucial to a nation.

Deregulation and the opening of markets have now become worldwide trends. The main objective is to introduce competition wherever possible and to reduce prices, on the condition, of course, that service quality is maintained.

As a result, electric power systems, which are being operated increasingly closer to their limits, have become much more complex. Because of this increasing complexity, the risk of outages is now more than ever a preoccupation. Knowing how to deal with this risk is crucial in the planning of large-scale transmission systems.

Hydro-Québec's power system is one of the most extensive and complex in North America. Its main infrastructure, made up of more than 11 000 km of 735-kV lines, largely relies on dynamic shunt compensation, series compensation, and automatic defense plans to maximize its reliability and security. This paper proposes to describe the experience acquired by Hydro-Québec over the last 30 years in the design and operation of this large and complex power system, made up of many transmission technologies interacting with each other. This paper will then focus on how Hydro-Québec designs its power system to ensure a high level of reliability, including a description of its defense plan against extreme contingencies, a description of its defense plan against system separation, and a description of the means used to ensure adequate service after catastrophic events.

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II. HYDRO-QUÉBEC'S TRANSMISSION SYSTEM

Geographic constraints have played a key role in the development of Hydro-Québec's system. The fact that most of its generating facilities are large hydroelectric power plants located more than 1000 km from the main consumption centers led Hydro-Québec to design a very extensive, extra-high-voltage 735-kV transmission system. A harsh climate and the fact that electricity accounts for over 40% of Québec's overall energy consumption make Hydro-Québec's customers heavily reliant on electricity. In addition, the high reliance on electricity as the main source of heating is specific to Québec and implies that extended power outages, which always have a major economic impact, may also, in Québec's case, put the public's safety at risk.

Hydro-Québec's system has a number of characteristics that make stability and voltage control critical issues in the design of its transmission system. Among the most important of these characteristics are:

- the isolation of Hydro-Québec system's (no synchronous link with neighboring systems);
- the large distances between generation and load centers and the concentration of generation at large hydroelectric sites (85% of total generation is concentrated in three large, remote hydroelectric complexes);
- the use of a 735-kV transmission system that is very extensive (more than 11 000 km of 735-kV lines) but has a relatively limited number of lines located in two main corridors.

Hydro-Québec's power system is thus a complex, extensive network which requires the use of most technologies specific to large-scale transmission systems. Some of the major components on which the reliability of Hydro-Québec's system is based include extra-high-voltage 735-kV dc interconnections, dynamic shunt compensation, series compensation, static excitation systems equipped with power stabilizers, and special protection systems.

The system as planned for 2004 is shown in Fig. 1. It includes the generation of about 37 000 MW on a system consisting of eleven 735-kV lines divided into two main corridors each about 1000 km in length. The first major transmission corridor extends northwest up to the James Bay hydroelectric complex (15 000 MW), while the second corridor extends northeast up to Churchill-Falls and integrates about 14 000 MW of generation. To complete this base infrastructure, there are also thirty-one 735-kV substations, 11 200 MVAR in series compensation, one 1200-km ± 450-kV dc line, dynamic shunt compensation consisting of 11 static compensators and nine synchronous compensators, and, finally, about 3900 MW of dc interconnections with neighboring systems. The interconnections which link Hydro-Québec's transmission system with its neighbors are either dc or ac. In either case, Hydro-Québec's system is never synchronized with neighboring systems either in Canada (Ontario and New Brunswick) or in the United States (New York State and New England). The ac ties therefore require the islanding of generating stations or loads on neighboring systems. The maximum export and import capacities are 6900 and 4325 MW, respectively.

III. SOURCES OF VULNERABILITY

The special characteristics of Hydro-Québec's system-long 735-kV transmission lines, large generating facilities, and no synchronous links with neighboring systems—mean that a large diversity of power system phenomena are likely to occur after an event. Thus, depending on the triggering event, Hydro-Québec's system may be faced with:

- transient instability;
- dynamic instability (interregional oscillations at 0.5 Hz);
- voltage instability;
- frequency instability (over- or underfrequency).

The different events that may affect the electrical or mechanical integrity of a transmission system are due to various causes, which fall into three major categories:

- natural causes such as lightning, storms, cold, ice, forest fires, and geomagnetic storms;
- outages or equipment or protection system failure, with either immediate or latent consequences that may only affect the system when used;
- the human factor (e.g., operating errors, vandalism, and design flaws).

Table 1 shows the probability of occurrence of typical events on Hydro-Québec's 735-kV transmission system. These data were obtained based on an observation of the power system over a 20-year period.

Two major events in particular put into question the way in which the power system is designed: the major power outage of 1982 and the ice storm of 1998.

Three major power outages occurred in the 1980s: in December 1982, April 1988, and March 1989. The 1982 power outage, however, was the turning point in terms of system reliability. The outage, which was triggered by the explosion of a current transformer at Lévis substation and the tripping of several 735-kV lines, occurred in the winter, during near-peak demand. Since most of the generating stations had to be started up again, the system restoration time was fairly long. Following this power outage, Hydro-Québec noted significant changes in the expectations of its customers, who were increasingly dependent on electrical power, as well as a substantial increase in the economic and social costs related to service interruptions.

The last two major power outages (in 1988 and 1989) confirmed that customers were dissatisfied with the quality of service and catalyzed the utility's efforts to establish new design requirements and an enhancement program focusing on improving the system's reliability [1].

The 1998 ice storm, for its part, affected 40% of Hydro-Québec's customers, some of whom were without power for up to a month. The ice storm stood out in terms of its intensity, scope and duration, which made it an exceptional event. Thus, over a five-day period (5–9 January 1998), three consecutive freezing-rain episodes subjected the entire power system in the southwestern part of the province of Québec

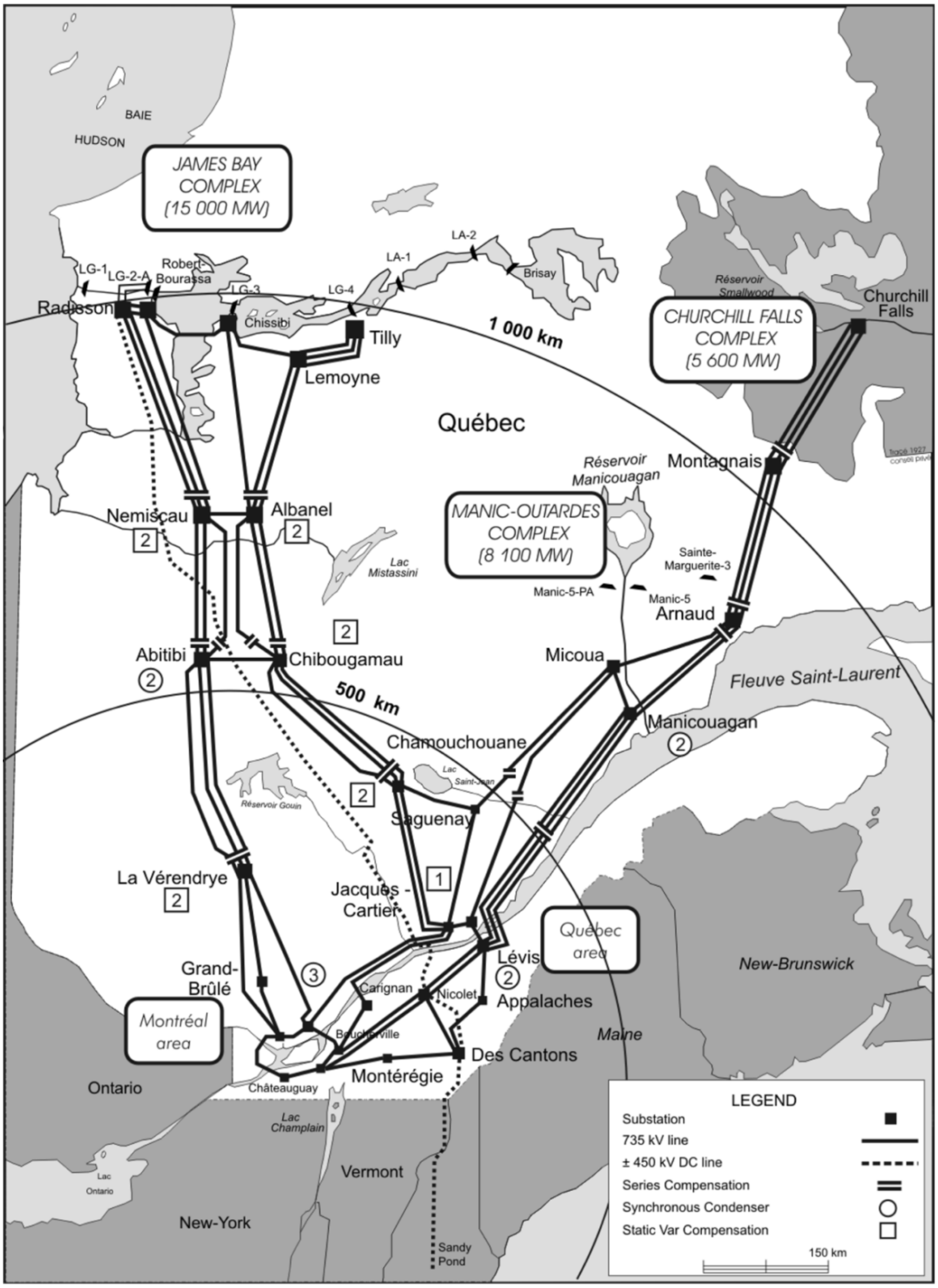

Fig. 1. Hydro-Québec's 735-kV transmission system.

Table 1
Annual Occurrence of Faults on Hydro-Québec's Power System

Fault or event on Hydro-Québec's 735-kV power system	Annual occurrence
Phase-to-ground fault	38.3
Phase-to-phase fault	3.64
Three-phase fault	0.48
Loss of two 735-kV lines	1.29
Loss of more than two 735-kv lines	0.65
Loss of bipolar dc line	0.87
Ac-dc common mode	0.125

to climatic conditions never before encountered in this area by depositing more than 75 mm of ice in some parts.

At the height of the ice storm, about 120 transmission lines with voltage levels ranging from 44 to 735 kV and more than 3100 transmission towers were damaged by interrupting power to 1.4 million customers. It should be noted, however, that the stability of the system was never at risk and the problem pertained to the mechanical integrity of part of the system.

These two major incidents indicate that events which can affect power system reliability fall into two broad categories:

- events that put the power system's electrical integrity at risk;
- events that threaten the system's mechanical integrity (damage to major infrastructures such as transmission lines).

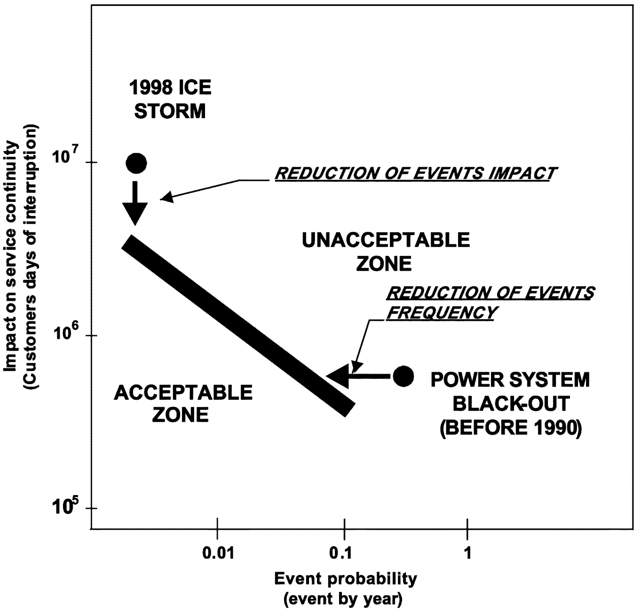

Fig. 2. Risk graph.

These two categories do not require the same solutions even though the outcome was the same, i.e., interruption in service to a fairly large percentage of customers over a relatively long period.

The major events which occurred on the power system show the large variety of possible phenomena (i.e., transient instability, voltage instability, effects from geomagnetic storms) and their complex implications in terms of both design and system operation. Each major event was studied in detail and led to a multitude of projects being carried out to prevent a recurrence and ensure that service would be quickly restored should the event ever reoccur.

IV. THE DESIGN PHILOSOPHY OF HYDRO-QUÉBEC'S POWER SYSTEM

The design philosophy underlying Hydro-Québec's power system is the result of experience acquired by the company over the last 30 years in the design and operation of a large-scale electrical power system. The objective is to ensure that the transmission system design is sufficiently flexible and robust to be able to meet the needs of customers reliably, at the least possible cost, and despite variations in operating conditions and equipment faults and unavailability. The design of the transmission system has been improved in recent years thanks to an optimization process based on acquired experience and customers' expectations. The system's current design is based on four major guiding principles, which are used to set the risk/cost ratio associated with the design of a large-scale power system. These principles are thus a direct reflection of the level of risk that the society accept to tolerate in relation to the costs associated with increased reliability requirements.

Fig. 2 is a risk graph that compares the probability of events occurring against their impact on the power system in terms of service continuity (average interruption duration index). This figure indicates the level of risk currently tolerated by customers and shows that the less the likelihood of an event occurring, the greater the level of tolerance toward interruptions in service.

The reference value (black bar) divides the probability/impact graph into two separate areas:

- an *unacceptable area*, which requires the implementation of measures, even if costly, aimed at reducing the frequency of the events or the impact of events on customers.
- an *acceptable area*, where preventive measures do not need to be implemented or must stem from technical and economic studies to demonstrate increased reliability.

The figure contains two points that respectively represent the impact of the 1998 ice storm (10 million customer-days of interruption with a probability of occurrence of once every 300 years) and the status of the power system prior to 1990 regarding the outages caused by exceptional events (average interruption of 600 000 customer-days at a frequency of once every three years).

The outage situation resulting from exceptional electrical events was corrected through a vast program aimed at improving power system reliability in the early 1990s at a cost of \$1.3 billion.[1] With respect to the reduction of impacts caused by climatic events such as the 1998 ice storm, Hydro-Québec has already implemented projects aimed at improving the security of the supply in the affected area and intends, in the years to come, to make corrections to the power system as a whole. Over \$1 billion has been earmarked for the latter objective.

As a result of Québec's specific context—geographically vast transmission system, harsh climate, and heavy reliance of customers on electricity for their heating needs—the power system design must use very high security standards in order to obtain a reliability on par with that of neighboring systems.

V. DESIGN PRINCIPLES UNDERLYING HYDRO-QUÉBEC'S TRANSMISSION SYSTEM

The great diversity, complexity, and speed of phenomena which must be taken into account in the design of Hydro-Québec's transmission system explains why system reliability depends almost exclusively on the implementation of automatic means based on a principle of successive lines of defense. This concept, which is shown in Fig. 3, allows events that are increasingly more severe and also increasingly more rare to be covered and is directly derived from the four main guiding principles used as a basis for the design of Hydro-Québec's entire power system.

Principle No. 1: Service continuity must be assured following events most likely to occur on the power system.

The system must be designed to support a set of conceptual contingencies without any service interruption or the use of any special protection systems (SPSs). Therefore, one can only count on the equipment and the power system's

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[1] Throughout this paper, dollar figures are Canadian dollars.

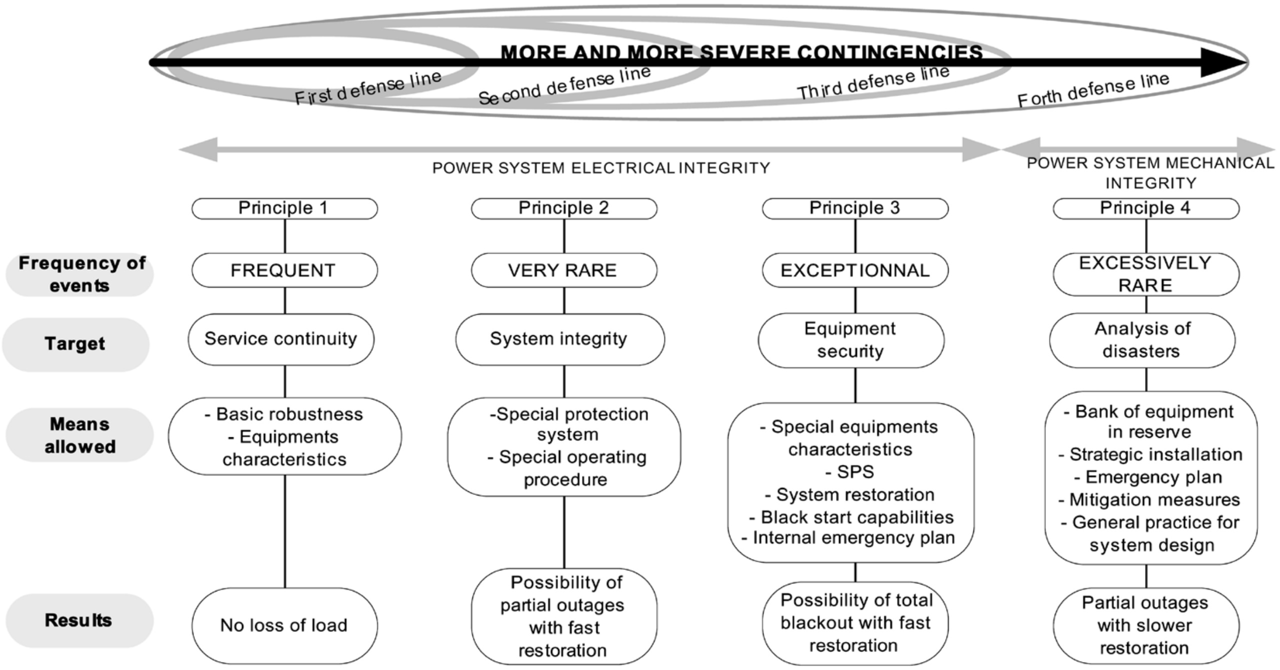

Fig. 3. Hydro-Québec's concept of successive line of defense.

intrinsic robustness to ensure the stability and adequate behavior of the power system. System stability must be maintained during and after the most severe of these contingencies and applied to the transmission system under the following conditions.

- With all equipment in service and carrying power corresponding to the maximum peak power less the spinning reserve.
- After the loss of any critical transmission circuit, generator, transformer, HVdc pole, series, or shunt compensator, assuming that generation and power flows are adjusted between outages by the use of the operating reserve.
- With all equipment in service and carrying power corresponding to the maximum peak power plus 4000 MW to cover exceptionally cold conditions. For this particular condition, the interruptible load, imported electricity through interconnections, and the startup of certain thermal plants located near load centers are used.

Conceptual contingencies (see Table 2) are events with the greatest probability of occurrence and which meet NPCC requirements.

Table 2
Conceptual Contingencies Used in the Design of Hydro-Québec's Bulk Power System

A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with normal fault clearing.
Simultaneous permanent phase-to-earth faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower with normal fault clearing.
A permanent phase-to-earth fault with delayed fault clearing on any transmission circuit, transformer, or bus section.
The loss of any element without a fault.
A permanent phase-to-earth fault on a circuit breaker, with normal fault clearing.
The simultaneous permanent loss of both poles of a DC bipolar facility.

Principle No. 2: Hydro-Québec's power system must include ways of avoiding system-wide power failures under extreme contingencies.

The specific structure of its power system and exposure to a harsh climate have led Hydro-Québec to require a higher level of reliability in order to supply power to customers who are highly dependent on electricity. Hydro-Québec found it essential to minimize the frequency of occurrence and extent of failures resulting from more serious but less common contingencies than conceptual contingencies. The philosophy adopted by Hydro-Québec for the protection against extreme contingencies is that a general power failure must not be the consequence of a situation that could reasonably have been avoided. The objective is therefore to preserve the system's integrity by using automatic measures (special protection systems) that are simple, reliable, and safe for the system and provide the most extensive coverage possible against extreme contingencies. All SPSs used to protect Hydro-Québec's power system during extreme contingencies are grouped under the heading *Defense Plan Against Extreme Contingencies*.

Table 3 lists the various extreme contingencies used for power system planning and the level of performance required for each one. The required performance level depends on the probability of occurrence of each contingency and takes into account the characteristics of Hydro-Québec system's and operating conditions.

It is important to note that for some of these contingencies service continuity is required but the use of SPSs is allowed. These contingencies are thus considered similar, in terms of required performance, to conceptual contingencies. In these cases, SPS actions are limited and load shedding is tolerated

Table 3
Performance Requirements for Extreme Contingencies

EXTREME CONTINGENCIES	PERFORMANCE REQUIREMENTS
Single line to ground fault (SLGF) with loss of two series or two parallel 735-kV lines	A
SLGF with loss of one or two parallel 735-kV lines and bypass of all series capacitors on the remaining parallel lines in the same corridor	B
Ac-dc event: Loss of a bipolar dc line caused by an SLGF with loss of a 735-kV line	B
SLGF with loss of all lines in a corridor in	
▪ The Churchill-Manic section	B
▪ Elsewhere	C
Loss of all 735-kV lines originating from a substation	C
Loss of all generation units at a station	C
Loss of a major load centre	C
Three-phase fault with delayed clearing	C
Unintended operation of an SPS for an event or condition for which it was not designed	B

Performance requirements:
A: Stable, service continuity (except for voltage instability phenomena); SPS with limited action.
B: Stable at peak load; all SPS allowed.
C: Stable at least at 75% power transfer level; all SPS allowed.

only for voltage instability phenomena. The defense plan against extreme contingencies is described in Section VI.

Principle No. 3: Strategic equipment must not sustain any damage in the event of a general outage to ensure that system restoration is always an option.

The two first design principles presented above represent actions aimed at preserving the integrity of the transmission system. More extreme and unexpected events may lead to system instability, though this is highly unlikely given the measures that are in place. However, should this occur, the impact on the installations could be disastrous if no additional precautions are planned. In fact, under such circumstances, our vast transmission system at very high voltage levels would be subjected to high load shedding overvoltages which could put substation equipment in jeopardy. This is why Hydro-Québec has deployed special measures, grouped under the heading *Defense Plan Against System Separation*, dealing only with the safety of equipment in relation to electrical constraints. Section VII describes this defense plan.

Principle No. 4: Hydro-Québec's transmission system must be designed so as to allow the system to be restored within a reasonable period after a catastrophic event.

Catastrophic events put the system's structural robustness to the test by affecting its capacity to supply the load. The previous design principles, which are based on a deterministic approach, aim at covering the consequences of localized events and ensure that the load can always be restored, even if an outage should occur.

This last principle covers catastrophic events that involve physical damage to facilities potentially over a vast area. These events are often the result of very severe natural disasters or conditions with an extremely low probability of occurrence, such as major ice storms, major earthquakes, or extremely cold temperatures. Section VIII describes Hydro-Québec's work in this area in greater detail.

VI. HYDRO-QUÉBEC'S DEFENSE PLAN AGAINST EXTREME CONTINGENCIES

Because of its vast structure and the relatively small number of lines on its main transmission system (in comparison with the power carried), Hydro-Québec's system is vulnerable to incidents that could cause chain reactions and the loss of several transmission lines. In fact, Hydro-Québec experienced three major power outages in the 1980s caused by extreme contingencies [1]. The consequences of these system-wide power failures were deemed significant enough to justify the establishment of measures that would limit their impact. Hydro-Québec therefore decided to deploy a defense plan against extreme contingencies [2]. The defense plan consists of all the automatic measures required to preserve the stability of the system and maintain acceptable voltage levels after extreme contingencies. It is the ultimate protection against the total collapse of Hydro-Québec's system following such an event.

Since the actions required to preserve the system's integrity must often be both fast and massive, Hydro-Québec has defined a number of principles underlying the design of its defense plan. The most important design principles are as follows.

- The means used to counter extreme contingencies must never put system or equipment safety in jeopardy during a false trip or unintended operation.
- The SPS must first and foremost be simple, even at the risk of losing some selectivity. For this purpose, the various extreme contingencies possible in a substation must be grouped in a limited number of categories.
- The preference is for SPSs with local detection and action. Since there is a very large number of possible extreme contingencies, it is thus preferable to detect the consequences of a contingency on the power system rather than try to detect the actual contingency.
- The preferred means are those with the least impact on service continuity. It is, however, preferable to voluntarily eliminate a portion of the load than to lose all of it by allowing the system's behavior to deteriorate. The use of remote load shedding must be minimized and requires a high level of security.
- Substation protection against extreme contingencies must use an "umbrella" approach. For instance, if a given solution covers the loss of four substation lines, the loss of three lines must also be covered.

One of the main problems encountered in developing a defense plan against a set of extreme contingencies is to ensure the *coordination* of the various measures used. It is necessary for each measure to have a clearly defined task to perform, given the many situations and system behaviors that could occur. Thus, during complex extreme contingencies involving a number of automatic measures, no outside coordination must be required. Each system must be able to act as a function of its own contingencies, and the combination of actions should make it possible to preserve power system stability. Detailed studies on all aspects of power system stability and behavior have made it possible to determine that the measures adopted contain enough flexibility to meet this important constraint.

The analysis of multiple extreme contingencies in relation to the design principle led to the recommendation of the following SPS.

- An underfrequency load-shedding system installed in about 150 distribution substations which can access over 13 000 MW of load.
- Automatic shunt reactor systems (called MAIS [3]) installed in twenty-two 735-kV substations which control about 15 000 MVAR.
- An SPS involving generation rejection, load shedding and remote reactor tripping at 735 kV. Called RPTC [2], this SPS is designed to detect multiple line losses or series-compensated capacitor bank tripping in 15 strategic 735-kV substations;
- An undervoltage load-shedding system able to shed 1500 MW of load, mainly found in 735-kV substations in the Montréal area.

The defense plan against extreme contingencies uses three levels of increasing automatic intervention, to counteract extreme contingencies of increasing severity.

1) *The first level* is based on limited generation rejection combined with tripping 735-kV shunt reactors. Together, they make it possible to preserve the system's stability without affecting service continuity after the loss of two 735-kV parallel lines during peak periods. For the loss of two parallel lines involving voltage stability phenomena, undervoltage load shedding is also allowed.
2) *At the second level of intervention*, the effect of extreme contingencies is detected on the system. The automatic switching (closing or tripping, as appropriate) of 735-kV shunt reactors and undervoltage and underfrequency load shedding preserves the stability of the system for a very wide range of situations. These local means of detection and measures allow system integrity to be preserved for all extreme contingencies in at least half of the 735-kV substations. At this level of intervention, it is not always possible to avoid some load loss, but the loss is limited.
3) *Finally, on the last level*, direct detection of extreme contingencies is required. To ensure adequate efficiency, rapid and massive generation rejection and remote load shedding are required after event detection to counter transient and dynamics phenomena. The load loss will be large, but it is the only way to avoid a total power outage.

All generation rejection and load shedding actions are modulated in real time by the system control center to reduce the amount of actions at the right value while maintaining a safe level of operation.

Table 4 shows the possible operation of each measure for the various extreme contingencies as well as the role played by each of them.

Table 4
Possible Automatic Actions to Counter Extreme Contingencies

	EXTREME CONTINGENCIES	MAIS		UVLS	UFLS	RPTC		
		Closing	Tripping			Limited GR	GR and RLS	RTS
LEVEL 1 Limited action	Loss of two series or parallel 735-kV lines		*	*		*		*
	AC-DC event; loss of a bipolar line with loss of one 735-kV line		*	*		*		*
LEVEL 2 Use of curative type SPS	Loss of a generating station or generation unit at a station	*			*			
	Sudden loss of a major load centre	*						
	Unintended operation of an SPS	*			*			
LEVEL 3 Use of SPS with massive actions	Loss of lines and bypass of all series capacitors on the remaining lines in the same corridor		*	*	*		*	*
	Loss of all 735-kV lines in a corridor	*			*		*	
	Loss of all 735-kV lines originating from a substation	*			*		*	

MAIS: Automatic 735-kV Shunt Reactor Closing or Tripping, UFLS: Underfrequency Load Shedding, UVLS: Under-Voltage Load Shedding, RPTC: Generation Rejection (GR), Remote Load Shedding (RLS) and Remote Tripping of Shunt Reactor (RTS).

VII. HYDRO-QUÉBEC'S DEFENSE PLAN AGAINST SYSTEM SEPARATION

Hydro-Québec's 735-kV transmission system is made up of two 1000-km branches linking isolated generating centers to the north to the load center in the south. Unexpected events more severe than the extreme contingencies listed in Table 3 may create system instability, though this is highly unlikely given the measures in place. However, should this occur, the impact on the facilities could be disastrous if no additional precautions are planned. On such a system, a severe fault could result in an out-of-phase condition between remote generating facilities and, subsequently, the separation of the two major transmission branches caused by tripping of all the lines. Following a system separation, severe temporary overvoltage (TOV) due to the Ferranti effect appears on long unloaded lines which are still connected to generators. Strategic equipment must be protected against these excessive temporary overvoltages in order to ensure that system restoration will always be an option. All measures deployed to protect strategic equipment in relation to electrical constraints are combined under the name of "defense plan against system separation" (SPSR).

The SPSR system is divided in two parts: the first one was installed on the James Bay system, and the second was implemented on the Churchill Falls system.

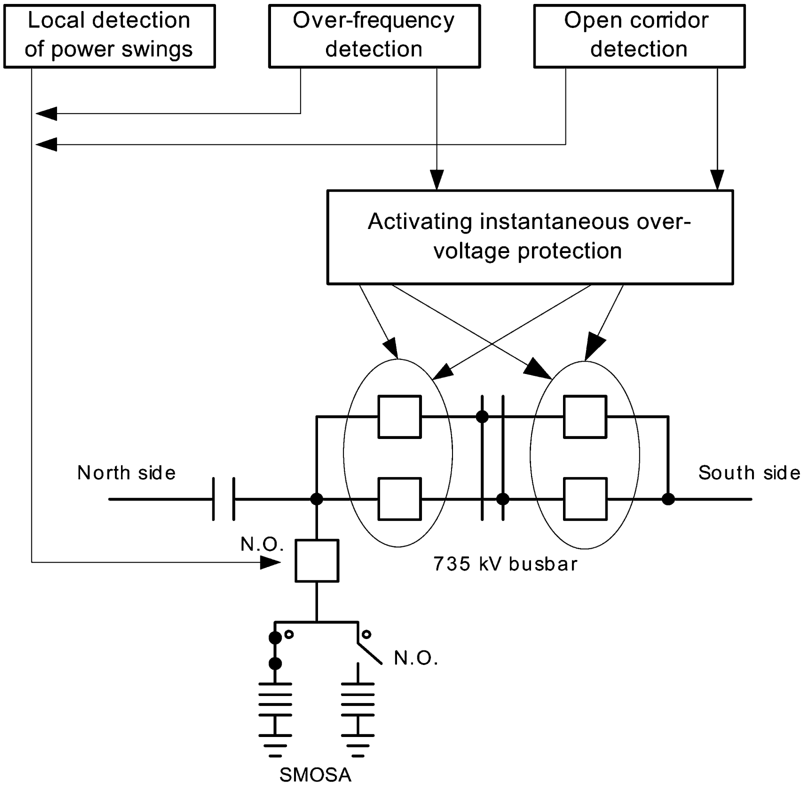

Fig. 4. SPRS system functional diagram.

A. James Bay SPSR

The James Bay SPSR system relies mainly on instantaneous 1.4 per unit (p.u.) overvoltage protections and on special switched metal–oxide surge arresters (SMOSAs). Together they ensure that, should a system separation occur, all unloaded lines will be removed rapidly by 1.4 p.u. overvoltage protections and TOV magnitude will be controlled to approximately 1.60 p.u by the presence of the surge arresters.

The instantaneous 1.4 p.u. overvoltage protections are installed on all line terminals in each substation of the James Bay system. To ensure safe operation, these overvoltage protections are not active under normal operating conditions. The metal–oxide surge arresters installed at the Abitibi, Chibougamau, La Vérendrye, Chamouchouane, and Saguenay substations have a rated voltage of 484 kV rms. Since their rated voltage is too low to allow them to be permanently connected to the system, they must be switched on only for a limited time during system disturbances.

The two corridors of the James Bay system are independently protected by an SPSR system. The western corridor is delimited by the LG-2, Radisson, Némiscau, Abitibi, La Vérendrye, Grand Brûlé, Chénier, and Duvernay substations. The eastern corridor includes the Lemoyne, Albanel, Chibougamau, Chamouchouane, Saguenay, and Jacques Cartier substations. Fig. 4 presents a flow diagram illustrating SPRS operation. As shown, the detection mechanism is composed of three main parts:

- local power swing detector to locally switched on SMOSA;
- overfrequency relays at the Radisson and LeMoyne substations;
- open-corridor conditions found on all James Bay substations and initiated by the loss of all 735-kV lines in the same corridor.

Overfrequency detection and detection of open-corridor conditions activate all instantaneous 1.4-p.u. overvoltage protections and switch on all SMOSAs in its corridor. Activation of 1.4-p.u. overvoltage protection will allow for structured and safe dismantlement of lines in the event of system separation.

B. Churchill Falls SPSR

The Churchill Falls SPSR system is similar to the one installed on the James Bay system, except that there is no SMOSA because of less severe temporary overvoltages. The Churchill Falls SPSR scheme is applied on the North Shore corridor and includes the Churchill Falls, Montagnais, Arnaud, Micoua and Manicouagan substations.

Operation of the Churchill Falls SPSR is fairly simple: following the detection of an overfrequency (at the Churchill or Montagnais substation) or the detection of the loss of a corridor (at the Montagnais or Arnaud substation), a signal is emitted to enable all instantaneous 1.2-p.u. overvoltage protections at the Montagnais and Arnaud substations. Overvoltage protection systems will quickly remove all unloaded lines in the corridor to reduce TOV duration. These overvoltage protection systems are not active under normal operating conditions to ensure safe operation.

VIII. HYDRO-QUÉBEC'S DEFENSE STRATEGY AGAINST CATASTROPHIC EVENTS

It is impossible to be totally immune from the major risks related to catastrophic events. However, the lessons learned from the 1998 ice storm led Hydro-Québec to develop a global and structured approach to determine how to deal with such contingencies or minimize their impacts.

The approach retained is based on an assessment of risks since it is not economically feasible to implement radical measures to efficiently counter all of these phenomena. The approach consists of:

- simulating the different possible damage scenarios;
- assessing the reaction of the various power system components;
- determining their impact in terms of service interruption;
- determining the best ways to counter them.

This method is thus based on two notions, i.e., determining the vulnerability of equipment toward a given event at a given probability and assessing the consequences of equipment failure on service continuity. The results of this assessment are then compared against socially acceptable risks. Note that in determining a solution, it is necessary to first define the population's catastrophe tolerance level. We know by experience that this tolerance level varies based on the probability of occurrence of the given events. For instance, the 1998 ice storm represented a loss of 10 million customer-days, which was considered too high a social cost. The tolerance level that is currently socially acceptable for catastrophic events ranges from 1.5 million to 3.0 million customer-days.

The following damage scenarios are currently being studied:

- ice storms;
- earthquakes;
- mechanical damage to strategic substations;
- extreme temperatures;
- massive loss of telecommunications networks and computer risks;
- high winds and flooding in the Montréal area.

We will briefly review the actions and measures taken by Hydro-Québec in the management of the risks related to ice storms, earthquakes, and extremely cold temperatures (these studies being the most developed to date).

A. Risk Management Regarding Ice Storms

Determining the level of exposure to freezing rain and ice is mainly based on collection of data by Hydro-Québec on the accumulation of ice at over 50 weather stations throughout the province that have been in operation for over 20 years.

To prevent an exceptional situation such as the one experienced during the 1998 ice storm from recurring, Hydro-Québec has drawn up a number of guidelines in relation to power system and facility design as well as measures to speed up the restoration of service [5]. These guidelines consist of the following.

- Develop a minimum backbone power system which can be counted on when having to face extreme climatic events. Fig. 5 illustrates the concept of 735-kV strategic lines which ensure a supply to cover at least 80% of needs following extreme climatic conditions. The 735-kV lines shown in bold on the figure will either be reinforced to withstand an ice storm with a recurrence rate of once every 50 years or deiced. The figure also shows the four projects currently being prioritized, i.e., adding a deicing system at the Lévis and Boucherville substations and reinforcing the strategic lines connected to the Manic and Duvernay substations;
- Implement measures to strengthen the regional networks so as to make the electrical supply 50% secure in four days and most of the load secure in 21 days. These measures may consist of mechanical reinforcement or deicing;
- Update the mechanical design criteria for new transmission lines so that they are capable of withstanding an icing load with a 50-year recurrence rate for regular lines and a 150-year recurrence for strategic lines.

Several projects resulted from the major guidelines mentioned previously, including the following.

1) Adding a new 735-kV line between the Des Cantons-Montérégie-Hertel substations. The line, which is 145 km long and was commissioned in December 2003, allows a 735-kV loop to be created in the southern part of Hydro-Québec's transmission system. The line will also provide the Montréal area (via the Hertel substation) and the Montérégie area (through the new 735-kV/120-kV Montérégie substation) with an additional source of supply originating from a corridor that is geographically separate from existing corridors.
2) Adding a 315-kV line between Aqueduc and Atwater substations in order to loop the downtown Montréal core.
3) Measures currently being planned for 2006 and 2008 include adding a deicing system at the 735-kV Lévis substation in the Québec City area and at the Boucherville substation in the Montréal area. These deicing systems, which use a Statcom/dc source, will be connected alternately on strategic lines linked to the above substations when required. The operating principle consists of injecting a 7200-A direct current into two phases of the same line that were previously short-circuited. Under normal operating conditions, the deicing system will be connected to the power system and act as a static compensator.
4) Mechanically reinforcing target lines at the Duvernay and Manicouagan substations for 2008 and 2009, respectively.
5) Initiating several projects on regional networks by 2010 to deice the lines using simpler technologies: reduced-voltage short-circuit or increasing the current using a phase-shifting transformer.

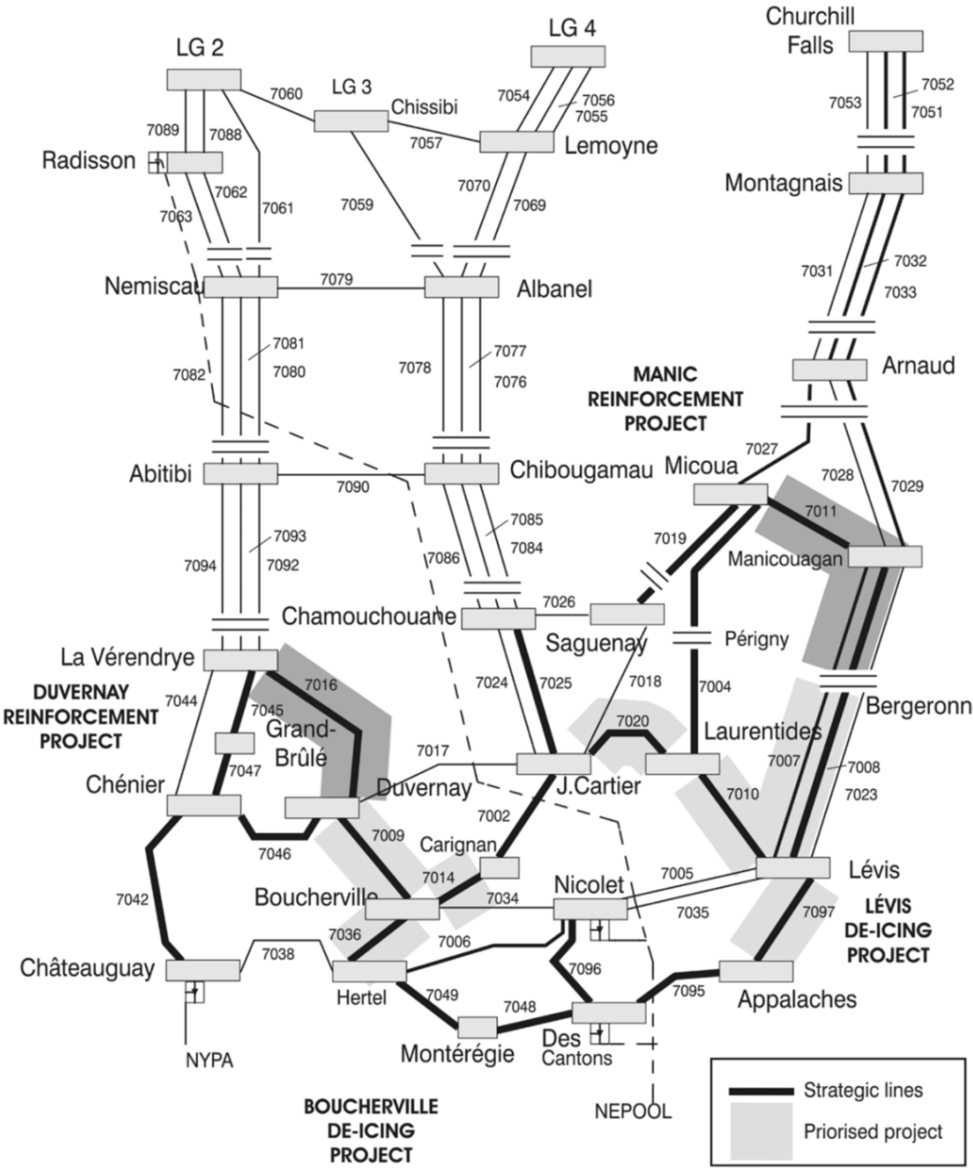

Fig. 5. Hydro-Québec's 735-kV strategic lines.

6) Mechanically reinforcing certain regional lines by 2010.

Once implemented, these measures will have resulted in expenditures of over $1 billion.

B. Risk Management Regarding Earthquakes

The earthquake impact study aims at assessing the risk incurred by Hydro-Québec's facilities and defining measures whereby they are able to withstand potential earthquakes with an acceptable level of risk.

The area occupied by Hydro-Québec's facilities has been divided into six seismic activity zones with, as base of reference, a probability of exceedence of 10% every 50 years. The facilities in the zones with the highest rate of seismic activity were all subjected to an in-depth risk assessment. These facilities are mainly located south of Québec city and in Gaspésie peninsula. The components reviewed in each of the 62 facilities included all electrical equipment mounted on a pad (e.g., current transformer) or concrete base (e.g., voltage transformer), control buildings, and control and protection equipment.

Table 5
Risk Assessment for the 62 Most Vulnerable Facilities

Risk level (out of a scale of 100)	**Number of facilities affected**
High (40 to 100)	7
Moderate (21 to 39)	31
Low (11 to 20)	10
Negligible (1 to 10)	14

Each facility was given a risk rating (out of a scale of 1–100) determined based on the vulnerability of its components and the potential impact of a failure. Table 5 summarizes the results of the evaluation for the 62 substations reviewed.

In all the facilities where the risk level is considered to be high, mitigation measures were studied in depth. The diverse group of measures includes anchoring equipment to the ground, strengthening and bracing buildings, and using dampers or guy wires on equipment. Note that a series of field tests was used to define the fragility of equipment as well as the best intervention measures and that a probability of exceedence of 2% every 50 years instead of 10% was used. The total cost of the work required for the substations considered to be at high risk is about $18 million. Studies for substations with a lower risk level are under way and corrective measures are in the process of being drawn up.

C. Risk Management Related to Extreme Temperatures

The impact study related to extreme temperatures aims at determining the impact of this phenomenon on equipment and on the transmission system. Extreme cold is of specific concern mainly because the apparatus is generally better protected against overheating than against cold and demand is very high during cold weather. As a result, the power system will not benefit from a very large operating margin, which will exacerbate the potential impacts from equipment breakdown or failure. Furthermore, more and more in-service equipment uses gas mixtures such as SF_6-N_2. These mixtures change properties at very low temperatures and lose their electrical characteristic, thus putting the power system at greater risk.

The analysis of climatological data reveals that it is quite possible that, over long periods of recurrence, some parts of the power system are subjected to temperatures as low as -55 °C. Note that there are currently two ambient temperature ranges for the design of electrical apparatus installed on Hydro-Québec's 735-kV transmission system: -40 °C to $+40$ °C and -50 °C to $+40$ °C, depending on the geographic location of the equipment on the power system. Equipment inside buildings or heated cabinets is specified for an ambient temperature of -5 °C to $+40$ °C.

Current studies aim at reviewing the behavior of in-service equipment with the assumption that temperatures fall as low as -55 °C and -60 °C. The equipment reviewed consists of circuit breakers, power transformers, shunt reactors, voltage and current transformers, and disconnectors. Scenarios will then be drawn up to identify the risks related to such extremely low temperatures.

IX. CONCLUSION

Several R&D projects are under way to ensure that Hydro-Québec continues to fulfill its basic mission, namely, that of supplying electricity to Québecers in a reliable manner and at the least possible cost. These projects, carried out in close cooperation with major electrical equipment manufacturers, aim to increase the capacity, flexibility and security of Hydro-Québec's transmission system. Some of the projects include the following.

- The design of a new multiband power system stabilizer capable of simultaneously and efficiently dampening all electromechanical oscillation modes that can occur under different power system configurations.
- The design of a new open-line detector (DLO). Fully digital and based only on electrical variables, the DLO is capable of *locally* detecting when a line is open, whether at one end of the line or the other, and without the use of telecommunications.
- The design of a new control system capable of detecting the imminent instability of a generating station using only local electrical variables.
- The design of a detector capable of remotely sensing voltage instability.
- The commissioning in 2004 of a new type of interconnection developed by a manufacturer, the variable frequency transformer (VFT), designed to isolate power systems.

These projects are all part of a new generation of measures that will help Hydro-Québec deal with the challenge of an expanding power system and the resulting constraints.

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