CANADIAN ELECTRICAL ASSOCIATION

Power Resource Planning and Operation Subsection

Power System Planning and Operation Section

Engineering and Operating Division

March 1995
Vancouver

MARGINS FOR UNCERTAINTIES IN HYDRO-QUEBEC'S SHORT-TERM OPERATIONS PLANNING

M. BEAUMONT M.P. RAYMOND
HYDRO-QUEBEC
C.P. 10000
MONTREAL, QUEBEC
H5B 1H7

SUMMARY

Hydro-Quebec's hydraulic and nuclear resources are generally sufficient to meet load except during winter peak periods when other resources are needed (e.g. thermal generation, purchases, interruption of external and internal loads, etc.). These resources are costly and in most cases have operating constraints such as minimum and maximum number of hours daily and annually, in addition to having time delays. Such delays may vary from a few hours (external contracts, purchases) to up to 18-24 hours (internal interruptible loads, thermal plant). Decisions regarding the use of such resources must therefore be taken in advance and must take into account the uncertainties on load forecast and on the availability of hydraulic units. The amount of short-term margins chosen within this decision-making process will have an impact on operation costs and risks of deficiency. It will also have an impact on the value of resources from a planning perspective. A method has been developed at Hydro-Quebec for establishing the short-term capacity margin requirements to deal with uncertainties from 1 to 24 hours in advance.

Keywords: reserve margins, reliability, load forecast errors, unit forced outages, short term operations planning.

1. INTRODUCTION

Hydro-Quebec's hydraulic and nuclear resources account for 95% of the utility's generating capacity and are generally sufficient to meet load except during winter peak periods where non-hydraulic resources are needed (e.g. thermal generation, purchases, interruption of external and internal loads).

Such resources are usually more costly than hydraulic and nuclear generation and therefore must be managed in an optimal way. The difficulty in managing these resources resides in the fact that there are operational constraints such as minimum and maximum number of hours per use, minimum number of hours between two consecutive uses, and maximum number of hours per year. Most importantly, these resources cannot be started up instantaneously but require time delays that vary from less than one hour to up to 24 hours.

Time delays require operators and short-term planners to make decisions in advance based on forecasts that sometimes carry significant variances caused by uncertainties on load and capacity. Decisions must therefore be taken with capacity margins that must take the uncertainties into account. An overly small margin will increase the risk of not meeting firm load or real-time reserve requirements while a margin that is too high will result in unnecessary costs or improper utilization of annually limited resources that may lead to reliability problems for the remainder of the winter period.

The objective of this paper is to present Hydro-Quebec's approach in determining an optimal margin policy to be used by operators and short-term planners in managing non-hydraulic resources while reducing the overall cost and maintaining proper reliability standards.

2. HYDRO-QUEBEC'S GENERATING SYSTEM

Hydro-Quebec operates a power system for the generation, transmission and distribution of electricity. Its power system is characterized by a large proportion of hydroelectric generation. According to 1994 figures, 95% of the utility's installed capacity of roughly 30,500 MW is hydroelectric. During 1994, 96% of the 140 TWh of energy generated came from the utility's 54 hydroelectric plants, while the remaining 4% was supplied by the Gentilly 2 nuclear plant. Less than 1% was generated from other thermal plants to meet peak demand and to supply remote areas.

The system is interconnected to neighboring systems in Canada and the U.S. Import and export transactions with neighboring systems involve firm and interruptible capacity and energy.

3. DESCRIPTION OF THE PROBLEM

In order to meet its load requirements during the winter period, Hydro-Quebec may occasionally have to resort to resources that are more costly than the base load generation of hydraulic and nuclear plants.

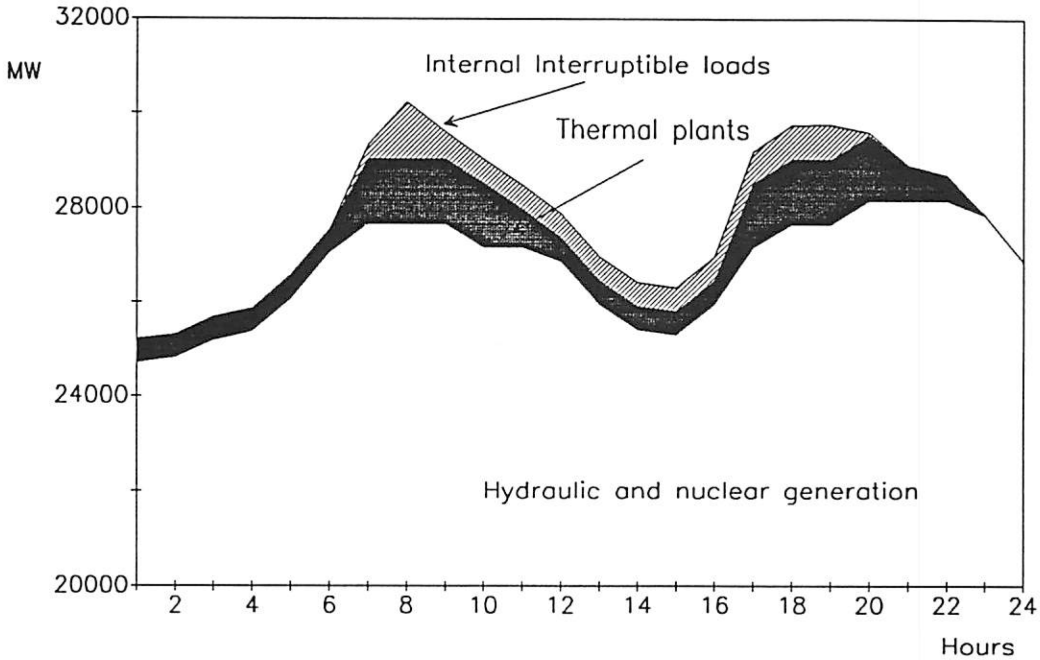

Figure 1. Generation for a typical winter peak day

Figure 1 shows the generation mix needed on a typical winter peak day. Most of the load requirements are met through hydroelectric and nuclear generation (where maintenance is kept at a minimum during winter). The peaks must be managed by non-hydraulic resources that have specific constraints as outlined in Table 1.

TABLE 1

Main characteristics of non-hydraulic resources

Resource	Time delay (hours)	Minimum hours per use	Maximum hours per day	Annual maximum usage
Interruptible exports	1-4			In some cases
Capacity imports	1-4			
Thermal plant	12	48		
Internal	18 *		2 x 5	yes
interruptible loads	18 *		1 x 16	yes

* May be cancelled 3 hours in advance.

In the case of internal interruptible loads totalling about 2000 MW on Hydro-Quebec's system [1], they are limited both daily and annually and their use must be carefully planned so that they remain available throughout the winter period. A Monte Carlo chronological simulation model [2] that takes into account the uncertainties on load and capacity is used for the annual planning of the non-hydraulic resources.

The most important constraint here is the time delay needed to start up the non-hydraulic resources. This time delay may vary from less than one hour to up to nearly 24 hours depending on the resource. Time delays require that operators and short-term planners make decisions based on forecasts that carry significant variances. One cannot neglect the uncertain nature of the main parameters when making decisions on the use of non-hydraulic resources a certain number of hours in advance.

The purpose of this paper is to describe how Hydro-Quebec has designed a short-term margin policy to be used by operators and short-term planners that will reduce costs while maintaining reliability standards.

Other utilities have addressed this problem in different ways. Ontario Hydro [3] uses a deterministic margin based on contingencies and load forecast uncertainties (LFU) with no assessment of the cost of such strategies versus the risk of not meeting real-time reserve requirements. Electricité de France [4] uses a margin based on a stochastic approach that takes into account uncertainties on internal load forecast and on unit forced outages. The margin is chosen by determining an accepted risk of having to use exceptional measures such as emergency purchases or curtailment of loads.

The approach chosen by Hydro-Quebec is similar to the one used by EDF and takes the following into account:

- uncertainties on internal load forecast;
- uncertainties on unit forced outages;
- accepted risks of not meeting firm load;
- accepted risks of not meeting real-time reserve requirements (e.g. 10- and 30-minute reserves);
- costs of non-hydraulic resources;
- time delays for non-hydraulic resources;
- operating constraints of non-hydraulic resources.

4. UNCERTAINTIES ON INTERNAL LOAD FORECAST

The most important uncertainty that operators and short-term planners have to consider is related to the forecasting of climatic conditions. For example, 1°C of difference in air temperature amounts to a difference in load of roughly 350 MW in winter. Although the short-term load forecasting model is efficient, errors in climatic forecasting one day in advance may sometimes lead to errors of more than 1500 MW on cold winter days when non-hydraulic resources are most likely to be called upon. Underestimating load may result in reliability requirements not being met, while overestimating load may lead to unnecessary costs.

Figure 2 depicts the standard deviation of the forecast error, based on historical data, for forecasts made 1 to 24 hours in advance. Three curves are needed to illustrate differences between three different periods of the year; however, only the winter curve is relevant to this study.

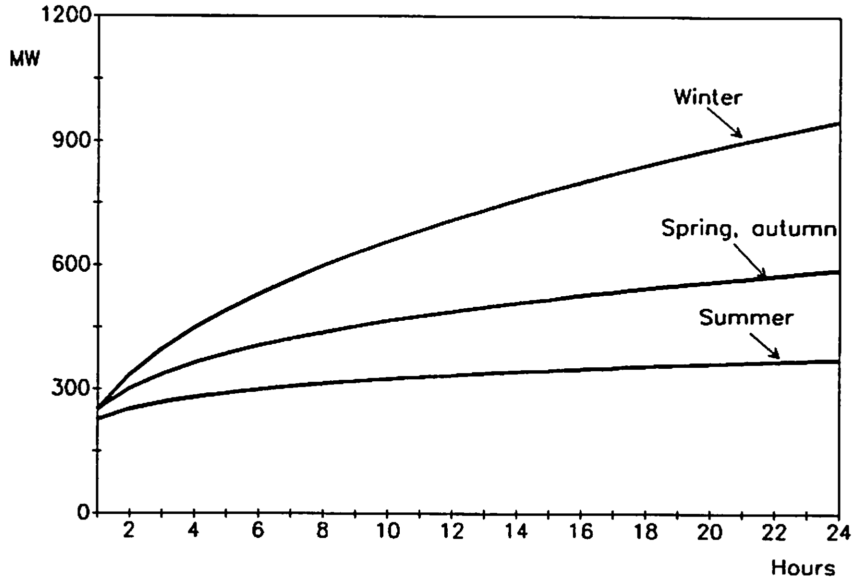

Figure 2. Standard deviation on internal load forecast

We can assume that forecast errors follow a normal distribution with mean zero and standard deviation shown in Figure 2.

5. UNCERTAINTIES ON UNIT FORCED OUTAGES

The second source of error in short-term planning comes from unexpected unit outages. Unlike load forecast errors, unit outages are never favorable.

The distributions of total unit forced outages (in MW) for the next 1 to 24 hours were obtained through the following steps:

(i) Using Monte Carlo simulation, a large number of 24-hour patterns for each unit in the system is generated. A pattern consists of a succession of states where the unit is in service followed by states where the unit is out of service, with each state lasting a certain number of hours. Most of the patterns will have a single state of 24 hours in service. Few patterns will have hours where the unit is out of service and these will contribute to building the distributions of total unit forced outages of the system.

The in service state is determined by an exponential distribution with mean h_1 hours, while the out of service state is determined by an exponential distribution with mean h_2 hours, where

$$\frac{h_2}{h_1 + h_2} = \text{F.O.R.} \qquad (1)$$

F.O.R. being the Forced Outage Rate. See [5] for more details. In Hydro-Quebec's power system, h_1 and h_2 are based on historical data. The present F.O.R. used in studies is 2% for hydraulic units during the winter period. In recent winters, Hydro-Quebec has been able to achieve even lower rates.

(ii) Each of the large number of simulations obtained in (i) above has produced a vector containing the total capacity (in MW) out of service for the whole system for the next 24 hours. For each hour, the mean and standard deviation of total forced outages (in MW) is computed. The lower curve in Figure 3 shows the resulting standard deviation of unit forced outages.

6. COMBINING UNCERTAINTIES

In order to easily combine the uncertainties on internal load forecast with the uncertainties on unit forced outages so that overall uncertainty may be obtained, major assumptions must be made.

- the unit forced outages for hours i = 1, ..., 24 are normally distributed with non zero mean (N $(\mu_{1,i}, \sigma_{1,i})$);
- the internal load forecast errors for hours i = 1, ..., 24 are normally distributed with zero mean (N $(0, \sigma_{2,i})$);
- the two distributions are independant.

With these assumptions, we are able to define a global distribution of uncertainties for each hour i = 1, ..., 24 with mean $\mu = \mu_{1,i}$ and standard deviation

$$\sigma_i = \sqrt{\sigma_{1,i}^2 + \sigma_{2,i}^2} \qquad (2)$$

Figure 3 shows the standard deviations $\sigma_{1,i}$, $\sigma_{2,i}$, and σ_i for hours i = 1, ..., 24.

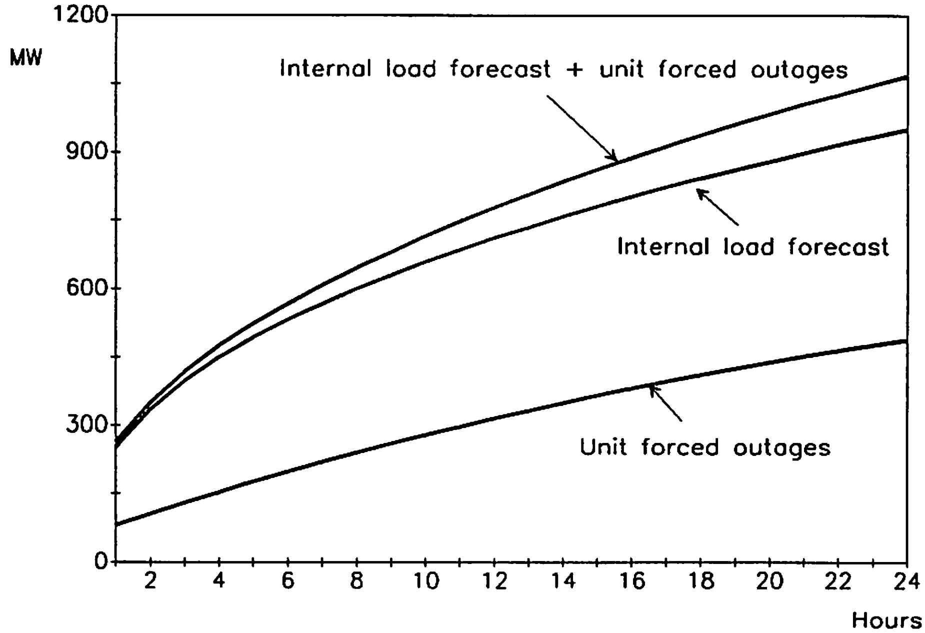

Figure 3. Standard deviation for combined uncertainties

Once the combined distributions are known, it is possible to obtain the uncertainties in MW for any risk of exceedence for 1 to 24 hours. Figure 4 shows such uncertainties for risks ranging from 1% to 30%. According to the figure, there is a 1% probability that the uncertainty exceeds 600 MW one hour in advance or that the uncertainty exceeds 2,500 MW 24 hours in advance.

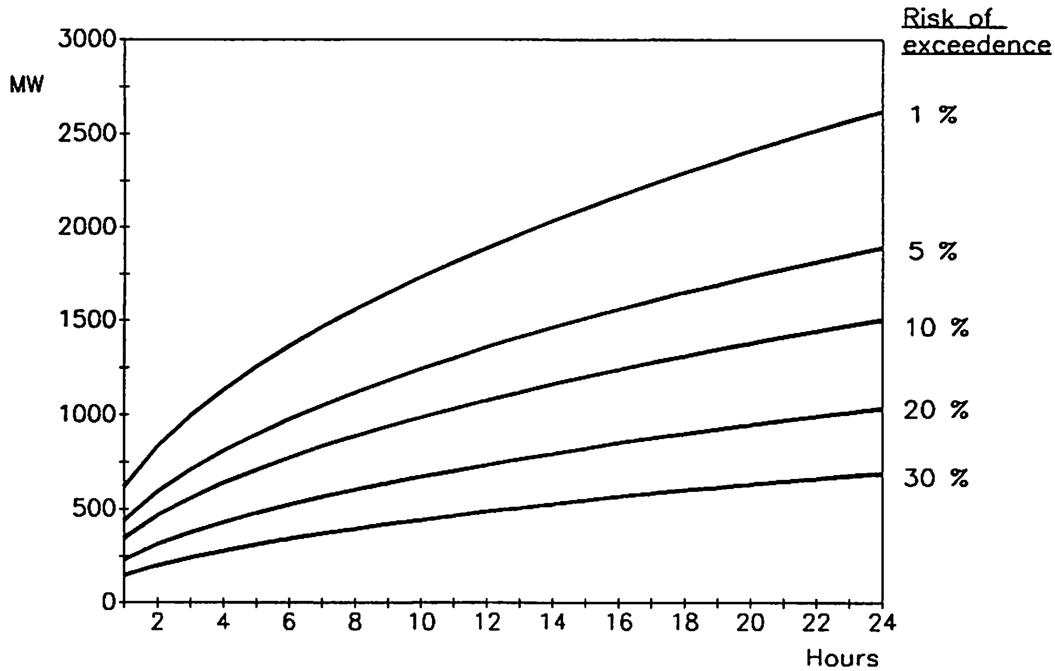

Figure 4. Combined uncertainties for load forecast and unit forced outages

7. SELECTING A RISK LEVEL

Once the distribution of combined uncertainties is determined, power system managers must select an acceptable risk level, while keeping in mind that a lower risk leads to higher costs in non-hydraulic resources.

One possibility involves a risk level that is equivalent to the reliability criterion used in long-term and mid-term planning which consists of 2.4 hours of not meeting firm load in each year. With respect to Hydro-Quebec's system, we evaluate that such a criterion would correspond to a risk of about 1% for those hours of the winter where non-hydraulic resources are likely to be needed.

Another way of choosing a risk level is by economic analysis. By varying the risk (and the margin in MW to be used in decision-making), we were able to evaluate the cost by using an hourly chronological Monte Carlo simulation model [1] for a given winter period that simulates the use of non-hydraulic resources. A plot of cost versus risk is then available for managers to select an acceptable risk level.

8. BUILDING A MARGIN POLICY

After selecting an acceptable risk level, the evaluation of the margin is done for different time delays.

Suppose we want to cover the risk of not meeting firm load. If we choose a 1% risk, the required margin would be the one represented by the broken curve in Figure 5.

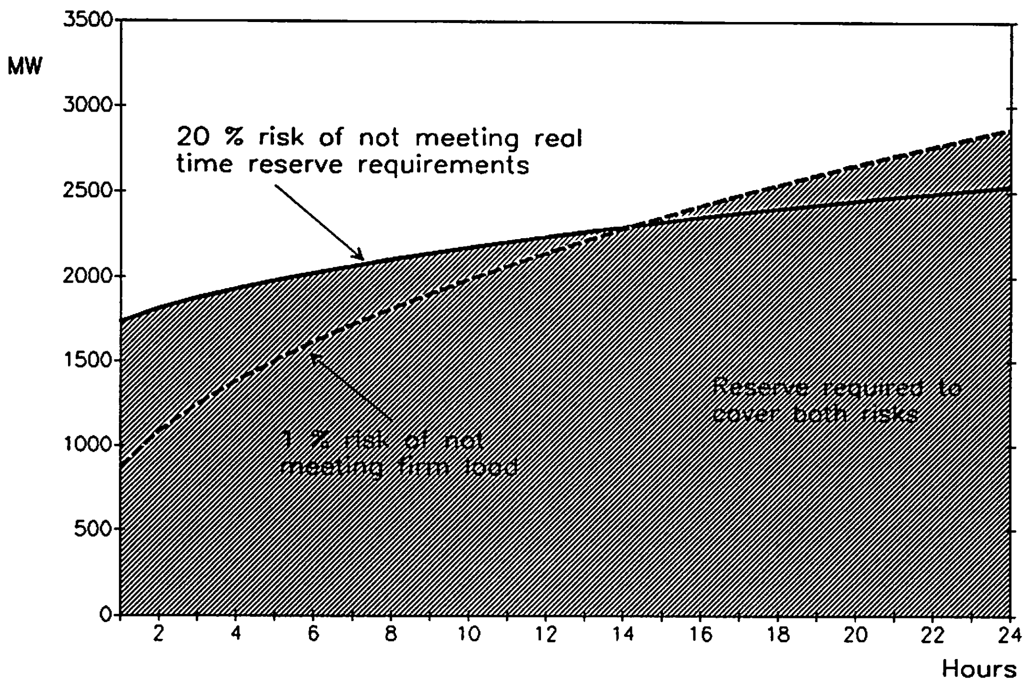

Figure 5. Reserve requirements for short term planning

This broken curve shows the MW reserve necessary 1 to 24 hours in advance. It includes the real-time reserve at which firm load is curtailed (in this case, 250 MW) and the uncertainties for a 1% level (that varies for each hour of delay) as taken from Figure 4. For example, decisions taken 24 hours in advance must be based on a forecast reserve of nearly 3,000 MW in order to have less than 1% probability of not meeting firm load.

For decisions made less than 14 hours in advance, meeting the above criterion requires less than the 30-minute reserve requirement in Hydro-Quebec's power system (1,500 MW in this example). In these cases, we must therefore focus on not violating the reserve requirements. If we choose a 20% risk, we obtain the continuous curve in Figure 5. If both risks are to be covered, then we must use the upper area of the two curves in Figure 5 (the shaded area) as our policy.

Table 2 presents a simple policy that could be given to power system operators.

TABLE 2

Sample margin policy

Time delay (hours)	Resource	Margin required above real-time reserve requirements (MW)
1	Interruptible exports A Capacity imports A	200
2	Interruptible exports B	300
3	Cancellation of internal interruptible loads	300
4	Interruptible exports C Capacity imports B	400
12	Thermal plant	700
18	Internal interruptible loads	1000

For each time delay where resource-planning is required, the table gives the margin (in MW) that must be guaranteed in addition to the real-time reserve requirements (1500 MW in this example). In other words, if the operator forecasts a reserve of less than 2200 MW for the 12th hour from now, he must order the start-up of the necessary number of units from the thermal plant. It is important to note at this point that when the operator assesses such a 12-hour reserve, he must include all the resources that could potentially be called upon in less than 12 hours.

9. POSSIBLE IMPROVEMENTS

Only two uncertainties are currently being modelled: internal load forecast and unit forced outages. Other minor uncertainties such as hydraulic constraints (from daily regulated reservoirs) and transmission forced outages could be explicitely modelled or a provision could be made when choosing the acceptable risk level.

A noteworthy improvement would be possible if daily load forecasts were accompanied by a standard deviation varying from day to day depending on the confidence level of the meteorological parameters. Instead of being supplied with a simple policy such as in Table 2, the operators would use a simple computer program that allows them to calculate the required margin of each hour as a function of the forecasted standard deviation.

10. CONCLUSION

The purpose of setting a margin policy is to supply the operators of the system with a simple set of rules to be used when decisions have to be taken on activating or not non-hydraulic resources.

These rules are given for different time delays and imply a risk level that has been chosen while taking into account the overall cost of the non-hydraulic resources needed.

Although the margin policy is used in short-term operations planning, it will also have an impact on long-term generation planning. For example, long-term generation planning has to assess the relative value of programs such as the internal interruptible loads as compared to a 100% efficient resource. Evaluation is done by simulating the use of these interruptible loads while taking into account the operational constraints, one of which being the MW margin used by operators in deciding to call upon this resource.

The development of a margin policy to take into account short-term uncertainties is beneficial to Hydro-Quebec to optimize the use of its non-hydraulic resources for peaking purposes.

REFERENCES

1. M. P. Raymond, "Planning and Operating Experience with Curtailable Loads," Panel Discussion, Canadian Electrical Association, 1994 Meeting, Toronto, March 20-24, 1994.

2. M.P. Raymond and T. Falcon, "Operations Planning of Hydro-Quebec Generation System Using Chronological Simulation," CIGRÉ Meeting of Study Committee SC-39, Montréal, September 10-14, 1991.

3. P. Nitu, "Survey of North America Utilities Operations Planning Criteria," Canadian Electrical Association, 1994 Meeting, Toronto, March 20-24, 1994.

4. G. Collognat, "Introduction à la gestion prévisionnelle de la production", EDF Internal Document, June 1994.

5. R. Billinton and R. N. Allan, *"Reliability Evaluation of Power Systems,"* Plenum Press, New York, 1984.